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 #17-4
October 11, 2017 10:00 a.m. – 5:00 p.m. EST
October 12, 2017 8:00 a.m. – 12:00 p.m. EST
Sir Adam Beck Generating Station
14000 Niagara Parkway, Niagara-on-the-Lake
Ontario, Canada
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 1, 2017
NPCC Glossary of Terms, dated January 14, 2014

Introductions and Chair's Remarks

NPCC Antitrust Compliance Guidelines

Agenda Items:

1.0 Review of Agenda

2.0 RSC Meeting Minutes

3.0 Drafting Team Members and Executive Tracking Summary

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

4.0 Open Action Items

4.1 Open Action Items List

5.0 Items Requiring RSC Discussion

5.1 NERC Weekly Standards Bulletin
5.2 NPCC 2017 Fall Compliance and Standard Workshop Topics
5.3 Compliance Guidance Presentation
5.4 FERC Rulings on RAS
5.5 RSC Scope of Work and Workplan
5.6 Reliability Issues Steering Committee (RISC)
5.7 DOE OE-417
5.8 Staff Report to the Secretary on Electricity Markets and Reliability and DOE Proposed NOPR

5.9 Project 2016-02 CIP-012-1 Presentation

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	10/11/17 Call-In
Project 2013-03 Geomagnetic Disturbance Mitigation TPL-007-2	8/11/17 (F)	8/11/17 (I)	Scott Barfield-McGinnis	1:00PM
Project 2016-04 Modifications to PRC-025-1	9/7/17 (F)	9/8/17 (I)	Scott Barfield-McGinnis	1:15PM
Project 2015-10 Single Points of Failure TPL-001	10/23/17 (F)	10/23/17 (I)	Latrice Harkness	1:30PM
Revisions to the NERC Standard Processes Manual	5/3/17 (F)	5/3/17 (I)	Chris Larson	1:45PM
Project 2017-01 Modifications to BAL-003-1.1	8/9/17 (F)		Darrel Richardson	2:00PM
Project 2017-02 Modifications to Personnel Performance, Training, and Qualifications Standards	7/24/17 (I)		Darrel Richardson	2:15PM
Project 2017-06 Modifications to BAL-002-2	8/9/17 (I)		Darrel Richardson	2:30PM
Project 2015-09 Establish and Communicate System Operating Limits	11/13/17 (F)	11/13/17 (I)	Darrel Richardson	2:45PM
Project 2017-05 NUC-001-3 Periodic Review			Mat Bunch	3:00PM
Project 2016-02 Modifications to CIP Standards CIP-002-6	10/30/17 (F)	10/3017 (I)	Katherine Street Mat Bunch	3:15PM
2018-2020 Reliability Standards Development Plan	7/25/17 (F)		Soo Jin Kim	3:30PM
Project 2017-03 FAC-008-3 Periodic Review			Al McMeekin	3:45PM
2017 Periodic Review Standing Review Team - Standards Grading	8/2/17 (I)		Laura Anderson	4:00PM
Project 2017-04 Periodic Review of Interchange Scheduling and Coordination Standards			Laura Anderson	4:15PM
Project 2017-07 Standards Alignment with Registration	8/30/17 (F)		Laura Anderson	4:30PM
Comments: (I) – Informal; (F) – Formal; (N) – Nomination Period **Ballots:** (I) – Initial; (A) – Additional; (F) – Final				

6.2 Ballot History (Since last RSC Meeting)

6.3 Comment Form History (Since last RSC Meeting)

7.0 NERC Drafting Team Nominations

7.1 Currently Posted Drafting Team Vacancies

7.1.1 None at this time

7.2 Closed Drafting Team Nominations (Since last RSC Meeting)

7.2.1 None at this time

7.3 Solicitation for Informal Development Teams

7.3.1 None at this time

8.0 NPCC Regional Reliability Standards

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

8.1 Current Activities:

8.1.1 PRC-006-NPCC-2 Automatic Underfrequency Load Shedding status update

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

9.0 NPCC Non-Standards

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

9.1 Directories:

9.1.1 Directory#8 *System Restoration*.

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

RAS Implementation/Transition

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

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

9.1.5 Directory#4 System Protection Criteria – (status of Eversource Clarification Request)

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 18th - Call	March 15th - Meeting	April 19th - Call
June 14th - Meeting	July 19th - Call	September 7th Meeting
October 18th - Call	December 6th - Meeting	

SC 2018 Schedule:

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

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

January 4th - Call	February 21st - Call	March 14th – Meeting
March 29th – Call	May 22nd - Call	June 13th – Meeting
June 28th – Call	August 18th – Call	September 6th – Meeting
September 28th – Call	November 14th – Call	December 5th - Meeting

SCPS 2018 Schedule:

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

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

January 26th - Call	March 15th - Meeting	April 27th - Call
June 14th - Meeting	July 27th - Call	September 7th Meeting
October 12th - Call	December 6th - Meeting	

PMOS 2018 Schedule:

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

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

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

February 8-9 - Meeting	May 10-11 - Meeting	August 9-10 - Meeting
November 7-8 - Meeting		

BOT 2018 Schedule:

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

12.6 Reliability Issues Steering Committee (RISC)
http://www.nerc.com/comm/RISC/Related%20Files%20DL/ERO_Reliability_Risk_Priorities_RISC_Reccommendations_Board_Approved_Nov_2016.pdf

13.0 NERC Items of Interest (Since last RSC Meeting)

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

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

13.2 Alerts

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

There has been one new NERC Alerts released since the last RSC meeting.

13.3 Final NERC 2018 Business Plan and Budget

14.0 Other Items of Interest

14.1 NPCC Compliance Committee (CC) Schedule

January 18th – Call	February 15th – Call	March 14-15th Meeting
April 12th – Call	May 23-25th Workshop	June 13-14th Meeting
July 12th – Call	August 16th – Call	September 19-20th Meeting
October 18th – Call	November 7-9th Workshop	December 7th Meeting

14.2 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

NPCC Board of Directors Meeting (BOD) 2018

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

14.3 NPCC Business Plan and Budget 2018

15.0 Future RSC Meetings and Conference Calls

15.1 RSC 2017 Meeting Dates

March 8th-9th, FRCC, Tampa FL
June 7th-8th, Saratoga NY
August 23rd-24th, Toronto
October 11th-12th, Niagara is on the lake, Ontario Canada
December 7th, Boston MA

15.2 RSC 2017 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 20	February 3	February 17
March 24	April 7	April 21
May 5	May 19	June 16
June 30	July 14	July 28
August 11	September 8	September 22
September 29	October 27	November 10
November 24	December 22	

15.3 Tentative RSC 2018 Meeting Dates

February/March, NextEra/Dominion, Juno Beach/Innsbrook
June, Saratoga NY
August, Toronto
October, Lewiston NY
December, Toronto ON

Respectfully Submitted,

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

Northeast Power Coordinating Council, Inc. (NPCC)

Antitrust Compliance Guidelines

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

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

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

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

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

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

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

NPCC REGIONAL STANDARDS COMMITTEE

AGENDA FOR MEETING #17-3
August 23, 2017 10:00 a.m. – 5:00 p.m. EST
August 24, 2017 8:00 a.m. – 12:00 p.m. EST
Hydro One North Tower
483 Bay Street
Toronto, Canada
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 July 14, 2017
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	2nd Day Via Phone
3.	Ruida Shu	Northeast Power Coordinating Council		1 & 2	
4.	Kal Ayoub	FERC	Guest	1	
5.	Mike Jones	National Grid	3	1 & 2	Via Phone
6.	Quintin Lee	Eversource Energy	1	1 & 2	
7	Herb Schrayshuen	Power Advisors, LLC - Proxy for NextEra Energy, LLC	4	1 & 2	
8.	Joel Charlebois	AESI, Inc.	Guest	1 & 2	
9.	Ron Falsetti	AESI, Inc.	Guest	1 & 2	
10.	Dan Grinkevich	Consolidated Edison Co. of New York, Inc.	1, 3, 4 & 5	1 & 2	
11.	David Kwan	Ontario Power Generation, Inc.	4	1 & 2	Via Phone
12.	Constantin Chitescu	Ontario Power Generation, Inc.	Guest	1	Via Phone
13.	Chantael Mazza	Hydro-Québec TransÉnergie	2	1 & 2	
14.	Laura Mcleod	New Brunswick Power Corporation	1	1 & 2	

15.	Payam Farahbakhsh	Hydro One Networks	1	1 & 2	
16.	Ben Wu	Orange & Rockland Utilities, Inc.	3	1 & 2	
17.	Salvatore Spagnolo	NYPA	4	1	Via Phone
18.	Brian Robinson	Utility Services, Inc.	5	1 & 2	
19.	Sean Bodkin	Dominion Resources Services	4	1 & 2	Via Phone
20.	Helen Lainis	IESO	2	1 & 2	
21.	Michele Tondalo	The United Illuminating Company	1	1 & 2	Via Phone
22.	Robert Blohm	Independent	Guest	2	
23.	David Kiguel	Independent	Guest	1 & 2	
24.	Kathleen Goodman	ISO-NE	2	1 & 2	Via Phone
25.	Josh Eason	ISO-NE	2	1 & 2	Via Phone
26.	Scott Barfield-McGinnis	NERC	Guest	1	Via Phone
27.	Chris Larson	NERC	Guest	1	Via Phone
28.	Darrel Richardson	NERC	Guest	1	Via Phone
29.	Mat Bunch	NERC	Guest	1	Via Phone
30.	Katherine Street	NERC	Guest	1	Via Phone
31.	Sean Cavote	NERC	Guest	1	Via Phone
32.	Laura Anderson	NERC	Guest	1	Via Phone

Introductions and Chair's Remarks

Payam Farahbakhsh welcomed everyone to Hydro One and provided a brief safety session for the facility.

NPCC Antitrust Compliance Guidelines

The NPCC Antitrust Compliance Guidelines were read by Ruida Shu.

Agenda Items:

1.0 <u>Review of Agenda</u>

Guy Zito added agenda item 5.5 Standards Grading and 5.6 GMD presentation.

2.0 RSC Meeting Minutes

Approval of Minutes—no additional revisions were made to the draft RSC meeting minutes of 6-7-17.

Herb Schrayshuen made a motion for approval.

Daniel Grinkevich seconded the motion.

The meeting minutes were approved as read.

3.0 Drafting Team Members and Executive Tracking Summary

3.1 NPCC Members on NERC Drafting Teams

The RSC members reviewed the roster and agreed to remove the second tab which recorded a history of executive tracking summary.

3.2 Executive Tracking Summary

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

3.3 NERC Project Tracking Spreadsheet

The RSC members reviewed the Project Tracking Spreadsheet as a group.
Kal Ayoub indicated that FERC has a full quorum now and he expect items will be moving forward in the near future.

4.0 Open Action Items

4.1 Open Action Items List

The RSC members reviewed the Open Action Items.

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 CC Implementation Guidance Process

Guy Zito provided background on the process.

The NPCC Compliance Committee Process for submitting Implementation Guidance to NERC is posted on the NPCC website.

Implementation Guidance does not equal to Compliance Guidance.

This topic belongs to Compliance Manager group to make any decisions, the process needs more updates and clarity.

Brian Robinson is planning to submit Implementation Guidance for PRC-005 to NPCC. ~~has been instructed by the RSC to draft an Implementation Guidance to submit~~.

5.3 Standards Oversight and Technology Committee – Standards Efficiency Review

Guy Zito provided a brief overview on the Standards Oversight and Technology Committee.

5.4 Reliability Guideline: ACE Diversity Interchange

The RSC Members reviewed the Reliability Guideline ACE Diversity Interchange redline containing proposed revisions. ISO-NE will provide comments and the RSC agreed to review the comment form for ACE Diversity Interchange provided by Kathleen Goodman. The RSC Members will provide additional comments in addition

to the comments provided by Kathleen Goodman and will finalize and submit comments as a group.

5.5 Standard Grading

Guy Zito gave a status update on the Standard Grading effort. The TPL and FAC standards are likely to be reviewed next year by a group of industry experts. They are noted by NERC staff and there are concerns from the industry.

5.6 GMD Presentation

Guy Zito gave a presentation on GMD. Payam Farahbakhsh had a concern about the 85A threshold for transformer GIC current. According to Mr. Farahbakhsh, the threshold should consider the age of the transformer and other criteria (heating. The threshold might be lower than 85A and the approach is not risk based.

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	8/23/17 Call-In
Project 2013-03 Geomagnetic Disturbance Mitigation TPL-007-2	8/11/17 (F)	8/11/17 (I)	Scott Barfield-McGinnis	1:00PM
Project 2016-04 Modifications to PRC-025-1	9/7/17 (F)	9/7/17 (I)	Scott Barfield-McGinnis	1:15PM
Project 2015-10 Single Points of Failure TPL-001	5/24/17 (I)		Latrice Harkness	1:30PM
Revisions to the NERC Standard Processes Manual	5/3/17 (F)	5/3/17 (I)	Chris Larson	1:45PM
Project 2017-01 Modifications to BAL-003-1.1	7/18/17 (F)		Darrel Richardson	2:00PM
Project 2017-02 Modifications to Personnel Performance, Training, and Qualifications Standards	7/24/17 (I)		Darrel Richardson	2:15PM
Project 2017-06 Modifications to BAL-002-2	7/20/17 (I)		Darrel Richardson	2:30PM
Project 2015-09 Establish and Communicate System Operating Limits	8/12/16 (I)		Darrel Richardson	2:45PM
Project 2017-05 NUC-001-3 Periodic Review			Mat Bunch	3:00PM
Project 2016-02 Modifications to CIP Standards CIP-012-1	9/11/17 (F)	9/11/17 (I)	Katherine Street Mat Bunch	3:15PM
2018-2020 Reliability Standards Development Plan	7/25/17 (F)		Sean Cavote	3:30PM
Project 2017-03 FAC-008-3 Periodic Review			Al McMeekin	3:45PM
2017 Periodic Review Standing Review Team - Standards Grading	8/2/17 (I)		Laura Anderson	4:00PM
Project 2017-04 Periodic Review of Interchange Scheduling and Coordination Standards			Laura Anderson	4:15PM
Comments: (I) – Informal; (F) – Formal; (N) – Nomination Period **Ballots:** (I) – Initial; (A) – Additional; (F) – Final				

Project 2013-03 Geomagnetic Disturbance Mitigation TPL-007-2:
Scott Barfield called in at 1PM and pointed out the initial ballot of the standard has passed.
The SDT is reconvening next week at PJM to respond to the comments.
Their goal is to do a second posting sometime in September 2017 in order to answer comments and submit for the final ballot by December.
There is some confusion regarding the implementation date since there is no reference date to the old version of the implementation plan.
The Canadian entities have some cost concerns regarding the additional assessments.

Project 2016-04 Modifications to PRC-025-1:
The project is posted for comment and ballot.
One of the key issue is finding an alternative for relay loadability.
The SDT did not receive a lot of comments on the SAR.

Project 2015-10 Single Points of Failure TPL-001:
Two FERC Orders related to this project, one specific on Single Point of Failure, the other Order directed NERC to consider short term outages in the planning process.
Chris Larson filled in for Latrice Harkness from NERC.
The Project is on the September 2017 SC agenda for approval to post.
The goal is to post the project on September 7, 2017 or the following week.

Revisions to the NERC Standard Processes Manual:
Chris Larson called in at 1:35PM.
The Standard Committee Process Subcommittee (SCPS) subgroup is reviewing the comments/changes to the redline.
At this time, there is no date available for a second posting.
Section 5 and 7 were modified however there were a lot of push back by the industry on the changes to section 7 and they were reinstated.
Section 11 has also been updated.

Project 2017-01 Modifications to BAL-003-1.1:
Darrel Richardson called in at 2PM.
The SAR was posted from mid-June to mid-July.
The SC was requested to re-open the nomination period for the drafting team since they are looking for more variety of industry experts.
Approval of the drafting team members will be on the September 2017 SC agenda.

Project 2017-02 Modifications to Personnel Performance, Training and Qualifications Standards:
The SAR was posted for comment until July 24, 2017.
The SDT recommended to retire PER-004 and make slight modifications to PER-003 (footnote edits).
Darrel Richardson expects the project to move forward rather quickly.

Project 2017-06 Modifications to BAL-002-2:
A SAR is posted to consider revising BAL-002-2 to respond to two FERC directives.

The SC has been requested to approve soliciting for drafting team members.

Project 2015-09 Establish and Communicate System Operating Limits:
This project is on the September 2017 SC meeting agenda to approve posting.
There will be a 45-day comment period with a concurrent 10-day ballot at the conclusion of the 45-day comment period.
There will also be an informal comment period to revise the SOL and SOL exceedance definition.
There were some proposed changes to the SOL definitions since the posting of 2016 and the drafting team needs to find out if the SOL definition needs additional changes since the posting of 2016.

Project 2017-05 NUC-001-3 Periodic Review:
Mat Bunch called in at 3PM and indicated that they have just begun working on this Project.
The standing review team is scheduled to meet on September 12 and 13.

Project 2016-02 Modifications to CIP Standards CIP-012-1:
Katherine Street called in with Mat Bunch at 3:10PM.
The SDT just had a webinar on the current posting.
Ballot pool is opened until August 25, 2017.
Formal comment period will end on September 11, 2017.
RSAW was posted on August 17, 2017.
Technical and Rationale document has also been posted.
Control Center definition has also been posted for an informal comment period.
An informal comment period is also expected for the proposed Glossary Term Virtualization.

2018-2020 Reliability Standards Development Plan:
This project will also reflect all the changes from prior years.
The focus continues to be the upcoming standards and development activities.
This version of the RSDP does not include the timeline and resources needed for the individual projects, only a good faith estimation was included.

Project 2017-03 FAC-008-3 Periodic Review:
This is one of the standards graded last year that received a low score.
The project opened for solicitation of drafting team members until May 23, 2017.

Project 2017 Periodic Review Standing Review Team – Standard Grading:
Laura Anderson called in at 3:58PM and gave a brief update on Standard Grading project.
The team met yesterday August 22, 2017 at Atlanta GA NERC Office to finalize the standards development plan.
The first public meeting was held in June, 2017.
The first comment period was concluded early August 2017.

Project 2017-04 Periodic Review of Interchange Scheduling and Coordination Standards:
The training started yesterday August 22, 2017.

The team is looking at the standards and trying to formulate the standard into the periodic review template.
The team kicked off the project today August 23, 2017.
The team is planning to produce a draft timeline in their next meeting.

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

7.0 NERC Drafting Team Nominations

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

8.0 NPCC Regional Reliability Standards
https://www.npcc.org/Standards/default.aspx

8.1 Current Activities:

8.1.1 RSC approval required for the posting of Automatic Underfrequency Load Shedding PRC-006-NPCC-02 draft redline

Approval to post—Automatic Underfrequency Load Shedding PRC-006-NPCC-02 draft redline.

Herb Schrayshuen made a motion for approval.

Brian Robinson seconded the motion.

Automatic Underfrequency Load Shedding PRC-006-NPCC-02 draft redline is approved for posting.

8.1.1..1 Provide target dates/schedule to RSC

Ruida Shu provided a summary of target dates/schedule to the members of RSC.

8.1.1..2 Officially appoint Brian Robinson as the liaison between the RSC and PRC-006-NPCC-02 drafting team

Herb Schrayshuen made a motion for approval.

Payam Farahbakhsh seconded the motion.

Brian Robinson is officially approved as the liaison between the RSC and PRC-006-NPCC-02 drafting team.

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

Ruida Shu and Guy Zito provided a status update to the members of RSC.

PRC-006-3 Automatic UFLS Quebec Variance is approved by the NERC BOT and it is pending approval by the Regie.

Informational filing is being prepared for FERC.

9.0 NPCC Non-Standards

Mr. Dunbar updated the RSC on the status of various Directories and other Criteria Services initiatives:

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

9.1 Directories:

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

The TFCO has approved a version of Directory#8 which has been revised by the CO-11 Restoration Working Group. The Directory was revised to remove duplicate battery testing requirements with PRC -005 and to reformat the criteria into NERC style requirements. ~~TFCO and Critical Component and Key Facilities).~~ The revised version of Directory 8 was posted to the Open Process for three comment postings and the revised Directory is on the September RCC agenda for approval.

9.1.2 Directory#9 and #10 *Real and Reactive Capability Verification*

The NPCC Full Member Committee voted to retire Directories #9 and #10 effective July 1st, 2019 to coincide with the 100% date implementation date of MOD-025-2. The existing TOP Verification program as contained in D#9 and D#10 will continue to be monitored by the NPCC Compliance Committee until Directories #9 and #10 are formally retired.

Formatted: List Paragraph

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

The TFCP and its CP-11 Working Group are developing are considering methodologies to identify a set of critical facilities within NPCC which would be subject to NPCC's more stringent criteria.

Currently CP-11 is refining the existing A-10 methodology to achieve more consistent implementation and outcomes; concurrently the CP-11 is also researching alternative methodologies.

9.1.4 A-01 *Criteria for Review and Approval of Documents* – (RSC to consider incorporating document A-01 into the Directory review and Revision Manual).

Revisions to the A-01 document were recently approved by the NPCC Full Member Committee.

Currently, a sub –group of the RSC is drafting revisions to the NPCC Directory Manual which would incorporate the A-01 content into the Directory Manual for the purposes of retiring the A-01.

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

The TFCO and its Working Groups the CO-1 and CO-8 have undertaken a review of Directories #2 and #5 in order to reformat the criteria in both Directories into NERC style requirements and also to review the criteria to eliminate any duplicity with recently approved NERC Standards (D#5 = BAL-002-02). Both reviews are pending an initial posting.

9.1.6 Directory#4 System Protection Criteria – (status of Eversource Clarification Request)

The TFSP has rendered a Clarification on the criteria in Directory #4 on behalf of Eversource Energy.

The clarification provides guidance on the installation of trip coil monitoring devices and is posted for comment until September 22.

.

9.2 Other:

RAS Implementation:

The TFCP is coordinating a regional transition to the approved NERC Glossary Term Remedial Action Scheme (RAS).

The NPCC SPS list has been organized to reflect those SPS's that conform to the revised definition, those that do not conform and those protection systems not previously identified as a SPS but which now conform to the definition.

Currently, the TFSS is evaluating a TFCP request to consider the reliability impact of removing those SPS's from the NPCC list that do not conform to the definition.

PRC-012-2 has been approved by the NERC BOT and is pending regulatory approval.

ISO-NE Request:

The RSC discussed the ISO-NE request to retire the NPCC Criteria and the response of the NPCC.

10.0 RSC Member Items of Interest

10.1 RSC Roster

The members of RSC reviewed the roster together and Chantal Mazza from HQ requested to be swapped with Si-Truc Phan on the roster from secondary to primary.

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 18th - Call	March 15th - Meeting	April 19th - Call
June 14th - Meeting	July 19th - Call	September 7th Meeting
October 18th - Call	December 6th - Meeting	

SC 2018 Schedule:

January 17th - Call	March 14th - Meeting	April 18th - Call
June 13th - Meeting	July 25th - Call	September 12th Meeting
October 17th - Call	December 5th - 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

January 4th - Call	February 21st - Call	March 14th – Meeting
March 29th – Call	May 22nd - Call	June 13th – Meeting
June 28th – Call	August 18th – Call	September 6th – Meeting
September 28th – Call	November 14th – Call	December 5th - Meeting

SCPS 2018 Schedule:

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

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

January 26th - Call	March 15th - Meeting	April 27th - Call
June 14th - Meeting	July 27th - Call	September 7th Meeting
October 12th - Call	December 6th - Meeting	

PMOS 2018 Schedule:

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

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

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

February 8-9 - Meeting	May 10-11 - Meeting	August 9-10 - Meeting
November 7-8 - Meeting		

BOT 2018 Schedule:

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

12.6 Reliability Issues Steering Committee (RISC)
http://www.nerc.com/comm/RISC/Related%20Files%20DL/ERO_Reliability_Risk_Priorities_RISC_Reccommendations_Board_Approved_Nov_2016.pdf

13.0 NERC Items of Interest (Since last RSC Meeting)

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

13.1.1 There have been two 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 three new NERC Alerts released since the last RSC meeting.

13.3 Final NERC 2018 Business Plan and Budget

13.4 Proposed Additional Resolutions for Cyber Security – Supply Chain Risk Management

14.0 Other Items of Interest

14.1 NPCC Compliance Committee (CC) Schedule

January 18th – Call	February 15th – Call	March 14-15th Meeting
April 12th – Call	May 23-25th Workshop	June 13-14th Meeting
July 12th – Call	August 16th – Call	September 19-20th Meeting
October 18th – Call	November 7-9th Workshop	December 7th Meeting

14.2 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

NPCC Board of Directors Meeting (BOD) 2018

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

14.3 NPCC Business Plan and Budget 2018

15.0 Future RSC Meetings and Conference Calls

15.1 RSC 2017 Meeting Dates

March 8th-9th, FRCC, Tampa FL
June 7th-8th, Saratoga NY
August 23rd-24th, Toronto
October 11th-12th, Lewiston NY
December 7th, Boston MA

15.2 RSC 2017 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 20	February 3	February 17
March 24	April 7	April 21
May 5	May 19	June 16
June 30	July 14	July 28
August 11	September 8	September 22
September 29	October 27	November 10
November 24	December 22	

15.3 Tentative RSC 2018 Meeting Dates

February/March, NextEra/FRCC, Juno Beach/Tampa FL
June 6-7, 2018 Saratoga NY Subject to Approval
August 29-30, 2018 Toronto Subject to Approval
October 10-11, 2018 Lewiston NY/Boston Mass Avenue NStar Location Subject to Approval
December, Toronto ON

The meeting is adjourned at 9:54AM on August 24, 2017.

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
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
2013-03	Geomagnetic Disturbance Mitigation	Standard	Per-Anders Lof Rui Sun	National Grid Dominion	781-907-5581	per-anders.lof@nationalgrid.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		
2015-09	Establish and Communicate System Operating Limits - FAC-010, FAC-011, FAC-014	Standard	Dean Laforest Sam Jager	ISO-NE IESO		
2015-10	Single Points of Failure - TPL-001	Standard	Ovidiu Vasilachi Rich Kowalski	IESO Observer ISO-NE		
2016-01	Modifications to TOP and IRO Standards - TOP-001, IRO-002	Standard				
2016-02	Modification to CIP Standards	Standard	Steve Brain 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	Juan Alvarez	Utility Services		
2016-EPR-01	Enhanced Periodic Review of Personnel Performance, Training, and Qualifications Standards	Standard	Tim Kucey	PSEG Fossil, LLC		
2017-01	Modifications to BAL-003-1.1	Standard				
2017-02	Modifications to Personnel Performance, Training, and Qualifications Standards - PER-003, PER-004	Standard				
2017-06	Modifications to BAL-002-2	Standard				
2017-07	Standards Alignment with Registration	Standard				

Source = NERC Standard Drafting Team Rosters - September 2016

NPCC Document Open Process Executive Tracking Summary

Revised: **9/22/2017** 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	Guideline	B-01	NPCC Guide for the Application of Autoreclosing to the Bulk Power System	Feb-13	Comment Period Open Until 10/30.	TFSP posted to Open Process for 2nd Open Process Comment Period.
2	Directory Clarification	Directory #4	System Protection Criteria	N/A	Comment Period Concluded 9/22.	Pending TFSP Comment Review and RCC Approval.
3	Regional Standard	PRC -006-NPCC-1	Automatic UFLS	Feb-12	Comment Period Concluded 10/16.	Drafting Team to Consider Open Process Comments.
4	Directory	Directory#2	Emergency Operation	Jun-09	Comment Period Anticipated October 2017.	CO-8 Working Group to Request TFCO Permission to Post at TFCO October Mtg.

NPCC Directory Executive Tracking Summary

Revised: 9/22/2017 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	Comment Period Anticipated October 2017.	CO-8 Working Group to Request TFCO Permission to Post at TFCO October Mtg.
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		TFCO Working Group CO-1 reviewing reformatted draft of Directory#5.
6	Directory #6		Regional Reserve Sharing		Apr-12		
7	Directory #7	Criteria A-11	Special Protection Systems	TFSP	Jul-13		Pending approval of PRC-012-2 TFSP and TFSS to consider review of Directory#7 criteria and NPCC Glossary definition of SPS.
8	Directory #8	Criteria A-12	System Restoration	TFCO	Oct-10	Full Member Ballot to Conclude on October 6th, 2017.	Pending Full Member Approval of TFCO Revisions.
9	Directory #9	Criteria A-13	Verification of Generator Gross and Net Real Power Capability	TFCO	Dec-11		NPCC Full Members approved retirement of D#9 and D#10 pending full enforcement of MOD-25-2. (July 2019).
10	Directory #10	Criteria A-14	Verification of Generator Gross and Net Reactive Power Capability	TFCO	Dec-11		See D#9.
11	Directory#11	Criteria A-15	Disturbance Monitoring	TFSP	Oct-16	D#11 Approved October 2016.	
12	Directory#12		UFLS	TFSS	Oct-12		

NPCC Directory Criteria Clarifications

Revised: 9/22/2017 Further details regarding the individual documents may be found at: https://www.npcc.org/Standards/Directory%20Interpretations/Forms/Public%20List.aspx

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

9/22/2017

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

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

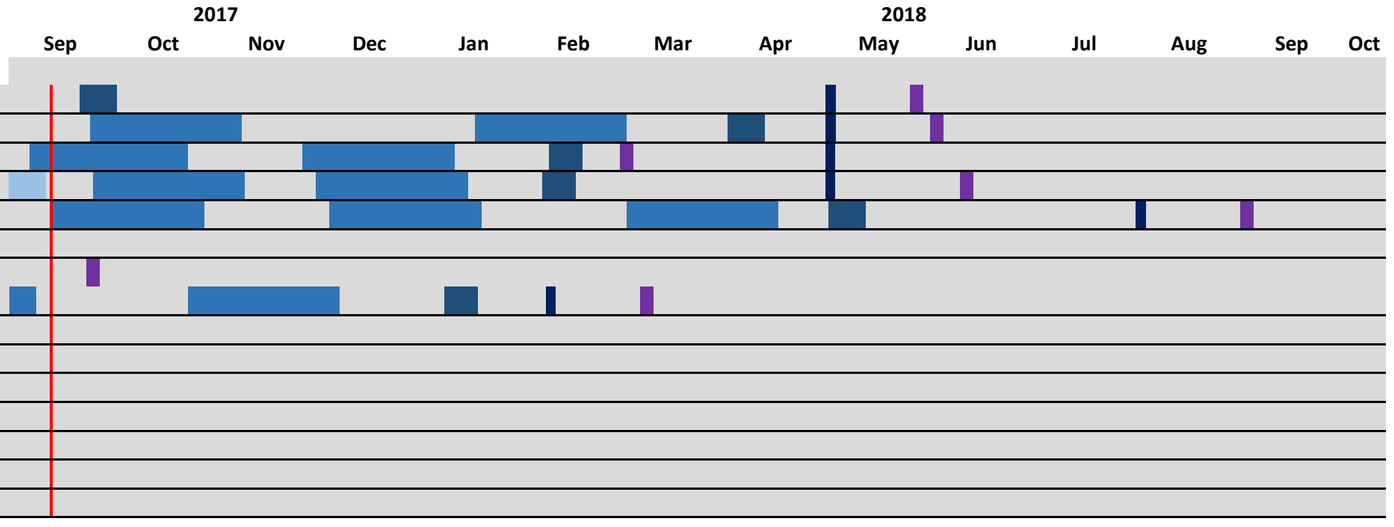
SUMMARY
Tutorial Video (11 min)
Click here to report errors or issues

Updated: 9/13/2017

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

HOME

U	Project (Filter)	Deliverables (Filter)	Early/(Late) Days (Filter)	Baseline/ Current (Filter)
Ye	2013-03 - Geomagnetic Disturbance Mitigation	TPL-007-2	151	Current
Ye	2015-09 - Establish and Communicate System (	FAC-010-3, FAC-011-3, and FAC		Current
Ye	2015-10 - Single Points of Failure TPL-001	TPL-001-5	(31)	Current
Re	2016-02 - Modifications to CIP Standards	Directives, Control Center Com	(112)	Current
Ye	2016-02 - Modifications to CIP Standards	Address TO Control Centers Pe	(197)	Current
Re	2016-02 - Modifications to CIP Standards	Address all remaining V5TAG is		N/A
Ye	2016-03 - Cyber Security Supply Chain Manage	New and revised Standard(s)	(20)	Current
Ye	2016-04 - Modifications to PRC-025-1	PRC-025-2		Current
Ye	2017-01 - Modifications to BAL-003-1	BAL-003-2		Proposed
Ye	2017-02 - Modifications to Personnel Performa	PER-003-2, retire PER-004-2		Proposed
Ye	2017-03 - Periodic Review of FAC-008-3 Standa	Periodic Review Recommendat		N/A
Ye	2017-04 - Periodic Review of Interchange Sche	Periodic Review Recommendat		N/A
Ye	2017-05 - Project 2017-05 NUC-001-3 Periodic	Periodic Review of NUC-001-3		N/A
Ye	2017-06 - Project 2017-06 Modifications to BAI	BAL-002-3		Proposed
Ye	2017-07 - Standards Alignment with Registratic			Proposed



Project Name	Status	Comments	Deliverable	Deadline	Priority in RSDP, click to see applicable	P81 Req (2013)	Number of Directives	No. of Guidances (see Note 2)	Directionally consistent with IERP findings (See Note 5)	Developer	PMOS Liaison	Affected Standards	Last Updated
(Sorting okay)	(Sorting okay)	(Sorting okay)	(Sorting okay)	(Sorting okay)	(Sorting okay)	(Sorting okay)	(Sorting okay)	(Sorting okay)	(Sorting okay)	(Sorting okay)	(Sorting okay)	(Sorting okay)	HOME
Geomagnetic Disturbance Mitigation	Responding to Comment	FERC issued Order No. 830 on September 22, 2016 approving TPL-007-1 and directing modifications. The SDT will develop revised or new requirements to enhance the benchmark GMD event used in	TPL-007-2	5/29/2018	Footnote 8, High	N/A	4	N/A	N/A	Mark Olson	Jennifer Sterling	TPL-007-1	9/5/2017
Establish and Communicate System Operating Limits	Working to Initial Ballot	The team anticipates requesting authorization to post for 45-day comment period and initial ballot at the September 2017 SC meeting. The team anticipates posting for formal comment and initial ballot	FAC-010-3, FAC-011-3, and FAC-014-2	N/A	Footnote 7, Medium	N/A	N/A	N/A	N/A	Darrel Richardson & Al McMeekin	Ken Lanehome	FAC-010-3, FAC-011-3, and FAC-014-2	9/5/2017
Single Points of Failure TPL-001	Working to Initial Ballot	The team anticipates SC approval to post on September 7, 2017. The standard will be posted on or after September 7, 2017 pending SC authorization for a 45-day formal comment and initial ballot period.	TPL-001-5	N/A	Footnote 8, High	N/A	2 directives at P40 & P89 (Click this link	N/A	N/A	Latrice Harkness	Mark Pratt	TPL-001-4	9/5/2017
Modifications to CIP Standards	Responding to Comment	Two concurrent 29-day informal comment periods ended April 11, 2017, for stakeholders to provide feedback on the Standard Drafting Team's (SDT's) approaches to addressing two issues from the Version	Address all remaining V5TAG issues: Cyber Asset and BES CA	N/A	Footnote 8, High	N/A	N/A	N/A	N/A	Mat Bunch & Katherine Street	Ken Lanehome and Ash	CIP Stds. - Unknown	8/25/2017
Modifications to CIP Standards	Posted	The team did not present to the SC authorizing the standard for initial balloting on July 19, 2017 and instead posted for a 30-day informal comment period ending September 11, 2017.	Directives, Control Center Comm Nets (CIP-012-1)	N/A	Footnote 8, High	N/A	2	N/A	N/A	Mat Bunch & Katherine Street	Ken Lanehome and Ash		8/14/2017
Modifications to CIP Standards	Responding to Comment	Two concurrent 29-day informal comment periods ended April 11, 2017, for stakeholders to provide feedback on the Standard Drafting Team's (SDT's) approaches to addressing two issues from the Version	Address TO Control Centers Performing Transmission	N/A	Footnote 8, High	N/A	N/A	N/A	N/A	Mat Bunch & Katherine Street	Ken Lanehome and Ash	CIP Stds. - Unknown	9/5/2017

Project	**2013-03**
Project Name	Geomagnetic Disturbance Mitigation
Status	Responding to Comment
Comments	FERC issued Order No. 830 on September 22, 2016 approving TPL-007-1 and directing modifications. The SDT will develop revised or new requirements to enhance the benchmark GMD event used in GMD assessments, require collection of GMD data, and establish deadlines for GMD Corrective Action Plans and mitigation measures. Revisions must be filed by May 29, 2018. The SAR was accepted by the Standards Committee on March 15, 2017. The team met at PJM August 29-31, 2017. No substantive changes were made, the team is proposing to go out for final ballot at the end of September.
Deliverable	TPL-007-2
Deadline	**Tuesday, May 29, 2018**
Priority in RSDP, click to see applicable Footnote	Footnote 8, High
P81 Req (2013)	N/A
Number of Directives	4
No. of Guidances (see Note 2)	N/A
Directionally consistent with IERP findings (See Note 5)	N/A
Developer	Mark Olson
PMOS Liaison	Jennifer Sterling
Affected Standards	TPL-007-1
Last Updated	9/5/2017

Home

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR	10/20/2016	11/9/2016	10/20/2016	11/9/2016			
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	12/16/2016	1/20/2017	12/20/2016	1/19/2017	4		
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							

CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	6/28/2017	8/11/2017	6/15/2017	7/30/2017	(13)		Passed
CAB - Com/Add Ballot 2			***9/11/2017***	***##########***			Changed from 9/11 to 9/22 to stagger 2013-03, 2015-09, and 2015-10.
CAB - Com/Add Ballot 3			11/29/2017	1/13/2018			
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	9/22/2017	10/2/2017	2/20/2018	3/2/2018	151		
PTB - Present to BOT	5/1/2018	5/3/2018	5/1/2018	5/3/2018			
Filing - Filing with Regulators	5/26/2018	5/29/2018	5/26/2018	**5/29/2018**			
PT - Post Approval Training							

PTS Change Control

Reason for Update	**Date**	**Notes**
No dates provided	6/1/2016	Project finished prior to 2015.
Accept Baseline Schedule	6/14/2017	Accepted by unamious consent.
Schedule Adjustment	8/10/2017	Changed from 9/11 to 9/22 to stagger 2013-03, 2015-09, and 2015-10.

Project	**2015-09**
Project Name	Establish and Communicate System Operating Limits
Status	Working to Initial Ballot
Comments	The team anticipates requesting authorization to post for 45-day comment period and initial ballot at the September 2017 SC meeting. The team anticipates posting for formal comment and initial ballot the week of September 25, 2017.
Deliverable	FAC-010-3, FAC-011-3, and FAC-014-2
Deadline	N/A
Priority in RSDP, click to see applicable Footnote	Footnote 7, Medium
P81 Req (2013)	N/A
Number of Directives	N/A
No. of Guidances (see Note 2)	N/A
Directionally consistent with IERP findings (See Note 5)	N/A
Developer	Darrel Richardson & Al McMeekin
PMOS Liaison	Ken Lanehome
Affected Standards	FAC-010-3, FAC-011-3, and FAC-014-2
Last Updated	9/5/2017

Home

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

CIB - Com/Ballot 1 (Initial)	***9/25/2017***	***11/8/2017***	9/22/2017	11/5/2017	(3)		Posting date changed see notes 8/10 and 8/25.
CAB - Com/Add Ballot 2	1/17/2018	3/2/2018	1/17/2018	3/2/2018			
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	4/2/2018	4/12/2018	4/2/2018	4/12/2018			
PTB - Present to BOT	5/1/2018	5/3/2018	5/1/2018	5/3/2018			
Filing - Filing with Regulators	6/1/2018	6/4/2018	6/1/2018	6/4/2018			
PT - Post Approval Training							

PTS Change Control

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

Project	**2015-10**
Project Name	Single Points of Failure TPL-001
Status	Working to Initial Ballot
Comments	The team anticipates SC approval to post on September 7, 2017. The standard will be posted on or after September 7, 2017 pending SC authorization for a 45-day formal comment and initial ballot period.
Deliverable	TPL-001-5
Deadline	N/A
Priority in RSDP, click to see applicable Footnote	Footnote 8, High
P81 Req (2013)	N/A
Number of Directives	2 directives at P40 & P89 (Click this link for FERC Order)
No. of Guidances (see Note 2)	N/A
Directionally consistent with IERP findings (See Note 5)	N/A
Developer	Latrice Harkness
PMOS Liaison	Mark Pratt
Affected Standards	TPL-001-4
Last Updated	9/5/2017

Home

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR	11/12/2015	12/1/2015	1/18/2016	2/1/2016	67		
Nominations - DT	7/22/2016	8/5/2016	7/25/2016	8/8/2016	3		
QR - Quality Review			5/30/2016	6/9/2016			
SP1 - SAR/PR/WP Posting 1	11/12/2015	12/17/2015	11/12/2015	12/17/2015			
SP2 - SAR/PR/WP Posting 2	5/26/2016	6/24/2016	6/15/2016	7/15/2016	20	Expanded Scope	
CP1 - Comment Period 1	4/25/2017	5/24/2017	4/25/2017	5/24/2017		Other	Team added informal comment period

CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	***9/7/2017***	***10/23/2017***	7/5/2017	8/18/2017	(64)		Held at 9/7 to stagger 2013-03 and 2015-09.
CAB - Com/Add Ballot 2	11/27/2017	1/10/2018	10/18/2017	12/1/2017	(40)		
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	2/8/2018	2/17/2018	1/8/2018	1/17/2018	(31)		
PTB - Present to BOT	5/1/2018	5/3/2018	2/1/2018	2/3/2018	(89)		
Filing - Filing with Regulators	3/1/2018	3/4/2018	3/1/2018	3/4/2018			
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Expansion of Scope	6/14/2016	FERC directives added (P40 & P89) additional scoping in addition to industry comments following the second SAR posting. The MOD references are being updated due to some retiring
Developer change	1/13/2017	Transition from Lacey Ourso to Soo Jin Kim until a new developer is assigned.
Accept Schedule	4/27/2017	Accepted by PMOS.
Schedule deviation	6/13/2017	Baseline initial ballot of 7/5/2017 moved to 9/7/2017 due addressing comments and scope of SAR. Schedule accounts for SC not meeting in August.
Schedule Adjustment	8/10/2017	No adjustment required 2013-03, 2015-09, and 2016-02 were staggered to spread postings out.

Project	**2016-02**
Project Name	Modifications to CIP Standards
Status	Posted
Comments	The team did not present to the SC authorizing the standard for initial balloting on July 19, 2017 and instead posted for a 30-day informal comment period ending September 11, 2017.
Deliverable	Directives, Control Center Comm Nets (CIP-012-1)
Deadline	N/A
Priority in RSDP, click to see applicable Footnote	Footnote 8, 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	Mat Bunch & Katherine Street
PMOS Liaison	Ken Lanehome and Ash Mayfield
Affected Standards	
Last Updated	8/14/2017

Home

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR							
Nominations - DT							
QR - Quality Review	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	2/10/2017	3/13/2017					
CP2 - Comment Period 2	8/14/2017	9/11/2017	12/2/2016	1/16/2017	(255)		Added informal commetn period
CIB - Com/Ballot 1 (Initial)	***9/26/2017***	***11/9/2017***	3/31/2017	5/15/2017	(179)		

CAB - Com/Add Ballot 2	12/1/2017	1/14/2018	8/15/2017	9/29/2017	(108)		
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	2/6/2018	2/15/2018	10/17/2017	10/27/2017	(112)		
PTB - Present to BOT	5/1/2018	5/3/2018	11/7/2017	11/9/2017	(175)		
Filing - Filing with Regulators	6/10/2018	6/13/2018	12/28/2017	12/31/2017	(164)		
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Archived comments	6/10/2016	Order 822 was issued on January 21, 2016. The SC authorized posting the SAR and to request nominations for additional team members at March 9, 2016 meeting. The SAR posting ended April 21, 2016 and the SDT is reviewing the comments received. A CIP Technical Conference was held on April 19, 2016 in Atlanta. Seven additional members were appointed to the SDT at the April 20, 2016 SC meeting. Initial SDT meeting May 24-26, 2016 in Atlanta.
Added CIP Schedule for approval	7/20/2016	Update SC that schedule was approved by SDT, SDT leadership, developer, and PMOS Liaison.
Liaison Change	3/15/2017	Updated B. Murpy and A. Gallow to K. Lanehome and A. Mayfield
Developer Change	4/1/2017	Replaced Al McMeekin with Mat Bunch and Katherine Street.
Change in Approach	6/27/2017	Team decided to create CIP-012-1 and not modiifying CIP-006 for Communcation Networks.

Project	**2016-02**
Project Name	Modifications to CIP Standards
Status	Responding to Comment
Comments	Two concurrent 29-day informal comment periods ended April 11, 2017, for stakeholders to provide feedback on the Standard Drafting Team's (SDT's) approaches to addressing two issues from the Version 5 Transition Advisory Group (V5TAG): (1) the applicability of the CIP Reliability Standards to BES Cyber Systems for a Transmission Owner Control Center performing the functional obligations of a Transmission Operator. The team anticipates posting for a formal comment period and initial ballot the week of September 11, 2017
Deliverable	Address TO Control Centers Performing Transmission Operator (TOP) Obligations.
Deadline	N/A
Priority in RSDP, click to see applicable Footnote	Footnote 8, High
P81 Req (2013)	N/A
Number of Directives	N/A
No. of Guidances (see Note 2)	N/A
Directionally consistent with IERP findings (See Note 5)	N/A
Developer	Mat Bunch & Katherine Street
PMOS	Ken Lanehome and Ash Mayfield
Affected Standards	CIP Stds. - Unknown
Affected Standards	9/5/2017

Home

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

CP1 - Comment Period 1	3/14/2017	4/11/2017					Added to schedule, reduced period - SDT needed feedback
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	***9/14/2017***	***10/28/2017***	12/2/2016	1/15/2017	(286)		See notes for 8/10 and 8/25.
CAB - Com/Add Ballot 2	12/5/2017	1/18/2018	3/31/2017	5/14/2017	(249)		
CAB - Com/Add Ballot 3	3/3/2018	4/16/2018	8/15/2017	9/28/2017	(200)		
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	5/2/2018	5/12/2018	10/17/2017	10/27/2017	(197)		
PTB - Present to BOT	8/1/2018	8/3/2018	11/7/2017	11/9/2017	(267)		
Filing - Filing with Regulators	9/1/2018	9/4/2018	12/28/2017	12/31/2017	(247)		
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Archived comments	6/10/2016	Order 822 was issued on January 21, 2016. The SC authorized posting the SAR and to request nominations for additional team members at March 9, 2016 meeting. The SAR posting ended April 21, 2016 and the SDT is reviewing the comments received. A CIP Technical Conference was held on April 19, 2016 in Atlanta. Seven additional members were appointed to the SDT at the April 20, 2016 SC meeting. Initial SDT meeting May 24-26, 2016 in Atlanta.
Added CIP Schedule for approval	7/20/2016	Update SC that schedule was approved by SDT, SDT leadership, developer, and PMOS Liaison.
Liaison Change	3/15/2017	Updated B. Murpy and A. Gallow to K. Lanehome and A. Mayfield
Developer Change	4/1/2017	Replaced Al McMeekin with Mat Bunch and Katherine Street.
Schedule Adjustment	8/10/2017	The original 5/15/2017 planned posting was accepted for 9/18 to stagger 2013-03, 2015-09, and 2015-10.

Schedule Adjustment	8/25/2017	The posting was advanced due to 2015-09 (SOL) being moved from its 9/12 posting to 9/30.

Project	**2016-02**	**Home**
Project Name	Modifications to CIP Standards	
Status	Responding to Comment	
Comments	Two concurrent 29-day informal comment periods ended April 11, 2017, for stakeholders to provide feedback on the Standard Drafting Team's (SDT's) approaches to addressing two issues from the Version 5 Transition Advisory Group (V5TAG): **the use of virtualization in the CIP environment.**	
Deliverable	Address all remaining V5TAG issues: Cyber Asset and BES CA (BCA) definitions, Network and Externally Accessible Devices (ESP, ERC, IRA), Obligations, Virtualization, and CIP Exceptional Circumstances.	
Deadline	N/A	
Priority in RSDP, click to see applicable Footnote	Footnote 8, High	
P81 Req (2013)	N/A	
Number of Directives	N/A	
No. of Guidances (see Note 2)	N/A	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Mat Bunch & Katherine Street	
PMOS Liaison	Ken Lanehome and Ash Mayfield	
Affected Standards	CIP Stds. - Unknown	
Last Updated	8/25/2017	

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR							
Nominations - DT							
QR - Quality Review	10/20/2016	10/30/2016	10/20/2016	10/30/2016			
SP1 - SAR/PR/WP Posting 1							
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1	3/14/2017	4/11/2017	3/14/2017	4/11/2017			
CP2 - Comment Period 2							

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

PTS Change Control

Reason for Update	Date	Notes
Segmented project	8/8/2017	This fourth segment of the project was made to address all remaining V5TAG issues: Cyber Asset and BES CA (BCA) definitions, Network and Externally Accessible Devices (ESP, ERC, IRA), Obligations, Virtualization, and CIP Exceptional Circumstances.

Project	**2016-03**
Project Name	Cyber Security Supply Chain Management
Status	Pending Regulatory Filing
Comments	All three standards passed overwhelmingly. The team met on June 21 & 22, 2017 and decided to post for final ballot. Standard was adopted by the NERC Board August 10, 2017. NERC staff are preparing to file with governmental authorities.
Deliverable	New and revised Standard(s)
Deadline	**Wednesday, September 27, 2017**
Priority in RSDP, click to see applicable Footnote	Footnote 8, 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	Mark Olson
PMOS Liaison	Brenda Hampton
Affected Standards	CIP-005-6, CIP-010-3, and CIP-013-1
Last Updated	9/5/2017

Home

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR							
Nominations - DT	7/29/2016	8/18/2016	7/29/2016	8/18/2016			
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	10/20/2016	11/18/2016	10/20/2016	11/21/2016			
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	1/19/2017	3/6/2017	1/19/2017	3/6/2017			

CAB - Com/Add Ballot 2	5/2/2017	6/15/2017	4/12/2017	5/26/2017	(20)		CIP-005-6 89.84% CIP-010-3 82.92% CIP-013-1 88.64%
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	7/11/2017	7/20/2017	6/21/2017	6/30/2017	(20)		CIP-005-6 88.79% CIP-010-3 81.40% CIP-013-1 884.19%
PTB - Present to BOT	8/9/2017	8/11/2017	8/9/2017	8/11/2017			
Filing - Filing with Regulators	9/24/2017	9/27/2017	9/24/2017	**9/27/2017**			
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Create project record	8/1/2016	Added project to PTS.
Periodic Update	8/21/2016	Added FERC deadline.
Baseline Schedule	11/30/2016	SDT determined the schedule.
Present Schedule to SC	3/15/2017	Accepted the SDT project schedule.
Removed Liaison	4/14/2017	Removed R. Kinard due to resigning from PMOS.
Removed Liaison	7/27/2017	A. Kimmey due to leaving company.
Archive Project	TBD	

Project	**2016-04**	**Home**
Project Name	Modifications to PRC-025-1	
Status	Posted	
Comments	The standard is currently posted through September 7, 2017. The team will meet at NERC HQ on September 26-28, see the NERC calendar for details. Enhancements to 025 affects entities currently implementing version 1 under the five and seven year implementation period. The first period ends October 1, 2019 and the second on October 1, 2021. Project must consider the time for development and subsequent regulatory approvals.	
Deliverable	PRC-025-2	
Deadline	N/A	
Priority in RSDP, click to see applicable Footnote	Footnote 9, 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)	Yes	
Developer	Scott Barfield-McGinnis	
PMOS Liaison	Charles Yeung	
Affected Standards	PRC-025-1	
Last Updated	9/5/2017	

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR	9/16/2016	9/28/2016	9/16/2016	9/28/2016			
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	9/16/2016	10/18/2016	9/16/2016	10/18/2016			
SP2 - SAR/PR/WP Posting 2	3/20/2017	4/3/2017	3/2/2017	4/1/2017	(18)		
CP1 - Comment Period 1							
CP2 - Comment Period 2							

CIB - Com/Ballot 1 (Initial)	7/25/2017	9/7/2017	7/26/2017	9/8/2017	1		
CAB - Com/Add Ballot 2	10/17/2017	11/30/2017	10/24/2017	12/7/2017	7		
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	1/8/2018	1/17/2018	1/8/2018	1/17/2018			
PTB - Present to BOT	2/7/2018	2/9/2018	2/7/2018	2/9/2018			
Filing - Filing with Regulators	3/7/2018	3/10/2018	3/7/2018	3/10/2018			
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
SC Authorized Posting	9/14/2016	SAR and SAR SDT nominations.
Accept Baseline Schedule	7/27/2017	Accepted by PMOS.

Project	**2017-01**	**Home**
Project Name	Modifications to BAL-003-1	
Status	Nominations & SAR	
Comments	The project is seeking additional nominations to supplement the drafting team through August 9, 2017. Anticipate team member appointments in October.	
Deliverable	BAL-003-2	
Deadline	N/A	
Priority in RSDP, click to see applicable Footnote	Footnote 8, Medium	
P81 Req (2013)	N/A	
Number of Directives	N/A	
No. of Guidances (see Note 2)	N/A	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Darrel Richardson	
PMOS Liaison	Amy Casuscelli	
Affected Standards	BAL-003-1	
Last Updated	9/5/2017	

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR	6/19/2017	7/3/2017	6/19/2017	7/3/2017			
Nominations - DT	7/27/2017	8/9/2017	7/27/2017	8/9/2017			Supplemental Nominations
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	6/19/2017	7/18/2017	6/19/2017	7/18/2017			
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
Created Project in PTS	5/10/2017	Created Project record.
Assign PMOS Liaison	6/14/2017	Amy Casuscelli accepted appointment as PMOS liaison.

Project	**2017-02**	**Home**
Project Name	Modifications to Personnel Performance, Training, and Qualifications Standards	
Status	Working to Comment Posting	
Comments	Project was activated by the Standards Committee on June 14, 2017. The SAR is posted for a 30-day comment period. The team planned to meet August 29 and 30, 2017 in Houston, but due to Hurrican Harvey, the meeting was rescheduled for the end of September 2017.	
Deliverable	PER-003-2, retire PER-004-2	
Deadline	N/A	
Priority in RSDP, click to see applicable Footnote	Footnote 8, Medium	
P81 Req (2013)	N/A	
Number of Directives	N/A	
No. of Guidances (see Note 2)	N/A	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Darrel Richardson	
PMOS Liaison	Mike Brytowski	
Affected Standards	PER-003-1 & PER-004-2	
Last Updated	9/5/2017	

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR							EPR SDT appointed as SDT
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	6/21/2017	7/24/2017	6/21/2017	7/24/2017			
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)							

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

PTS Change Control

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

Project	**2017-03**	**Home**
Project Name	Periodic Review of FAC-008-3 Standard	
Status	Working to Comment Posting	
Comments	The team had their first meeting August 23-24, 2017 in Atlanta at NERC. Next in-person meeting is September 25, 2017.	
Deliverable	Periodic Review Recommendations	
Deadline	N/A	
Priority in RSDP, click to see applicable Footnote	Footnote 9, Low (was Medium previously)	
P81 Req (2013)	N/A	
Number of Directives	N/A	
No. of Guidances (see Note 2)	N/A	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Al McMeekin	
PMOS Liaison	Mark Pratt	
Affected Standards	FAC-008-3	
Last Updated	9/5/2017	

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR	5/10/2017	5/23/2017	5/10/2017	5/23/2017			
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1							
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)							
CAB - Com/Add Ballot 2							
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							

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

PTS Change Control

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

Project	**2017-04**	**Home**
Project Name	Periodic Review of Interchange Scheduling and Coordination Standards	
Status	Working to Comment Posting	
Comments	The team had their first meeting August 23-24, 2017 in Atlanta at NERC and will have a follow up meeting September 26-27, 2017 at Xcel in Denver.	
Deliverable	Periodic Review Recommendations	
Deadline	N/A	
Priority in RSDP, click to see applicable Footnote	Footnote 9, Low (was Medium previously)	
P81 Req (2013)	N/A	
Number of Directives	N/A	
No. of Guidances (see Note 2)	N/A	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Laura Anderson	
PMOS Liaison	Charles Yeung	
Affected Standards	INT-004, INT-006, INT-009, and INT-010	
Last Updated	9/13/2017	

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR	5/2/2017	5/15/2017	5/2/2017	5/15/2017			
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1							
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)							
CAB - Com/Add Ballot 2							
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							

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

PTS Change Control

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

Project	**2017-05**	**Home**
Project Name	Project 2017-05 NUC-001-3 Periodic Review	
Status	Working to Comment Posting	
Comments	The Standards Committee appointed team members July 2017. The kickoff meeting will be in September 12-13, 2017 NERC office in DC.	
Deliverable	Periodic Review of NUC-001-3 Standard	
Deadline	N/A	
Priority in RSDP, click to see applicable Footnote	Footnote 9, Low (was Medium previously)	
P81 Req (2013)	N/A	
Number of Directives	N/A	
No. of Guidances (see Note 2)	N/A	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Mat Bunch	
PMOS Liaison	Amy Casuscelli	
Affected Standards	NUC-001-3	
Last Updated	9/5/2017	

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR	5/10/2017	5/23/2017	5/10/2017	5/23/2017			
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1							
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)							
CAB - Com/Add Ballot 2							
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							

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

PTS Change Control

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

Project	**2017-06**	**Home**
Project Name	Project 2017-06 Modifications to BAL-002-2	
Status	Nominations	
Comments	The project is seeking additional nominations to supplement the drafting team through August 9, 2017. Anticipate team member appointments in October.	
Deliverable	BAL-002-3	
Deadline	N/A	
Priority in RSDP, click to see applicable Footnote	Footnote 8, Medium	
P81 Req (2013)	N/A	
Number of Directives	N/A	
No. of Guidances (see Note 2)	N/A	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Darrel Richardson	
PMOS Liaison	Ken Lanehome	
Affected Standards	BAL-002-2	
Last Updated	9/5/2017	

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR	6/20/2017	7/3/2017	6/20/2017	7/3/2017			
Nominations - DT	7/27/2017	8/9/2017	7/27/2017	8/9/2017			Supplemental Nominations
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	6/20/2017	7/20/2017	6/20/2017	7/20/2017			
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)							
CAB - Com/Add Ballot 2							
CAB - Com/Add Ballot 3							

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

PTS Change Control

Reason for Update	Date	Notes
Created Project in PTS	5/30/2017	Created Project record.
Assign PMOS Liaison	6/14/2017	Ken Lanehome accepted appointment as PMOS liaison.

Project	**2017-07**	**Home**
Project Name	Standards Alignment with Registration	
Status	SAR	
Comments	Nominations are being sought for Standard Authorization Request (SAR) drafting team members through 8 p.m. Eastern, Monday, August 14, 2017. A 30-day formal comment period on the SAR for Standards Alignment with Registration is open through 8 pm. Eastern, Wednesday, August 30, 2017. A 30-day formal comment period on the SAR for MOD-032-1 – Data for Power System Modeling and Analysis is open through 8 p.m. Eastern, Wednesday, August 30, 2017.	
Deliverable		
Deadline		
Priority in RSDP, click to see applicable Footnote	N/A	
P81 Req (2013)		
Number of Directives		
No. of Guidances (see Note 2)		
Directionally consistent with IERP findings (See Note 5)		
Developer	Laura Anderson	
PMOS Liaison	Mike Brytowski	
Affected Standards		
Last Updated	9/5/2017	

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR	8/1/2017	8/14/2017	8/1/2014	8/14/2014	(1096)		
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	8/1/2017	8/30/2017	8/1/2017	8/30/2017			
SP2 - SAR/PR/WP Posting 2							
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
Assign PMOS Liaison	7/27/2017	Mike Brytowski accepted appointment as PMOS liaison.

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

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

RSC Meeting #17-4, Agenda Item 4.0 Open Action Items

Item	Description	Owner	Due	Status
4.1	Michael Jones, Herb Schrayshuen and Quintin Lee volunteered to assist Gerry Dunbar on reviewing the draft A-01 Criteria document. Status Report by next RSC meeting.	Gerry Dunbar	8/23/17	Ongoing
4.2				

DRAFT

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Weekly Standards & Compliance Bulletin

October 2–8, 2017

ACTIVE STANDARDS POSTINGS

Current and Upcoming Ballots (ballot periods close at 8:00 p.m. Eastern)			
Project	**Action**	**Start Date**	**End Date**
Project 2015-10 – Single Points of Failure | TPL-001-5	Initial Ballot and Non-binding Poll	10/13/17	10/23/17
Project 2016-02 – Modifications to CIP Standards | CIP-002-6	Initial Ballot and Non-binding Poll	10/20/17	10/30/17
NEW Project 2015-09 – Establish and Communicate System Operating Limits | FAC-011-4, FAC-014-3, FAC-015-1, Implementation Plan, System Voltage Limit Definition	Initial Ballot and Non-binding Poll	11/03/17	11/13/17
Join Ballot Pools (ballot pool windows close at 8:00 p.m. Eastern)			
Project	**Action**	**Start Date**	**End Date**
Project 2015-10 – Single Points of Failure | TPL-001-5	Join Ballot Pools	09/08/17	10/06/17
Project 2016-02 – Modifications to CIP Standards | CIP-002-6	Join Ballot Pools	09/14/17	10/13/17
NEW Project 2015-09 – Establish and Communicate System Operating Limits | FAC-011-4, FAC-014-3, FAC-015-1, Implementation Plan, System Voltage Limit Definition	Join Ballot Pools	09/29/17	10/30/17
Project	**Action**	**Start Date**	**End Date**
Project 2015-10 – Single Points of Failure | TPL-001-5	Comment Period	09/08/17	10/23/17
Project 2016-02 – Modifications to CIP Standards | CIP-002-6	Comment Period	09/14/17	10/30/17
NEW Project 2015-09 – Establish and Communicate System Operating Limits | System Operating Limit (SOL) and SOL Exceedance Definitions	Comment Period	09/29/17	10/30/17

NEW Project 2015-09 – Establish and Communicate System Operating Limits | FAC-011-4, FAC-014-3, FAC-015-1, Implementation Plan, System Voltage Limit Definition	Comment Period	09/29/17	11/13/17

OTHER ACTIVE COMMENT PERIODS

Posted for Comment			
Posting	**Action**	**Start Date**	**End Date**
Comment Period Open for Second Drafts of the ERO Enterprise Long-Term Strategy, Operating Plan, and 2018 Metrics: The second drafts of the ERO Enterprise Long-Term Strategy, Operating Plan, and 2018 Metrics are now available on NERC's website. A cover letter providing a summary of the documents and next steps is also provided. The following draft documents are posted for review and/or comment (redline versions against the first drafts are also available): • ERO Enterprise Long-Term Strategy – Clean and Redline • ERO Enterprise Operating Plan – Clean and Redline • 2018 ERO Enterprise Metrics – Clean and Redline	Submit comments and questions to Erika Chanzes.	09/15/17	10/02/17
Comment Period Open for Regional Reliability Standard PRC-006-NPCC-2: A comment period for PRC-006-NPCC-2 – Automatic Underfrequency Load Shedding is open through October 16, 2017. This initial draft has been developed in accordance with the NPCC Regional Standard Process Manual and within the scope of NPCC Regional Standard Authorization Request, which was accepted by the	Submit comments electronically through the NPCC Website.	09/06/17	10/16/17

NPCC Regional Standard Committee. The revisions are also presented as mandated by the NERC Rules of Procedure. This initial draft does not include the Violation Severity Levels, which will be developed for the next posting period.			
Comment Period Open for Gas and Electrical Operational Coordination Considerations Draft Reliability Guideline: The NERC Operating Committee's Operating Reliability Subcommittee developed the draft Reliability Guideline: Gas and Electrical Operational Coordination Considerations. Coordination of operations between the gas and electric industries has become increasingly important over the course of the last decade. The electric power sector's use of gas has grown exponentially in many areas of North America due to increased availability of gas, potentially more competitive costs in relation to other fuels and a move throughout the industry to lower emissions to meet environmental goals. With increased growth in gas usage comes greater reliance and associated risk due to the dependency that each industry now has on the other. The operational impact of these dependencies requires gas and electric system operators to actively coordinate planning and operations. The goal of the coordination is to ensure that both the gas and electric systems remain secure and reliable during normal, abnormal and emergency conditions. This guideline attempts to provide a set of principles and strategies that may be adopted should the region in which you operate require close coordination due to increased dependency. This guideline also focuses on the areas of preparation, coordination, communication, and intelligence that may be applied in order to coordinate operations and minimize risk.	Submit comments via email.	09/20/17	11/03/17

The NERC Operating Committee reviewed the initial draft of the guideline at its September 2017 meeting and approved it for a 45-day industry comment period. A draft version of the Reliability Guideline has been posted on the NERC website for industry comment.			

STANDARDS NEWS

NEW Resources Posted

NERC has posted the streaming webinar and slide presentation for the September 20, 2017 Project 2015-10 – Single Points of Failure webinar.

QUICK LINKS

Register in the SBS
Projected Standards Posting Schedule
Project Tracking Spreadsheet
Standards Related Questions – Single Portal
2017–2019 Reliability Standards Development Plan

GENERAL COMPLIANCE AND ENFORCEMENT NEWS

NEW NERC Releases One New Reliability Standard Audit Worksheet

A new Reliability Standard Audit Worksheet (RSAW) for PRC-026-1 – Relay Performance During Stable Power Swings has been posted to the RSAW homepage under the "Current RSAWs for Use." PRC-026-1 becomes effective on January 1, 2018.

Newly Effective Standards

The following standards became effective on October 1, 2017:

- COM-001-3 – Communications
- IRO-002-5 – Reliability Coordination – Monitoring and Analysis
- PRC-006-3 – Automatic Underfrequency Load Shedding

QUICK LINKS

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

STANDARDS SUBJECT TO FUTURE ENFORCEMENT

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

U.S. Effective Date	Standard(s)
October 1, 2017 NOW EFFECTIVE	COM-001-3 – Communications
	IRO-002-5 – Reliability Coordination – Monitoring and Analysis
	PRC-006-3 – Automatic Underfrequency Load Shedding
January 1, 2018	BAL-002-2 – Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event
	PRC-026-1 – Relay Performance During Stable Power Swings (Requirement 1);
April 1, 2018	IRO-018-1(i) – Reliability Coordinator Real-time Reliability Monitoring and Analysis Capabilities
	TOP-010-1(i) – Real-time Reliability Monitoring and Analysis Capabilities
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 2, 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 2, 2.1–2.1.5);
	TOP-001-4 – Transmission Operations
	TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events (Requirement 2)
September 1, 2018	CIP-003-6 – Cyber Security – Security Management Controls (Requirement 2, Att. 1, Sec. 2 and 3);
January 1, 2019	TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events (Requirement 5)
January 1, 2020	PRC-026-1 – Relay Performance During Stable Power Swings (Requirements 2–4)
July 1, 2020	PRC-002-2 – Disturbance Monitoring and Reporting Requirements (50% compliance for Requirements 2–4, 6–11)
January 1, 2021	TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events (Requirements 6, 6.1–6.4)

January 1, 2022	TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events (Requirements 3,4,7)
July 1, 2022	PRC-002-2 – Disturbance Monitoring and Reporting Requirements (100% compliance for Requirements 2–4, 6–11)
	VAR-501-WECC-3 – Power System Stabilizer (Requirement 3 has an effective date of July 1, 2022 for units placed in service prior to final regulatory approval.)

BOARD OF TRUSTEES AND FERC ACTION

NEW FERC Issuances

On September 26, 2017, FERC issued a delegated order approving an errata to Reliability Standards VAR-001-4.1 – Voltage and Reactive Control, VAR-002-4 – Generator Operation for Maintaining Network Schedule and regional Reliability Standard VAR-501-WECC-3 – Power System Stabilizer.

FERC's 2017 issuances are available here.

NEW NERC Filings

On September 26, 2017, NERC submitted to FERC a petition for approval of proposed Reliability Standards CIP-013-1, CIP-005-6, and CIP-010-3 addressing Supply Chain Cybersecurity Risk Management.

On September 28, 2017, NERC filed with FERC the 2017 Annual Report on Wide-Area Analysis of Technical Feasibility Exceptions (TFEs).

NERC's 2017 filings to FERC are available here.

UPCOMING EVENTS

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

Workshops and Conferences

- Fifth Annual Monitoring and Situational Awareness Technical Conference – October 3–4, 2017, Atlanta | Register | Hotel and Travel Information | Presentations from Previous Conferences

- GridSecCon – October 17–20, 2017, St. Paul, MN | Conference Details | **Registration Information Coming Soon**

Webinars

There are no webinars currently scheduled.

Standing Committee Meetings and Conference Calls

- Standards Committee Conference Call – 1:00–4:00 p.m. Eastern, October 18, 2017 | Register

Standard Drafting Team Meetings and Conference Calls

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

- **NEW** Project 2016-02 – Modifications to CIP Standards Conference Call – 11:00 a.m.–1:00 p.m. Eastern, October 6, 2017 | Register
- **NEW** Project 2016-02 – Modifications to CIP Standards Conference Call – 11:00 a.m.–1:00 p.m. Eastern, October 13, 2017 | Register
- Project 2017-04 – Periodic Review of Interchange Scheduling and Coordination Standards Team Meeting – October 17–18, 2017, Dallas, TX | Register
- **NEW** Project 2016-02 – Modifications to CIP Standards Conference Call – 11:00 a.m.–1:00 p.m. Eastern, October 20, 2017 | Register
- **NEW** Project 2016-02 – Modifications to CIP Standards Conference Call – 11:00 a.m.–1:00 p.m. Eastern, October 27, 2017 | Register
- **NEW** Project 2016-02 – Modifications to CIP Standards Conference Call – 11:00 a.m.–1:00 p.m. Eastern, November 3, 2017 | Register
- Project 2017-05 – NUC-001-3 Periodic Review Team Conference Call – 1:00–3:00 p.m. Eastern, October 17, 2017 | 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 register through our ERO portal. For more information about any of the compliance news listed in the bulletin, please contact Tiffany Whaley.

NERC's Compliance Guidance

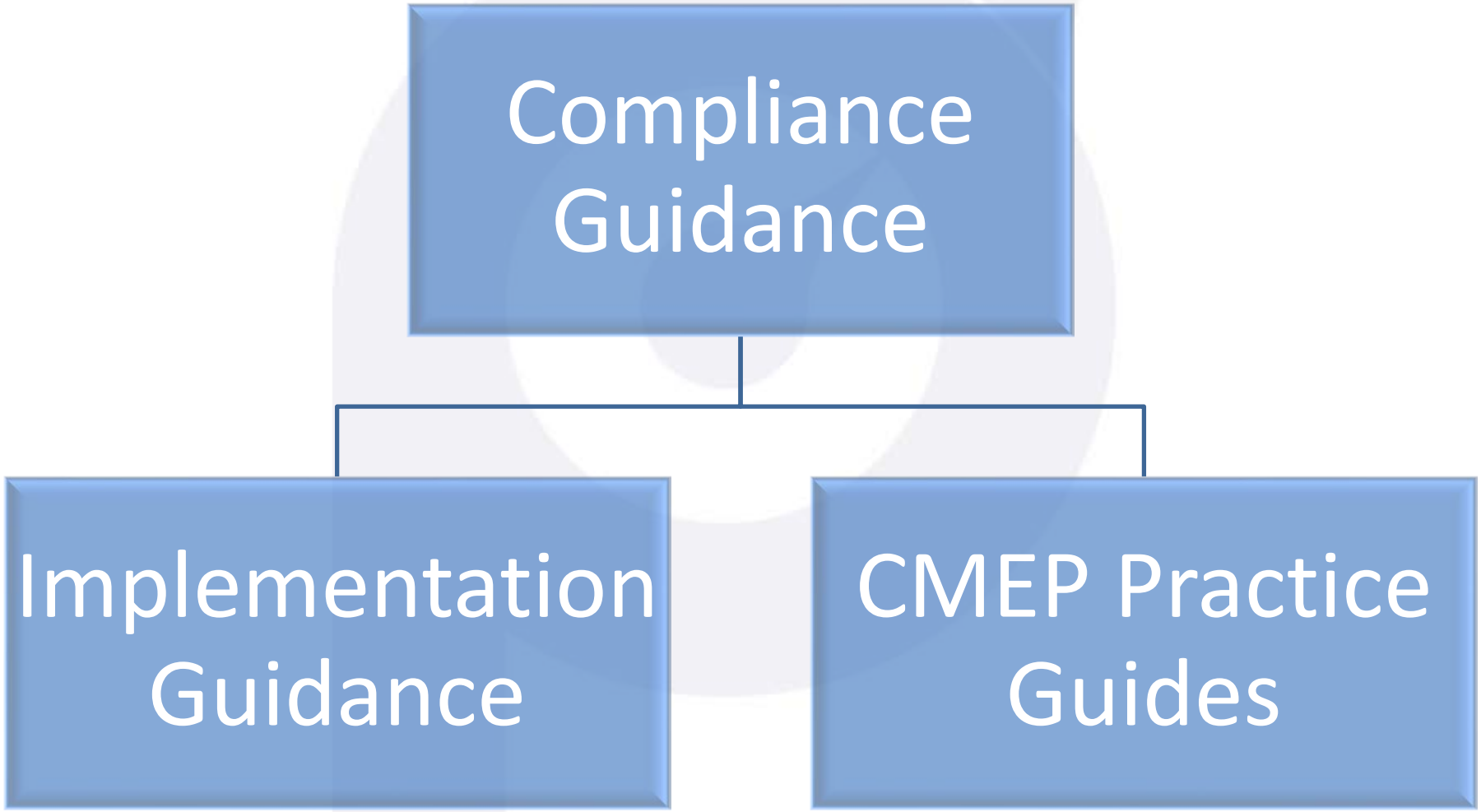
Guy V. Zito
NPCC RSC
October 11-12, 2017

- Compliance Guidance Policy
- Types of Compliance Guidance
- Prequalified Organizations
- Endorsement process
- Implementation guidance development aid
- Key Takeaways
- Questions and answers

- Purpose of policy
  - Industry implement Reliability Standards
  - ERO CMEP staff execute duties
- Compliance Guidance team
  - Reviewed role, purpose, development, use, and maintenance
  - Recommended use of examples
- NERC Board or Trustees approved Compliance Guidance Policy

Principles:

- Cannot change scope of Reliability Standard
- May be developed concurrently with Reliability Standard,
- Should not conflict
- Should be developed collaboratively
- Not only way to comply
- Additional Considerations:
  - Finite and limited set
  - Related guidance in one location
  - Consider revising standard
  - Apply professional judgment
  - Feedback loops


Compliance Guidance
Implementation Guidance
CMEP Practice Guides

Implementation Guidance:

- Developed by industry, for industry
- Examples or approaches to comply
  - One of several possible approaches
- Developed by:
  - Standard Drafting Team (SDT)
    - Vetted by industry in a comment period
    - Endorsed by ERO Enterprise
  - Pre-Qualified Organization
    - Endorsed by ERO Enterprise

CMEP Practice Guides:

- Developed *by ERO Enterprise*, *for ERO Enterprise*
  - May be initiated through industry discussions
  - Publically posted
- ERO Enterprise CMEP staff approach
  - Fosters consistency
- May not be Reliability Standard specific
- All Guidance reviewed by NERC Vice President, Deputy General Counsel, and Director of Enforcement

Pre-Qualified Organizations

Approved by NERC Compliance and Certification Committee (CCC)

- The organization must:
  - Be actively involved in NERC operations
  - Have methods to assure technical rigor
  - Possess ability to vet content

Pre-Qualified Organizations

1. American Public Power Association (APPA)
2. Canadian Electricity Association (CEA)
3. Edison Electric Institute (EEI)
4. Electricity Consumers Resource Council (ELCON)
5. Electric Power Supply Association (EPSA)
6. ISO/RTO Council
7. Large Public Power Council (LPPC)
8. National Association of Regulatory Utility Commissioners (NARUC)
9. National Rural Electric Cooperative Association (NRECA)
10. North American Generator Forum (NAGF)
11. North American Transmission Forum (NATF)
12. Northwest Public Power Association (NWPPA)
13. Nuclear Energy Institute (NEI)
14. Transmission Access Policy Study Group (TAPS)
15. Western Interconnection Compliance Forum (WICF)
16. NERC Planning Committee (PC)
17. NERC Operating Committee (OC)
18. NERC Critical Infrastructure Protection Committee (CIPC)
19. Regional Entity Stakeholder Committees

Pre-Qualified Organizations

- Regional Entity Stakeholder Committees
  - NPCC Compliance Committee (CC) Process for Submitting Implementation Guidance to NERC
  - Any NPCC Registered Entity, Committee or Staff
  - Joint CC and RSC Review for comments(30 days)
  - CC Reviews Comments
  - CC Votes on Implementation Guidance
  - CC Submits Implementation Guidance to NERC

- Standard Drafting Team (SDT)
  - Identifies examples
  - Reviews existing guidance
- Examples vetted by industry
- Decision to submit made by
  - Project Management and Oversight Subcommittee (PMOS) liaison
  - NERC Standards Developer submit for ERO Enterprise endorsement
- May not submit guidance after standard is approved
  - Must be submitted by Pre-Qualified Organization

Endorsement of Implementation Guidance:

- Pre-Qualified Organization or SDT submit proposed guidance
  - Email to ComplianceGuidance@nerc.net
  - Include Implementation Guidance Submittal Form
- NERC
  - Acknowledges receipt
  - Posts proposed guidance
  - Distributes to ERO SME
- ERO endorses or declines to endorse
- Publicly posted
  - Non-Endorsed noted in spreadsheet

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Guidance Development Aid

August 3, 2017

Implementation Guidance Development Reference Sheet		
1.	Ensure guidance does not conflict with the Purpose of the Reliability Standard.	
2.	Ensure guidance does not conflict with the meaning, or intent, of the Requirement and Measure.	
3.	Ensure guidance is not a whitepaper, position paper, concept paper, or technical reference type document that does not provide specific examples or approaches to compliance.	
4.	Ensure guidance is not region specific, such as guidance for a Regional Reliability Standard.	
5.	Ensure guidance is not a Frequently Asked Questions (FAQ) type document.	
6.	Ensure guidance provides specific examples or approaches to compliance.	
7.	Consider if an entity followed the approach or example, would it generally lead the entity to compliance.	
8.	Consider using illustrations such as diagrams, sample records, flowcharts, templates, etc.	
9.	Ensure guidance does not conflict with, or contradict, previously approved documents such as FERC Orders, FERC Interpretations, Reliability Standard Implementation Plans, Reliability Standard Guidelines and Technical Basis, RSAWs, NERC Guidance, NERC Glossary of Terms, Endorsed Compliance Guidance, Compliance Bulletins and Directives, etc.	
10.	Ensure guidance capitalizes terms defined in the NERC Glossary of Terms when the term is intended to have the same meaning as defined in the Glossary.	
11.	Consider spelling out, or defining, acronyms during their initial use.	
12.	Ensure guidance does not add compliance obligations to an entity that is not specifically required by the subject Reliability Standard and Requirement.	
13.	Ensure guidance does not make the subject Reliability Standard and Requirement less restrictive.	
14.	Consider using softer words such as "should consider", "may want to", "recommended", etc. when the processes, procedures, or approaches described are examples and are not prescriptive and mandatory.	
15.	Ensure guidance does not include language that attempts to describe an audit approach.	
16.	Ensure guidance correctly references footnotes, citations, active links, illustrations, table numbers, attachments, addendums, appendices, etc.	

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

17.	Ensure guidance that references external sources are referencing the latest version of the external source.	
18.	Consider using guidance language that is clear, concise, and complete.	
19.	Ensure guidance does not skip steps or stop short of complying with the subject Reliability Standard and Requirement by addressing the entire Requirement in sufficient detail.	
20.	Consider using the specific language of the subject Reliability Standard and Requirement when possible.	
21.	Ensure guidance does not introduce new terminology, attempt to define a term, interpret a term, or clarify an ambiguity in the subject Reliability Standard and Requirement.	
22.	Consider avoiding terms that were used in previous versions of a Reliability Standard, but are no longer in use in the current version of the subject Reliability Standard and Requirement.	
23.	Consider the value of developing guidance that addresses Reliability Standards and Requirements that are subject to future retirement.	
24.	Ensure Standard Drafting Teams (SDT) write compliance expectations into the Requirements of the Reliability Standard, and not in the guidance (Applies to SDT only).	

- Implementation Guidance may be an approach
  - Developed by industry
  - Endorsed by the ERO Enterprise
- CMEP Practices Guides
  - Developed by ERO Enterprise
  - Not standard-specific
- During development of guidance reference the Implementation Guidance Development Aid
- Review the Compliance Guidance Policy document for more details
- Check Compliance Guidance webpage regularly for updates

Questions ??

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Compliance Guidance

Ken McIntyre, Vice President and Director of Standards and Compliance
NERC Planning Committee Meeting
September 12-13, 2017

RELIABILITY | ACCOUNTABILITY

Overview

- Compliance Guidance Policy
- Types of Compliance Guidance
- Prequalified Organizations
- Endorsement process
- Implementation guidance development aid
- Key Takeaways
- Questions and answers

Compliance Guidance Policy

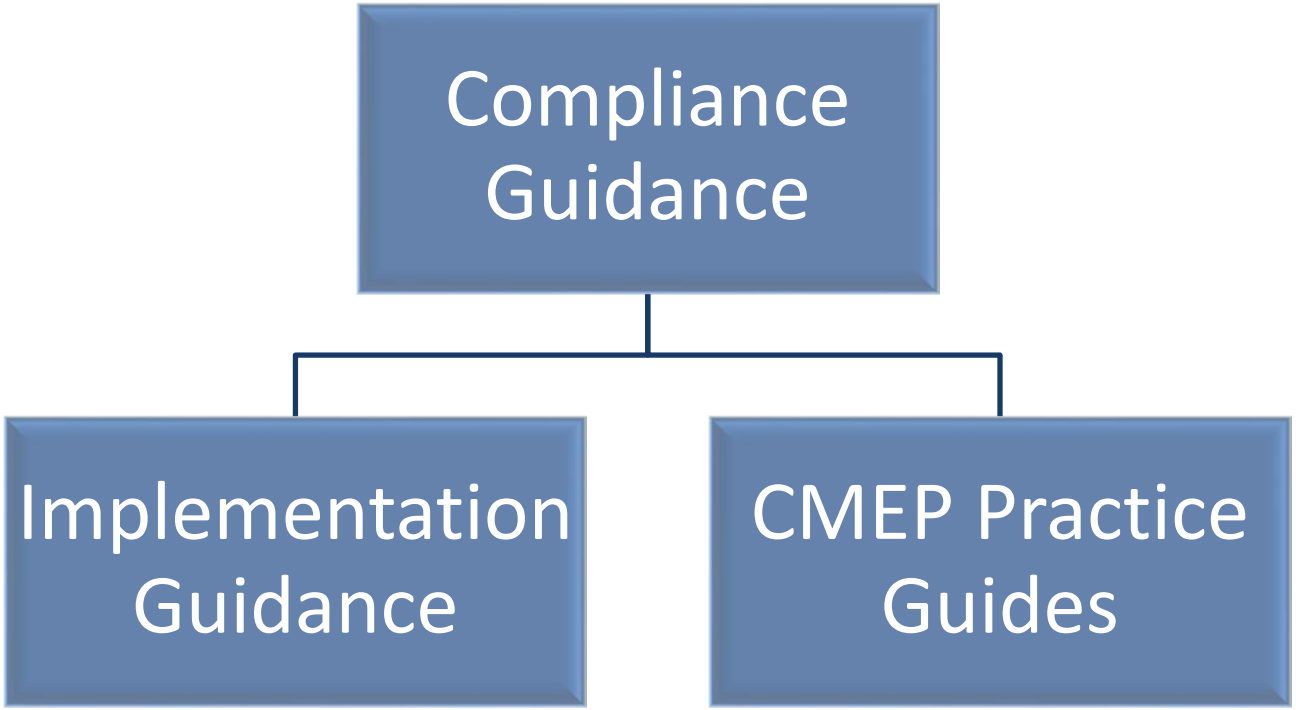
- Purpose of policy
  - Industry implement Reliability Standards
  - ERO CMEP staff execute duties
- Compliance Guidance team
  - Reviewed role, purpose, development, use, and maintenance
  - Recommended use of examples
- NERC Board or Trustees approved Compliance Guidance Policy

Compliance Guidance Policy

Principles:

- Cannot change scope of Reliability Standard
- May be developed concurrently with Reliability Standard,
- Should not conflict
- Should be developed collaboratively
- Not only way to comply
- Additional Considerations:
  - Finite and limited set
  - Related guidance in one location
  - Consider revising standard
  - Apply professional judgment
  - Feedback loops

Types of Guidance



Types of Guidance

Implementation Guidance:

- Developed by industry, for industry
- Examples or approaches
  - One of several possible approaches
- Developed by:
  - Standard Drafting Team (SDT)
    - Vetted by industry
  - Pre-Qualified Organization
    - Endorsed by ERO Enterprise

Types of Guidance

CMEP Practice Guides:

- Developed *by ERO Enterprise*, *for ERO Enterprise*
  - May be initiated through industry discussions
  - Publically posted
- ERO Enterprise CMEP staff approach
  - Fosters consistency
- May not be Reliability Standard specific
- All Guidance reviewed by NERC Vice President, Deputy General Counsel, and Director of Enforcement

Pre-Qualified Organizations

Approved by Compliance and Certification Committee (CCC)

- The organization must:
  - Be actively involved in NERC operations
  - Have methods to assure technical rigor
  - Possess ability to vet content

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Pre-Qualified Organizations

1. American Public Power Association (APPA)
2. Canadian Electricity Association (CEA)
3. Edison Electric Institute (EEI)
4. Electricity Consumers Resource Council (ELCON)
5. Electric Power Supply Association (EPSA)
6. ISO/RTO Council
7. Large Public Power Council (LPPC)
8. National Association of Regulatory Utility Commissioners (NARUC)
9. National Rural Electric Cooperative Association (NRECA)
10. North American Generator Forum (NAGF)
11. North American Transmission Forum (NATF)
12. Northwest Public Power Association (NWPPA)
13. Nuclear Energy Institute (NEI)
14. Transmission Access Policy Study Group (TAPS)
15. Western Interconnection Compliance Forum (WICF)
16. NERC Planning Committee (PC)
17. NERC Operating Committee (OC)
18. NERC Critical Infrastructure Protection Committee (CIPC)
19. Regional Entity Stakeholder Committees

Pre-Qualified Organizations

- Standard Drafting Team (SDT)
  - Identifies examples
  - Reviews existing guidance
- Examples vetted by industry
- Decision to submit made by
  - Project Management and Oversight Subcommittee (PMOS) liaison
  - NERC Standards Developer submit for ERO Enterprise endorsement
- May not submit guidance after standard is approved
  - Must be submitted by Pre-Qualified Organization

Endorsement Process

Endorsement of Implementation Guidance:

- Pre-Qualified Organization or SDT submit proposed guidance
  - Email to ComplianceGuidance@nerc.net
  - Include Implementation Guidance Submittal Form
- NERC
  - Acknowledges receipt
  - Posts proposed guidance
  - Distributes to ERO SME
- ERO endorses or declines to endorse
- Publicly posted
  - Non-Endorsed noted in spreadsheet

Implementation Guidance Development Aid

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Guidance Development Aid

August 3, 2017

Implementation Guidance Development Reference Sheet		
1.	Ensure guidance does not conflict with the Purpose of the Reliability Standard.	
2.	Ensure guidance does not conflict with the meaning, or intent, of the Requirement and Measure.	
3.	Ensure guidance is not a whitepaper, position paper, concept paper, or technical reference type document that does not provide specific examples or approaches to compliance.	
4.	Ensure guidance is not region specific, such as guidance for a Regional Reliability Standard.	
5.	Ensure guidance is not a Frequently Asked Questions (FAQ) type document.	
6.	Ensure guidance provides specific examples or approaches to compliance.	
7.	Consider if an entity followed the approach or example, would it generally lead the entity to compliance.	
8.	Consider using illustrations such as diagrams, sample records, flowcharts, templates, etc.	
9.	Ensure guidance does not conflict with, or contradict, previously approved documents such as FERC Orders, FERC Interpretations, Reliability Standard Implementation Plans, Reliability Standard Guidelines and Technical Basis, RSAWs, NERC Guidance, NERC Glossary of Terms, Endorsed Compliance Guidance, Compliance Bulletins and Directives, etc.	
10.	Ensure guidance capitalizes terms defined in the NERC Glossary of Terms when the term is intended to have the same meaning as defined in the Glossary.	
11.	Consider spelling out, or defining, acronyms during their initial use.	
12.	Ensure guidance does not add compliance obligations to an entity that is not specifically required by the subject Reliability Standard and Requirement.	
13.	Ensure guidance does not make the subject Reliability Standard and Requirement less restrictive.	
14.	Consider using softer words such as "should consider", "may want to", "recommended", etc. when the processes, procedures, or approaches described are examples and are not prescriptive and mandatory.	
15.	Ensure guidance does not include language that attempts to describe an audit approach.	
16.	Ensure guidance correctly references footnotes, citations, active links, illustrations, table numbers, attachments, addendums, appendices, etc.	

RELIABILITY | ACCOUNTABILITY

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

17.	Ensure guidance that references external sources are referencing the latest version of the external source.	
18.	Consider using guidance language that is clear, concise, and complete.	
19.	Ensure guidance does not skip steps or stop short of complying with the subject Reliability Standard and Requirement by addressing the entire Requirement in sufficient detail.	
20.	Consider using the specific language of the subject Reliability Standard and Requirement when possible.	
21.	Ensure guidance does not introduce new terminology, attempt to define a term, interpret a term, or clarify an ambiguity in the subject Reliability Standard and Requirement.	
22.	Consider avoiding terms that were used in previous versions of a Reliability Standard, but are no longer in use in the current version of the subject Reliability Standard and Requirement.	
23.	Consider the value of developing guidance that addresses Reliability Standards and Requirements that are subject to future retirement.	
24.	Ensure Standard Drafting Teams (SDT) write compliance expectations into the Requirements of the Reliability Standard, and not in the guidance (Applies to SDT only).	

Key Takeaways

- Implementation Guidance may be an approach
  - Developed by industry
  - Endorsed by the ERO Enterprise
- CMEP Practices Guides
  - Developed by ERO Enterprise
  - Not standard-specific
- During development of guidance reference the Implementation Guidance Development Aid
- Review the Compliance Guidance Policy document for more details
- Check Compliance Guidance webpage regularly for updates

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Questions and Answers

Remedial Action Schemes (RAS)
NERC PRC-012-2
FERC Order 837
Docket RM-16-20-000
Issued September 20, 2017

Guy V. Zito
NPCC RSC
October 11-12, 2017

FERC Order 837

- **Background**
- **PRC-012-2 Remedial Action Schemes (RAS)**
- **Implementation**
- **RAS Potential Strategies**
- **Future Actions**

FERC Order 837

Background

- NPCC Type I, II, III Special Protection Systems (SPS)- NERC RAS
- NERC SCPS- RAS, Local Area Protection schemes (WECC LAPs), SPSs. Inconsistencies
- PRC-012-0- RAS/SPS, PRC-013-0 Database, PRC-014-0 Assessment “fill-in-the blank” **not** FERC approved, PRC-015-0 Data and PRC-016-0 Misops, PRC-017-0 M & T, **approved** then refiled as Version 1 standards with RAS nomenclature
- RAS Definition Approved and Effective April 1, 2017

FERC Order 837

Background cont.

What is a Remedial Action Scheme - RAS?

A scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation (MW and Mvar), tripping load, or reconfiguring a System(s). RAS accomplish objectives such as:

- *Meet requirements identified in the NERC Reliability Standards;*
- *Maintain Bulk Electric System (BES) stability;*
- *Maintain acceptable BES voltages;*
- *Maintain acceptable BES power flows;*
- *Limit the impact of Cascading or extreme events.*

FERC Order 837

Background cont.

What is an NPCC Special Protection System SPS?

A protection system designed to detect abnormal system conditions and take corrective action other than the isolation of faulted elements. Such action may include changes in load, generation, or system configuration to maintain system stability, acceptable voltages or power flows. (Functions of NPCC SPSs GR, LR, TCT and Other)

However, the following are not considered SPS's:

-Automatic UFLS; -Automatic UVLS, and -Manual or automatic locally controlled shunt devices.

FERC Order 837

Background, continued

- NPCC SPS Database, RCC approval annually
- NPCC Directory 7 approval process for SPS
- PRC-012-2 filed August 5, 2016
  - Supersede PRC-012-1, PRC-013-1, and PRC-014-1
  - Retire PRC-015-1, PRC-016-1
- PRC-017-1 RAS Maintenance and Testing will be retired in accordance with the PRC-005-6 Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance March 31, 2027
- RAS NOPR industry comments were due April 10, 2017
- RAS Order 837 issued September 20, 2017

FERC Order 837

- **PRC-012-2**
  - Applicable to RC, PC, RAS Entity (TO, GO, DP – owner of RAS)
  - 9 requirements (paraphrased)
    - RAS Entity provides all information to RC
    - RC performs RAS review
    - RAS Entity will resolve all RC issues
    - PC evaluations every 5 years
    - RAS Entity evaluates operations and misops.
    - RAS Entity participate to develop CAP to RC in 6 months
    - RAS Entity implement CAP- revise and notify RC
    - RAS Entity functional test every 6/12
    - RC update database every 12 months- at a minimum

FERC Order 837

PRC-012-2 Implementation

- FERC Final Order Date (Sept. 20, 2017)
- US-Effective Date of FERC Final Rule: 60 days after publication in the Federal Register-which appeared in the September 27, 2017 so "Effective Date" (in the context of FERC) is November 27, 2017.
- Canada-Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is thirty six (36) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.
- Enforcement/effective date of the Standard- "the first day of the first calendar quarter that is 36 months after Commission Approval Date" -January 1, 2021

FERC Order 837

- **PRC-012-2 Implementation – cont.**
  - Clock starts on Implementation Plan or adhere to target dates in the Plan.
  - Limited Impact-A RAS implemented prior to the effective date of PRC-012-2 that has been through the regional review processes of WECC or NPCC and is classified as either a Local Area Protection Scheme (LAPS) in WECC or **a Type III in NPCC is recognized as a limited impact RAS upon the effective date of PRC-012-2 and is subject to all applicable requirements.**

FERC Order 837

- **PRC-012-2 Implementation – cont.**
  - R4 (PC Evaluation of RAS) completed within 5 full calendar years following the effective date.
  - RAS (Functional Test)not designated as limited impact, initial performance of obligations under Requirement R8 must be completed at least once within six (6) full calendar years after the effective date.
  - RAS designated as “limited impact”, initial performance of obligations under Requirement R8 must be completed at least once within twelve (12) full calendar years after the effective date
  - Requirement R9 (RC Database) within twelve full calendar months after the effective date

FERC Order 837

- **PRC-012-2**
  - NPCC participated in standard development
  - Promoted the concept of “limited impact”, cost effectiveness and security vs. reliability
  - Recognition and allowance RC to use Regional processes(SPS/RAS) to conduct and facilitate their review of RASs prior to commissioning
  - Alignment of SPS Type 1 and 2 with RAS and Type 3 with “limited impact” to reduce disruption of mechanisms
  - Database requirements for RCs may be met through regional databases

FERC Order 837

NOPR Solicitations for Comments

- PRC-012-2 will not modify or supersede performance requirements in TPL-001-4
  - Table 1 non-consequential load loss may not exceed 75 MW for certain Category P1, P2, or P3 contingencies (ensure Directory 7 revision conforms)
- PRC-012-2 processes
  - LAPS or Type III RAS will be compliant with Reliability Standard TPL-001-4 prior to the effective date of Reliability Standard PRC-012-2 w.r.t. the 75 MW loss of load for LR RAS

FERC Order 837

NOPR Solicitations for Comments, continued

- Should “limited impact RAS” be a NERC defined term and added to the NERC Glossary of Terms?

FERC Order 837 RAS

RAS, Potential NPCC Strategy

- Remove/identify all non-conforming RAS from SPS list-used for compliance
- Have NPCC TF(s) review these SPS removals from RAS list for potential reliability gaps
- Identify any reliability gaps and propose solutions to address the gaps.
  - Non-RAS being removed, still subject to PRC-005-6 "Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance"
  - End to end testing requirement
  - SPS Controller

FERC Order 837 RAS

RAS, Potential NPCC Strategy

- Identify newly conforming SPS that are RAS and to be added to the list
- Notify owners of those RAS being added to the list
- TF to ensure RAS listing has all the attributes of Attachment 3
- TF to discuss potential process to formally approve existing newly identified RAS that weren't on the SPS list
- TF to conduct approval process for those newly identified RAS

FERC Order 837 RAS

RAS, Potential NPCC Strategy

- Finalize the RAS list and approval with RCC (for compliance use)
- Revise NPCC Glossary term for SPS to indicate "see NERC RAS"
- Begin development of revisions to NPCC documents related to RAS (Directory 1, 2, 7, RAS (SPS) List) to conform with PRC-012-2.
- Develop any new NPCC documents required to facilitate compliance with PRC-012-2 (e.g. for review, approval, testing and maintenance of RAS).

FERC Order 837 RAS

- **Future Actions**
  - RSC to continue to discuss, decide on suggested strategy and oversee the transition
  - Oversee implementation of conforming changes to Directories
- **Questions/Comments**

Area	Existing Type I, II, III SPS	Existing Type I, II, III SPS – Conforms to RAS Definition	Existing Type I, II, III SPS – Does Not Conform to RAS Definition	Protection System Not On the Current SPS List – Conforms to RAS Definition	Comments
HQTE	21	20	1 (Type III) *[SPS #138]*	0	
IESO	40	31	9 (All Type III) *[SPS #52, 190, 208, 209, 211, 212, 213, 217, 218]*	0	2 Pending review
ISO-NE	24	21	3 (1 Type I & 2 Type III) [*SPS #*109 Type I and SPS #31, 131 Type III)	2	1 Pending review
NBPC	9	9	0	0	
NS	13	12	1 (Type III) *[SPS #196]*	0	
NYISO	8	7	1 (Type III) *[SPS #35]*	5	
Total:	**115**	**100**	**15**	**7**	

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

September 15, 2017

VIA ELECTRONIC FILING

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C. 20426

RE: Errata to Implementation Plan for the Revised Definition of "Remedial Action Scheme Docket No. RM15-13-___

Dear Ms. Bose:

The North American Electric Reliability Corporation ("NERC") hereby requests approval of errata to the Implementation Plan for the Revised Definition of "Remedial Action Scheme" (the "RAS Implementation Plan") approved in Order No. 818 in the above-captioned docket.[1] As explained below, the errata is necessary to incorporate into the RAS Implementation Plan certain necessary implementation provisions from the Implementation Plan associated with Reliability Standard PRC-023-3 (the "PRC-023-3 Implementation Plan") that were inadvertently omitted from the RAS Implementation Plan.

On February 3, 2015, the North American Electric Reliability Corporation ("NERC") filed a petition for approval of proposed revisions to the definition of the term "Remedial Action Scheme" ("RAS") in the *Glossary of Terms Used in NERC Reliability Standards* ("NERC Glossary") and modifications to specified Reliability Standards to incorporate the revised RAS definition in place of the term Special Protection System.[2] Among others, the PRC-023 Reliability Standard was modified to incorporate the RAS definition, moving from version PRC-023-3 to PRC-023-4. There were no other substantive changes made to the Reliability Standard at that time. The Federal Energy Regulatory Commission ("Commission") approved the revised RAS definition and modifications to the Reliability Standards in Order No. 818 on November 19, 2015.

---

[1] Order No. 818, *Revisions to Emergency Operations Reliability Standards; Revisions to Undervoltage Load Shedding Reliability Standards; Revisions to the Definition of "Remedial Action Scheme" and Related Reliability Standards*, Docket Nos. RM15-7-000 et. al., (2015).

[2] *Petition of the North American Electric Reliability Corporation for Approval of Revisions to the Definition of "Remedial Action Scheme" and Proposed Reliability Standards*, Docket No. RM15-13-000 (Feb. 3, 2015).

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

When Reliability Standard PRC-023-3 was developed, the PRC-023-3 Implementation Plan included specific provisions for load-responsive phase protection systems on circuits identified by the Planning Coordinator pursuant to Requirement R6. Specifically, the provision allows each Transmission Owner, Generator Owner, and Distribution Provider to become compliant with in Requirements R1, R2, and R3 for those systems the latter of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date.

Additionally, the PRC-023-3 Implementation Plan included provisions regarding the retirement of Requirement R1, Criterion 6, contained in PRC-023-2. Specifically, the PRC-023-3 Implementation Plan specified that Requirement R1, Criterion 6 remains in effect through the implementation of Reliability Standard PRC-025-1 as specified in the Implementation Plan associated with PRC-025-1.

Recently, NERC noticed that in developing the RAS Implementation Plan, the provisions from the PRC-023-3 discussed above were inadvertently omitted. Those provisions must be carried forward for the PRC-023-4 version of the Reliability Standard to ensure that (1) entities continue to have the appropriate implementation period for complying with requirements applicable to load-responsive phase protection systems on circuits identified by the Planning Coordinator pursuant to Requirement R6, and (2) Requirement R1, Criterion 6 from PRC-023-2 remains in effect for the appropriate time. As such, NERC revised the RAS Implementation Plan to incorporate by reference the provisions from the PRC-023-3 Implementation Plan. The proposed modifications are identified in the redline version of the revised RAS Implementation Plan, provided as **Exhibit A** hereto. The proposed clean version of the revised RAS Implementation Plan is provided in **Exhibit B**.

For the reasons set forth above, NERC respectfully requests that the Commission approve the proposed errata to the RAS Implementation Plan.

Respectfully submitted,

/s/ Shamai Elstein

Shamai Elstein
Senior Counsel
North American Electric Reliability Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 400-3000
shamai.elstein@nerc.net

Counsel for the North American Electric Reliability Corporation

CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 15th day of September, 2017.

/s/ Shamai Elstein

Shamai Elstein

Counsel for the North American Electric Reliability Corporation

Exhibit A

Implementation Plan for the Revised Definition of “Remedial Action Scheme”

Redline Version

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan for the Revised Definition of "Remedial Action Scheme"

Project 2010-05.2 – Special Protection Systems

Background

The existing Glossary of Terms Used in NERC Reliability Standards definition for "Special Protection System" ("SPS") or "Remedial Action Scheme" ("RAS") lacks the specificity necessary to consistently identify what equipment or protection schemes qualify as SPS/RAS across the eight NERC Regions. The existing definition also does not clearly stipulate the characteristics of a SPS/RAS. The actions listed in the definition of SPS, which are incorporated by cross reference (NERC Glossary of Terms) into the definition of RAS, are ambiguous and may unintentionally include equipment whose purpose is not expressly related to preserving System reliability in response to predetermined System conditions. Employing a single term, i.e., RAS, and clarifying its definition will lead to more consistent application of the NERC Reliability Standards related to RAS.

The proposed definition of RAS must be broad to include the variety of System conditions monitored and corrective actions taken by RAS. Because of the diversity of RAS in both action and objective, the practical approach to the definition is to begin with a wide scope and then list specific exclusions. Without the exclusions, equipment and schemes that should not be considered RAS could be subject to the requirements of the RAS-related NERC Reliability Standards. The exclusion list assures that commonly applied protection and control systems are not unintentionally included as RAS.

The Project 2010-05.2 SPS SDT coordinated the development of the RAS definition with the development of PRC-010-1 by the SDT for Project 2008-02 – Undervoltage Load Shedding. The UVLS SDT introduced a new term, UVLS Program, into the Glossary of Terms Used in NERC Reliability Standards to clearly establish applicability of PRC-010-1. The proposed term UVLS Program is defined as: "An automatic load shedding program consisting of distributed relays and controls used to mitigate undervoltage conditions leading to voltage instability, voltage collapse, or Cascading impacting the Bulk Electric System (BES). Centrally controlled undervoltage-based load shedding is not included."

Note that the proposed definition excludes centrally controlled undervoltage-based load shedding. The UVLS SDT maintains that the design and characteristics of centrally controlled undervoltage-based load shedding are commensurate with RAS (wherein load shedding is the remedial action) and, as such, should be subject to RAS-related Reliability Standards. The Project 2010-05.2 SPS SDT agreed with this assessment and revised the definition of RAS to clarify that it is exclusive of distributed UVLS relays including the newly defined term UVLS Program. Therefore, the definition is inclusive of centrally controlled undervoltage-based load shedding. Collectively, the two definitions will promote consistency in the identification of centrally controlled undervoltage-based load shedding as RAS. The coordination of these revisions is required to maintain coverage of those systems and prevent a reliability gap. As a

result of these revisions, all NERC Reliability Standards that include the term RAS will be applicable to centrally controlled undervoltage-based load shedding upon the effective dates of the revised definitions of RAS and UVLS Program.

Requested Approvals

The definition of "**Remedial Action Scheme**" and the standards are listed below:

The following standards are proposed for approval to align the use of the single defined term RAS. This list is intended to reflect Reliability Standards currently in effect at the time of Project development. In certain cases, a standard listed below for approval may already be retired pursuant to an implementation plan of a successor version by the time the definition of "Remedial Action Scheme" becomes effective in a particular jurisdiction. In these cases, the standard below will not become effective.

CIP-002-3(i)	PRC-004-WECC-2	PRC-020-2
CIP-002-3(i)b	PRC-005-2(ii)	PRC-021-2
EOP-004-3	PRC-005-3(ii)	PRC-023-2(i)
FAC-010-3	PRC-006-1(i)	PRC-023-4[1]
FAC-011-3	PRC-012-1	TOP-005-3a
IRO-005-3.1(i)a	PRC-013-1	TPL-001-0.1(i)
MOD-029-2a	PRC-014-1	TPL-002-0(i)b
MOD-030-3	PRC-015-1	TPL-003-0(i)b
NUC-001-2.1(i)	PRC-016-1	TPL-004-0(i)a
PRC-001-1.1(i)	PRC-017-1	

Requested Retirements

CIP-002-3	PRC-004-WECC-1	PRC-020-1
CIP-002-3b	PRC-005-2	PRC-021-1
EOP-004-2	PRC-005-3	PRC-023-2
FAC-010-2.1	PRC-006-1	PRC-023-3
FAC-011-2	PRC-012-0	TOP-005-2a
IRO-005-3.1a	PRC-013-0	TPL-001-0.1
MOD-029-1a	PRC-014-0	TPL-002-0b
MOD-030-02	PRC-015-0	TPL-003-0b
NUC-001-2.1	PRC-016-0.1	TPL-004-0a
PRC-001-1.1	PRC-017-0	

[1] There are two provisions set forth in the Implementation Plan of PRC-023-3 that are specific to load-responsive phase protection systems on circuits identified by the Planning Coordinator pursuant to Requirement R6 remain in effect. (1) Each Transmission Owner, Generator Owner, and Distribution Provider in Requirements R2 and R3 shall become compliant the later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date, and (2) Requirement R1, Criterion 6 of PRC-023-2 shall remain in force until the effective date of PRC-025-1.

General Considerations

The entity shall modify its processes as necessary to account for the revised definition. The revised definition of RAS clarifies that it is inclusive of centrally controlled undervoltage-based load shedding. Entities may have additional changes to the classification of certain schemes to align them with the revised definition.

This Implementation Plan provides additional time for entities with newly classified RAS to become compliant with the Reliability Standards during the transition to the revised definition.

All aspects of the Implementation Plans for PRC-005-2 and PRC-005-3 will remain applicable to PRC-005-2(ii) and PRC-005-3(ii). These implementation plans are incorporated here by reference.

Prerequisite Approvals

NERC Reliability Standard PRC-010-1 – Undervoltage Load Shedding
Definition of "Undervoltage Load Shedding Program (UVLS Program)" in Project 2008-02 Undervoltage Load Shedding

Revisions to the NERC Glossary of Terms

The drafting team proposes the following revised definition:

Remedial Action Scheme (RAS)
A scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation (MW and Mvar), tripping load, or reconfiguring a System(s). RAS accomplish objectives such as:

- Meet requirements identified in the NERC Reliability Standards;
- Maintain Bulk Electric System (BES) stability;
- Maintain acceptable BES voltages;
- Maintain acceptable BES power flows;
- Limit the impact of Cascading or extreme events.

The following do not individually constitute a RAS:

a. Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating the faulted Elements

b. Schemes for automatic underfrequency load shedding (UFLS) and automatic undervoltage load shedding (UVLS) comprised of only distributed relays

c. Out-of-step tripping and power swing blocking

d. Automatic reclosing schemes

e. Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, overvoltage, or overload to protect the Element against damage by removing it from service

f. Controllers that switch or regulate one or more of the following: series or shunt reactive devices, flexible alternating current transmission system (FACTS) devices, phase-shifting transformers, variable-frequency transformers, or tap-changing transformers; and, that are located at and monitor quantities solely at the same station as the Element being switched or regulated

g. FACTS controllers that remotely switch static shunt reactive devices located at other stations to regulate the output of a single FACTS device

h. Schemes or controllers that remotely switch shunt reactors and shunt capacitors for voltage regulation that would otherwise be manually switched

i. Schemes that automatically de-energize a line for a non-Fault operation when one end of the line is open

j. Schemes that provide anti-islanding protection (e.g., protect load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage)

k. Automatic sequences that proceed when manually initiated solely by a System Operator

l. Modulation of HVdc or FACTS via supplementary controls, such as angle damping or frequency damping applied to damp local or inter-area oscillations

m. Sub-synchronous resonance (SSR) protection schemes that directly detect sub-synchronous quantities (e.g., currents or torsional oscillations)

n. Generator controls such as, but not limited to, automatic generation control (AGC), generation excitation [e.g., automatic voltage regulation (AVR) and power system stabilizers (PSS)], fast valving, and speed governing

Conforming Changes to Other Standards

The existing Reliability Standards proposed for retirement contain references to SPS or RAS or both. The revised Reliability Standards will reflect the use of the single term RAS. The revised Reliability Standards noted above for approval are included in a separate document *Revised Reliability Standards for the Revised Definition of "Remedial Action Scheme."*

Effective Date for Revised Reliability Standards and Definition

Except as noted below, the revised Reliability Standards and the revised definition of "Remedial Action Scheme" shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standards and definition are 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 standards and the definition shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standards and definition are adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Implementation Plan for Newly Classified Remedial Action Schemes (RAS)

Entities with newly classified "Remedial Action Scheme" (RAS) resulting from the application of the revised definition must be fully compliant with all Reliability Standards applicable RAS twenty-four (24)

months from the Effective Date of the revised definition of RAS. This additional time applies only to existing schemes that must transition to RAS due to the revised definition. The additional time does not apply to future RAS that may be created following implementation of the revised definition.

Retirement of Existing Standards and Definitions

The requested Reliability Standards for retirement shall be retired at midnight of the day immediately prior to the Effective Date of its successor standard in the particular jurisdiction in which the revised definition is becoming effective. The current definition of "Remedial Action Scheme" shall be retired at midnight of the day immediately prior to the Effective Date of the revised definition of "Remedial Action Scheme".

Exhibit B

Implementation Plan for the Revised Definition of “Remedial Action Scheme”

Clean Version

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan for the Revised Definition of "Remedial Action Scheme"

Project 2010-05.2 – Special Protection Systems

Background

The existing Glossary of Terms Used in NERC Reliability Standards definition for "Special Protection System" ("SPS") or "Remedial Action Scheme" ("RAS") lacks the specificity necessary to consistently identify what equipment or protection schemes qualify as SPS/RAS across the eight NERC Regions. The existing definition also does not clearly stipulate the characteristics of a SPS/RAS. The actions listed in the definition of SPS, which are incorporated by cross reference (NERC Glossary of Terms) into the definition of RAS, are ambiguous and may unintentionally include equipment whose purpose is not expressly related to preserving System reliability in response to predetermined System conditions. Employing a single term, i.e., RAS, and clarifying its definition will lead to more consistent application of the NERC Reliability Standards related to RAS.

The proposed definition of RAS must be broad to include the variety of System conditions monitored and corrective actions taken by RAS. Because of the diversity of RAS in both action and objective, the practical approach to the definition is to begin with a wide scope and then list specific exclusions. Without the exclusions, equipment and schemes that should not be considered RAS could be subject to the requirements of the RAS-related NERC Reliability Standards. The exclusion list assures that commonly applied protection and control systems are not unintentionally included as RAS.

The Project 2010-05.2 SPS SDT coordinated the development of the RAS definition with the development of PRC-010-1 by the SDT for Project 2008-02 – Undervoltage Load Shedding. The UVLS SDT introduced a new term, UVLS Program, into the Glossary of Terms Used in NERC Reliability Standards to clearly establish applicability of PRC-010-1. The proposed term UVLS Program is defined as: "An automatic load shedding program consisting of distributed relays and controls used to mitigate undervoltage conditions leading to voltage instability, voltage collapse, or Cascading impacting the Bulk Electric System (BES). Centrally controlled undervoltage-based load shedding is not included."

Note that the proposed definition excludes centrally controlled undervoltage-based load shedding. The UVLS SDT maintains that the design and characteristics of centrally controlled undervoltage-based load shedding are commensurate with RAS (wherein load shedding is the remedial action) and, as such, should be subject to RAS-related Reliability Standards. The Project 2010-05.2 SPS SDT agreed with this assessment and revised the definition of RAS to clarify that it is exclusive of distributed UVLS relays including the newly defined term UVLS Program. Therefore, the definition is inclusive of centrally controlled undervoltage-based load shedding. Collectively, the two definitions will promote consistency in the identification of centrally controlled undervoltage-based load shedding as RAS. The coordination of these revisions is required to maintain coverage of those systems and prevent a reliability gap. As a

result of these revisions, all NERC Reliability Standards that include the term RAS will be applicable to centrally controlled undervoltage-based load shedding upon the effective dates of the revised definitions of RAS and UVLS Program.

Requested Approvals

The definition of "**Remedial Action Scheme**" and the standards are listed below:

The following standards are proposed for approval to align the use of the single defined term RAS. This list is intended to reflect Reliability Standards currently in effect at the time of Project development. In certain cases, a standard listed below for approval may already be retired pursuant to an implementation plan of a successor version by the time the definition of "Remedial Action Scheme" becomes effective in a particular jurisdiction. In these cases, the standard below will not become effective.

CIP-002-3(i)	PRC-004-WECC-2	PRC-020-2
CIP-002-3(i)b	PRC-005-2(ii)	PRC-021-2
EOP-004-3	PRC-005-3(ii)	PRC-023-2(i)
FAC-010-3	PRC-006-1(i)	PRC-023-4[1]
FAC-011-3	PRC-012-1	TOP-005-3a
IRO-005-3.1(i)a	PRC-013-1	TPL-001-0.1(i)
MOD-029-2a	PRC-014-1	TPL-002-0(i)b
MOD-030-3	PRC-015-1	TPL-003-0(i)b
NUC-001-2.1(i)	PRC-016-1	TPL-004-0(i)a
PRC-001-1.1(i)	PRC-017-1	

Requested Retirements

CIP-002-3	PRC-004-WECC-1	PRC-020-1
CIP-002-3b	PRC-005-2	PRC-021-1
EOP-004-2	PRC-005-3	PRC-023-2
FAC-010-2.1	PRC-006-1	PRC-023-3
FAC-011-2	PRC-012-0	TOP-005-2a
IRO-005-3.1a	PRC-013-0	TPL-001-0.1
MOD-029-1a	PRC-014-0	TPL-002-0b
MOD-030-02	PRC-015-0	TPL-003-0b
NUC-001-2.1	PRC-016-0.1	TPL-004-0a
PRC-001-1.1	PRC-017-0	

[1] This Implementation Plan carries forward and incorporates by reference the following two provisions set forth in the Implementation Plan associated with Reliability Standard PRC-023-3 that are specific to load-responsive phase protection systems on circuits identified by the Planning Coordinator pursuant to Requirement R6: (1) Each Transmission Owner, Generator Owner, and Distribution Provider in Requirements R2 and R3 shall become compliant the later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date; and (2) Requirement R1, Criterion 6 of PRC-023-2 shall remain in force until the effective date of PRC-025-1.

General Considerations

The entity shall modify its processes as necessary to account for the revised definition. The revised definition of RAS clarifies that it is inclusive of centrally controlled undervoltage-based load shedding. Entities may have additional changes to the classification of certain schemes to align them with the revised definition.

This Implementation Plan provides additional time for entities with newly classified RAS to become compliant with the Reliability Standards during the transition to the revised definition.

All aspects of the Implementation Plans for PRC-005-2 and PRC-005-3 will remain applicable to PRC-005-2(ii) and PRC-005-3(ii). These implementation plans are incorporated here by reference.

Prerequisite Approvals

NERC Reliability Standard PRC-010-1 – Undervoltage Load Shedding
Definition of "Undervoltage Load Shedding Program (UVLS Program)" in Project 2008-02 Undervoltage Load Shedding

Revisions to the NERC Glossary of Terms

The drafting team proposes the following revised definition:

Remedial Action Scheme (RAS)
A scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation (MW and Mvar), tripping load, or reconfiguring a System(s). RAS accomplish objectives such as:

- Meet requirements identified in the NERC Reliability Standards;
- Maintain Bulk Electric System (BES) stability;
- Maintain acceptable BES voltages;
- Maintain acceptable BES power flows;
- Limit the impact of Cascading or extreme events.

The following do not individually constitute a RAS:

a. Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating the faulted Elements

b. Schemes for automatic underfrequency load shedding (UFLS) and automatic undervoltage load shedding (UVLS) comprised of only distributed relays

c. Out-of-step tripping and power swing blocking

d. Automatic reclosing schemes

e. Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, overvoltage, or overload to protect the Element against damage by removing it from service

f. Controllers that switch or regulate one or more of the following: series or shunt reactive devices, flexible alternating current transmission system (FACTS) devices, phase-shifting transformers, variable-frequency transformers, or tap-changing transformers; and, that are located at and monitor quantities solely at the same station as the Element being switched or regulated

g. FACTS controllers that remotely switch static shunt reactive devices located at other stations to regulate the output of a single FACTS device

h. Schemes or controllers that remotely switch shunt reactors and shunt capacitors for voltage regulation that would otherwise be manually switched

i. Schemes that automatically de-energize a line for a non-Fault operation when one end of the line is open

j. Schemes that provide anti-islanding protection (e.g., protect load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage)

k. Automatic sequences that proceed when manually initiated solely by a System Operator

l. Modulation of HVdc or FACTS via supplementary controls, such as angle damping or frequency damping applied to damp local or inter-area oscillations

m. Sub-synchronous resonance (SSR) protection schemes that directly detect sub-synchronous quantities (e.g., currents or torsional oscillations)

n. Generator controls such as, but not limited to, automatic generation control (AGC), generation excitation [e.g., automatic voltage regulation (AVR) and power system stabilizers (PSS)], fast valving, and speed governing

Conforming Changes to Other Standards

The existing Reliability Standards proposed for retirement contain references to SPS or RAS or both. The revised Reliability Standards will reflect the use of the single term RAS. The revised Reliability Standards noted above for approval are included in a separate document *Revised Reliability Standards for the Revised Definition of "Remedial Action Scheme."*

Effective Date for Revised Reliability Standards and Definition

Except as noted below, the revised Reliability Standards and the revised definition of "Remedial Action Scheme" shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standards and definition are 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 standards and the definition shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standards and definition are adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Implementation Plan for Newly Classified Remedial Action Schemes (RAS)

Entities with newly classified "Remedial Action Scheme" (RAS) resulting from the application of the revised definition must be fully compliant with all Reliability Standards applicable RAS twenty-four (24)

months from the Effective Date of the revised definition of RAS. This additional time applies only to existing schemes that must transition to RAS due to the revised definition. The additional time does not apply to future RAS that may be created following implementation of the revised definition.

Retirement of Existing Standards and Definitions

The requested Reliability Standards for retirement shall be retired at midnight of the day immediately prior to the Effective Date of its successor standard in the particular jurisdiction in which the revised definition is becoming effective. The current definition of "Remedial Action Scheme" shall be retired at midnight of the day immediately prior to the Effective Date of the revised definition of "Remedial Action Scheme".

1977-2017
CELEBRATING 40 YEARS
Federal Energy Regulatory Commission

NEWS RELEASE

September 20, 2017

News Media Contact

Craig Cano | 202-502-8680

Docket Nos. RM16-13-000, RM16-20-000, RM17-12-000

Item Nos. E-1, E-2, E-3

FERC Issues Final Rules to Enhance Bulk Electric System Resilience, Reliability

The Federal Energy Regulatory Commission (FERC) today approved two final rules and issued a Notice of Proposed Rulemaking (NOPR) addressing mandatory standards intended to support the resilience and reliability of the nation's bulk electric system.

One final rule approves revised reliability standards on Balancing Authority Control (BAL-005-1) and Facility Interconnection Requirements (FAC-001-3) that clarify and consolidate existing requirements related to frequency control. The revised standards will support more accurate and comprehensive calculation of Reporting Area Control Error.

The second final rule approves a revised reliability standard on Remedial Action Schemes (PRC-012-2) to ensure that remedial action schemes do not introduce unintentional or unacceptable reliability risks to the grid. It establishes a centralized process to review new or modified remedial action schemes before implementation by requiring periodic evaluations, tests and operational analyses of each remedial action scheme and an annual update of an area-wide remedial action scheme database. The final rule also assigns specific responsibilities to the appropriate functional entities.

Today's NOPR proposes to approve revised Emergency Preparedness and Operations reliability standards covering Event Reporting (EOP-004-4), System Restoration from Blackstart Resources (EOP-005-3), System Restoration Coordination (EOP-006-3) and Loss of Control Center Functionality (EOP-008-2). The proposed standards are intended to:

- Provide accurate reporting of events to the North American Electric Reliability Corp's event analysis group to examine the impact on reliability of the grid;
- Delineate the roles and responsibilities of entities that support system restoration from blackstart resources;
- Clarify the procedures and coordination requirements for reliability coordinator personnel to execute system restoration processes; and
- Refine the required elements of an operating plan used to continue reliable operation of the grid if primary control functionality is lost.

The final rules take effect, and comments on the NOPR are due, 60 days after publication in the *Federal Register*.

R-17-32

(30)

Clean
November 9, 2016

Scope of Work
for the
Regional Standards Committee (RSC)

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

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

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

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

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

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

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

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

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

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

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

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

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

RSC Members should make every effort to attend scheduled meetings and when not available are required to identify and provide a qualified proxy participant. RSC business cannot be conducted in the absence of a quorum and it is essential that each RSC member make a commitment to be present. A determination to recommend removal of a member shall be considered by the NPCC RSC Executive Committee if a member is excessively absent and provides no proxy for regularly scheduled meetings.

A. NPCC Regional Standards Process Responsibilities

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

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

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 Directory and Criteria related matters.

C. NERC Reliability Standards Responsibilities

The RSC will:

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

accordance with the CMEP Implementation Guidance Process.

D. FERC Activities Affecting Standards

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

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

Redlined
November 9, 2016

Scope of Work
for the
Regional Standards Committee (RSC)

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

(a) Managing the NPCC Regional Standards Development Process.
(b) Managing the NPCC Directory and Criteria Development and Review Process.
(c) Providing consolidated NPCC Regional review and comments to existing and proposed NERC Standards in accordance with the NERC Reliability Standards Development Process.
(d) Reviewing FERC Orders, Rulings and Notice of Proposed Rulemakings (NOPRs) related to Reliability Standards, by providing a forum for developing consensus viewpoints and submitting comments to FERC if necessary.
(e) Reviewing NERC Reliability Standard Audit Worksheets (RSAWs) in coordination with the NPCC Compliance Committee (CC) and submitting comments to NERC if necessary.
(f) Providing consolidated NPCC Regional review and comment to the existing and proposed NERC Standards Development Processes Manual and to the NERC Rules of Procedure as they relate to Standards Development.
(g) Determining the need for and development of NERC and Regional Standards, Variances to NERC Standards, modifications to NPCC Directories~~,~~ and Criteria, and/or interpretations and clarifications thereof.
(h) In coordination with the CC, address issues identified through the NPCC Feedback Mechanism to continually improve standards and NERC documents such as Guidelines and other technical material.
(i~~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 consensus Regional 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 Program Area Staff which will administer actions as denoted in the NPCC Regional Standard~~s~~ Processes Manual and coordinate the review and submission of all standards related comments pursuant to the NERC Standards Development Processes Manual and the NERC R~~r~~ules of Procedure.

Commented [HS1]: Should the discussion highlighted in HS 2 below be moved up here?

The RSC will be chaired and assisted 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 the~~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 RSC Executive Committee will assist in management of the RSC and will be comprised of the Chair, the Co-vice Chairs and two elected RSC members (the two elected RSC members will be comprised of a Canadian representative and a U.S. representative). Additionally, the two RSC members elected to the RSC Executive Committee by the RSC membership will serve for a two-year term.

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

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

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

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

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

RSC Members should make every effort to attend scheduled meetings and when not available are required to identify and provide a qualified proxy participant. RSC business cannot be conducted in the absence of a quorum and it is essential that each RSC member make a commitment to be present. A determination to recommend removal of a member shall be considered by the NPCC RSC Executive Committee if a member is excessively absent and provides no proxy for regularly scheduled meetings.

A. NPCC Regional Standards Process Responsibilities

The RSC is responsible for managing the standards process for the development of ERO 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.

Commented [HS2]: Sould this be moved up to the section first discussing the role of the RSC in the standards process?

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.

Commented [HS3]: Should this not say the RSC operates largely by consensus and that if a vote is needed it will be done in accordance with the Bylaws?

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

D. FERC Activities Affecting Standards

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

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

NPCC, Inc.

Clean
November 9th, 2016

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

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

NPCC Reliability Standards Committee Program Responsibilities (related to Standards)

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

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

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

NERC Standard Drafting Teams and additional members to the regional drafting teams. Ensure sufficient regional representation exists on the drafting teams.

27. Educate and notify NPCC Region stakeholders and regulators about issues related to Standards development.
28. Participate in two scheduled NPCC Compliance and Standards Workshops
29. Participate in the revision and redrafting of the NERC Rules and Procedures and other documents related to standards development such as, but not limited to:
    a. The NERC Functional Model Working Group (FMWG)
    b. The NERC Regional Standards Group (RSG)
    c. The NERC Standards Committee (SC)
    d. The NERC Standards Committee Process Subcommittee (SCPS)
30. Coordinate implementation of the NERC Standards development processes and NPCC regional Standard processes and recommend revisions as necessary.

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

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

The activities listed in this work plan are based on the current planned execution of the NERC Reliability Standards Development Plan (RSDP), proposed strategic direction of the NPCC BOD and NERC BOT as well as additional Directives from the FERC Orders. Changes to these programs, the NERC RSDP, the NERC Rules of Procedure, or the NPCC Standards or Directory processes may necessitate changes to listed activities, including revised scheduling of the activities, removal of certain activities, and/or the addition of activities. If significant changes occur during the course of the year, the RSC Work Plan will be revised in advance of the NPCC Board of Director's annual review and will be forwarded to the NPCC Board of Directors for approval.

Redlined
November 9th, 2016

Northeast Power Coordinating Council, Inc.
Regional Standards Committee
Work Plan for Calendar Years 2016~~6~~7-2017~~7~~8

The following Regional Standards Committee (RSC) Work Plan activities for the calendar years of 2016~~6~~7 - 2017~~7~~8 will be consistent with the NPCC 2016~~6~~7 and 2017~~7~~8 Business Plans and Budgets, Organizational and Strategic Goals, both approved and in draft, and will also continue to be supportive of the ongoing cost effective enhanced periodic reviews and results based standard development ~~efforts~~activities. Also, the Work Plan is responsive to the NERC Reliability Standards Development Process and ERO strategic goals. In 2016~~6~~7-2017~~7~~8, expedited standards project schedules as a result of ~~due to~~ FERC Orders ~~and issued~~ Ddirectives and ~~as well as~~ the NERC Board of Trustees goal of~~and enhanced periodic reviews of standards with the goal of~~ achieving a "steady-state" for reliability ~~of~~ standards ~~development~~ will be the focus of the RSC.

~~Core~~ NPCC Reliability Standards Committee Program Responsibilities (related to Standards)~~Functions~~

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

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

Formatted: Left

Formatted: Numbered + Level: 1 + Numbering Style: 1, 2, 3, … + Start at: 1 + Alignment: Left + Aligned at: 0.25" + Indent at: 0.5"

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

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

Formatted: Numbered + Level: 2 + Numbering Style: a, b, c, … + Start at: 1 + Alignment: Left + Aligned at: 0.75" + Indent at: 1"

7. ~~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 and provide technical and policy related opinions as necessary~~ Engage in the newly approved NERC Compliance Policy Guidance program. Support the inputs through the NPCC Compliance Committee by providing technical and policy related opinions as necessary.~~.~~
8. ~~Coordinate NPCC Regional Standards development activity with the development of NERC standards developments proposedappearing in the NERC Reliability Standards Development Plan to ensure resources are available for efficient and effective standards development and implementationexecution.~~Coordinate NPCC Regional Standards development activity with NERC Standards development activity to ensure resources are available for efficient and effective standards development and implementation.
9. Coordinate NPCC participation in the review and the revision of NERC Standards and addressing reliability directives from FERC's Orders and any Provincial regulatory directives through the Enhanced Periodic Review process. Specifically, and of the highest importance:
    a. Reliability Standards activity resulting from FERC Order 860 Geomagnetic Disturbances (GMD)
    b. Single Points of Failure
    c. Modifications to CIP Standards
    d. Cyber Security Supply Chain Management
    e. Establish and Communicate System Operating Limits
    f. and any other similar activity which may evolve during the course of the year.
10. Address emerging issues FERC has identified ~~might have~~ with the NPCC Regional Standard Processes to promote consistency and support of the ERO One Enterprise model.
11. Conduct thorough reviews of all NERC Standards being developed or revised~~,~~ and coordinate timely comments within the NPCC Region based on reliability needs, results based requirements, Paragraph 81, FERC directives and Enhanced Periodic Reviews.
12. Develop and submit Standard Authorization Requests (SARs) for revisions when necessary to improve a Standard and address reliability related issues for approved or draft Standards utilizing input from the NPCC Regional Feedback Mechanism to improve the quality and efficacy of standards.
13. Develop ballot recommendations or "issues statements" for all NERC Standards under development.
14. Review and develop ballot recommendations for all NERC ~~f~~Formal ~~i~~Interpretations to Standards.
- Identify candidates for NERC Standards Drafting Team members from the NPCC region to ensure ~~provide~~ regional representation ~~the NPCC perspective~~ during the development of the respective Standards.~~to NERC's on Standards development program.~~
15. Provide guidance to NPCC regional Standard Drafting Teams in critical areas of results-based Standards, Violation Severity Levels, and Violation Risk Factor development as well as ensuring quality.
16. Respond to FERC and Provincial filings and interrogatories on issues related to regional Standards.
17. Serve as a liaison for the Northeast Region to the NERC Reliability Issues Steering Committee for all new and emerging reliability risks to the BES.
18. Participate in the proceedings of various NERC groups to contribute to the continual improvement of NERC Standards and processes. These groups include but are not limited to:
    ~~0~~a. NERC Standards Committee (SC)
    ~~0~~b. NERC Standards Committee Process Subcommittee (SCPS)
    ~~0~~c. NERC Project Management Oversight Subcommittee (PMOS)
    ~~0~~d. NERC Functional Model Advisory Group (FMAG)
    ~~0~~e. NERC SAR and Standards Drafting Teams (SDTs)
    ~~0~~f. NERC Reliability Issues Steering Committee (RISC)

Formatted: Numbered + Level: 1 + Numbering Style: 1, 2, 3, … + Start at: 1 + Alignment: Left + Aligned at: 0.25" + Indent at: 0.5"

Formatted: Numbered + Level: 2 + Numbering Style: a, b, c, … + Start at: 1 + Alignment: Left + Aligned at: 0.75" + Indent at: 1"

Formatted: Numbered + Level: 1 + Numbering Style: 1, 2, 3, … + Start at: 1 + Alignment: Left + Aligned at: 0.25" + Indent at: 0.5"

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

Formatted: Numbered + Level: 2 + Numbering Style: a, b, c, … + Start at: 1 + Alignment: Left + Aligned at: 0.75" + Indent at: 1"

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

19. Manage the development and revision of the regional reliability Directories including criteria clarifications as necessary and review all criteria to ensure consistency with NERC or regional Reliability Standards.
20. Promote the NPCC criteria as ~~being more specific or more stringent~~augmenting and providing specificity to NERC standards requirements or addressing issues not covered in existing NERC standards. Coordinate efforts with the NPCC Compliance Committee to facilitate further development of the NPCC Criteria Compliance Enforcement Program (CCEP) via Phase 2 of the Directory Project which was initiated to reformat the criteria section of each Directory into measurable NERC-style requirements.
21. Develop proposed standards and standard clarifications utilizing regional technical committees as assigned by the NPCC Reliability Coordinating Committee, RSC or as identified through the NPCC Regional Feedback Mechanism.
22. Work with the NPCC CC to develop the necessary compliance elements of the regional Standards, for example, Violation Severity Levels (VSLs).
23. Implement the NPCC Cost Effective Analysis Procedure and apply it to Directories being revised or developed, and promote and participate in the NERC Cost of Risk Reduction Analysis (CRRA) application to the ERO draft continent-wide Standards.
24. Review NERC SARs, Standards, and interpretations, and provide comments as well as participate in NERC stakeholder processes.
25. Ensure that the appropriate NPCC Task Forces review NERC Standards-related issuances, and provide input to support development of a NPCC consensus opinion.
26. Solicit technically qualified candidates from NPCC stakeholder companies to participate on each of the NERC Standard Drafting Teams and additional members to the regional drafting teams. Ensure sufficient regional representation exists on the drafting teams.
27. Educate and notify NPCC Region stakeholders and regulators about issues related to Standards development. Participate in two scheduled NPCC Compliance and Standards Workshops
28. Participate in the revision and redrafting of the NERC Rules and Procedures and other documents related to standards development such as, but not limited to:
    a. The NERC Functional Model Working Group (FMWG)
    b. The NERC Regional Standards Group (RSG)
    c. The NERC Standards Committee (SC)
    d. The NERC Standards Committee Process Subcommittee (SCPS)
29. Coordinate implementation of the NERC Standards development processes and NPCC regional Standard processes and recommend revisions as necessary.

~~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).~~

Formatted: Numbered + Level: 1 + Numbering Style: 1, 2, 3, ... + Start at: 1 + Alignment: Left + Aligned at: 0.25" + Indent at: 0.5"

Formatted: Numbered + Level: 1 + Numbering Style: 1, 2, 3, ... + Start at: 1 + Alignment: Left + Aligned at: 0.25" + Indent at: 0.5"

Formatted: Font color: Auto

Formatted: Font: 10 pt

Formatted: Default, Numbered + Level: 1 + Numbering Style: 1, 2, 3, ... + Start at: 1 + Alignment: Left + Aligned at: 0.25" + Indent at: 0.5", No widow/orphan control, Adjust space between Latin and Asian text, Adjust space between Asian text and numbers, Tab stops: Not at 0.75"

Formatted: Font: 10 pt

Formatted: Default, Numbered + Level: 1 + Numbering Style: 1, 2, 3, ... + Start at: 1 + Alignment: Left + Aligned at: 0.25" + Indent at: 0.5", No widow/orphan control, Adjust space between Latin and Asian text, Adjust space between Asian text and numbers

Formatted: Font: 10 pt

Formatted: Font: 10 pt

Formatted: Font: 10 pt

Formatted: Font: 10 pt

Formatted: Numbered + Level: 1 + Numbering Style: 1, 2, 3, ... + Start at: 1 + Alignment: Left + Aligned at: 0.25" + Indent at: 0.5"

Commented [HS4]: Perhaps this one should be a separate item?

Formatted

Commented [HS5]: Perhaps this one should be moved up to HS 1 comment.

Formatted: No bullets or numbering

- ~~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.~~

Formatted: Widow/Orphan control

Formatted: Widow/Orphan control

Formatted: Widow/Orphan control, Tab stops: 1.75", Left + Not at 1.63"

Formatted: Widow/Orphan control, Tab stops: 1.75", Left + Not at 1.63"

Formatted: Default, Tab stops: 1.75", Left

Formatted: Widow/Orphan control, Tab stops: 1.75", Left

Formatted: Widow/Orphan control, Tab stops: Not at 1.25"

Formatted: Widow/Orphan control, Tab stops: 1.75", Left

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

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

1. Coordinate Directory ~~activities~~Development activities with the regulatory authorities in the U.S. and ~~all~~ applicable Provincial authorities~~ for NPCC Directories~~.
2. Identify the need for new or modified NPCC Directories and the Ceriteria, Guidelines and Procedures within ~~or guidelines~~ pursuant to Section 313 of the NERC ROP responsibilities
3. Oversee the development or modification of Directories in accordance with the NPCC Directory Development and Revision Manual
4. Coordinate Directory criteria requirements with regional and NERC Standards requirements to ensure no inconsistencies exist and identify potential areas for improvements.
5. Develop filing for the Directories for the New York State Public Service Commission to fulfill obligations for the "Carve-out" outlined in Order 672 for mandatory adherence to more stringent regional criteria for New York State.
6. Develop filings of Directories as required with the Provincial authorities as per the various Memorandums of Understanding.
7. Communications
    - ~~0~~a. Announce ~~D~~development ~~and maintain~~activities pertaining to the NPCC Reliability Directories and NPCC guidance documents which will enable users, owners and operators of the ~~international~~ Bulk Power System in the Region to be aware of and apply the ~~more stringent~~ NPCC regionally-specific criteria.
    - ~~0~~b. Identify future regional Standard development or retirement opportunities by developing a set of regional reliability Directories incorporating the ERO Reliability Standards, regional Standards and regionally-specific more stringent criteria.

~~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.~~

The activities listed in this work plan are based on the current planned execution of the NERC Reliability Standards Development Plan (RSDP), proposed strategic direction of the NPCC BOD and NERC BOT as well as additional Directives from the FERC Orders. Changes to these programs, the NERC RSDP, the NERC Rules of Procedure, or the NPCC Standards or Directory processes may necessitate changes to listed activities, including revised scheduling of the activities, removal of certain activities, and/or the addition of activities. If significant changes occur during the course of the year, the ~~the~~ RSC Work Plan will be revised in advance of the NPCC Board of Director's annual review and will be forwarded to the NPCC Board of Directors for approval.

Formatted: Widow/Orphan control

Formatted: Left

Formatted: Numbered + Level: 1 + Numbering Style: 1, 2, 3, … + Start at: 1 + Alignment: Left + Aligned at: 0.25" + Indent at: 0.5"

Commented [HS6]: Confirm – is this is a NPCC bylaw section? If so, say it. Otherwise, what is it. Or is it a NPCC member agreement section?

Formatted: Numbered + Level: 2 + Numbering Style: a, b, c, … + Start at: 1 + Alignment: Left + Aligned at: 0.75" + Indent at: 1"

Commented [HS7]: Not sure I understand this one. Perhaps we should discuss intention during the meeting.

Formatted: Indent: Left: 0.5"

NERC's Reliability Issues Steering Committee RISC

Guy V. Zito
NPCC RSC
October 11-12, 2017

Overview

- Background
- RISC Process
- 2017 RISC Report
- Risk Groupings
- Risk Profiles
- 2017 RISC Report Schedule
- Questions and answers

Background

- Purpose of the RISC
  - Advisory committee to the NERC Board of Trustees BOT
  - Provides insights into key reliability concerns
  - Identifies goals and objectives for solutions
  - Provides guidance and suggestions
  - Efficient use of resources
  - Standards vs. guidelines
- Publishes a full report every two years for BOT approval
  - Public comment periods
  - Risk Profiles
  - Input and recommended actions
  - Provides input to the ERO Long Term Strategic Plan, Operating Plan, and NERC Business Plan and Budget
  - Advises the ERO action planning process

RISC Process

- Gather input from FERC Technical Conference, NERC Leadership Summit, MRC and other industry input on risk
- Conduct “Pulse Point” Interviews
- Categorize/group Risk Profiles (High Medium or Low)
- Develop actions the ERO should undertake for each Risk
- Identify common themes and “map” the risks
- Develop recommendations (near term, mid term and long term) for each risk
- Compile information and draft a report
- Post for comment
- Finalize report and seek BOT approval

2017 RISC Groupings

High Risk Profiles

High likelihood and higher impact on the BPS focus was needed to fully understand the risks to address them

Moderate Risk Profiles

Generally a high impact but a lower probability, risk and mitigations understood

Low Risk Profiles

Lower impact to reliability and moderate probably but fully understood and generally addressed

2017 RISC Profiles

Each Risk Profile has the following:

- Statement of the Risk-high level description
- Level of Risk (high medium or low)
- Descriptors of the Risk
- Recommendations for Mitigating the Risk-activities
    - Near-term (1-2 year timeframe)
    - Mid-term (3-5 year timeframe)
    - Long-term (longer than 5 year timeframe
- Recommendations beyond ERO Enterprise i.e. policymakers

2017 RISC Report

High Risk Profiles

- Cybersecurity Vulnerabilities
- Changing Resource Mix
- BPS Planning
- Resource Adequacy

Moderate Risk Profiles

- Loss of Situational Awareness
- Physical Security Vulnerabilities
- Extreme Natural Events

Low Risk Profiles

- Asset Management and Maintenance
- Human Performance and Skilled Workforce

2017 RISC Report Schedule

- Post for 45 day industry comment period mid-September 8(?) 2017
- RISC to review comments at November 8th meeting
- RISC to finalize 2017 Report in January 2018
- RISC to submit the 2017 Report to the NERC BOT for approval at the February 7, 2018 meeting

Questions ??

DOE Form- DRAFT OE-417 Review

Sean Bodkin, Connie Lowe – Dominion Energy

Dominion Energy

Agenda

- Review posting of DOE Draft OE-417
- Review the suggested changes in the Draft version of OE-417, in comparison to EOP-004-4 (pending FERC approval)
- Review OE-417 Draft document
- Discussion/Comments/Questions

DOE Draft OE-417

On August 16, 2017 the Department of Energy (DOE) asked for comments on the current proposed draft of the OE-417 report. This is an event based report similar to the EOP-004-4 Attachment 1 report.

A link to the current OE-417: DOE OE 417.

The stated purpose of the OE-417 form (from the DOE website) is as follows:

"The Electric Emergency Incident and Disturbance Report (Form OE-417) collects information on electric incidents and emergencies. The Department of Energy uses the information to fulfill its overall national security and other energy emergency management responsibilities, as well as for analytical purposes."

Below are links to the DOE OE-417 posting out for comment;

https://s3.amazonaws.com/public-inspection.federalregister.gov/2017-17255.pdf

https://www.gpo.gov/fdsys/pkg/FR-2017-08-16/pdf/2017-17255.pdf

Comments are due back to the DOE by October 16, 2017

The NERC EOP Standards Drafting Team (Project 2015-08) worked very closely with the DOE to develop a 'one stop reporting' form for entities to use for both DOE and EOP-004-4 reporting. The proposed OE-417 changes closely mirror the proposed EOP-004-4 Attachment 1.

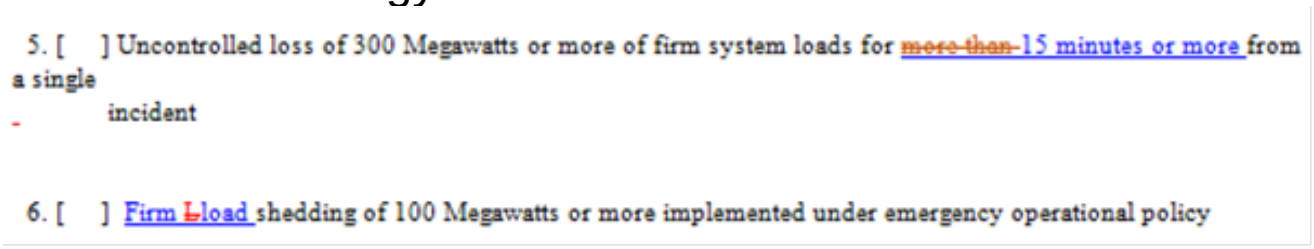
Draft OE-417 proposed changes compared to EOP-004-4

1. The instructions include a note that ‘‘NERC has determined that, for U.S. NERC reporting entities, the proposed revised Form OE–417 meets NERC’s submittal requirements’’ (*i.e.* Form EOP–004).

2. Alternative methods of filing Form OE–417 are added to allow the use of email submissions; however, online submissions remain the preferred method.

3. Under ‘‘Criteria for Filing,’’ three categories of submission will be shown: ‘‘Emergency Alert; Normal Report; System Report’’ to provide better clarity and easy reference. Reporting for criteria types will still be 1 hour and 6 hour, a 24 hour reporting will be added for the System Report to accommodate the additional EOP event types that were not already included in the OE-417.

4. Minor edits were made to the Alert criteria 5 and 6 to align with EOP–004-4 Reliability Standard terminology.



5. [ ] Uncontrolled loss of 300 Megawatts or more of firm system loads for ~~more than~~ 15 minutes or more from a single incident

6. [ ] Firm ~~L~~load shedding of 100 Megawatts or more implemented under emergency operational policy

Dominion Energy

Draft OE-417 proposed changes compared to EOP-004-4 (continued);

5. Under ‘‘Criteria for Filing’’ section: 12 new data elements are added to collect the additional information that NERC collects or will collect on under the EOP–004-4 Reliability Standard. The additional questions are in a new category of submission called ‘‘System Report’’. These new data elements will be reported within 24 hours of recognition (same as EOP-004-4). The additions are the exact same wording of events/thresholds from EOP-004-4 Attachment 1, with only a couple of minor changes as noted below;

a. 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 Bulk Electric System Emergency;

b. Damage or destruction of its Facility that results from actual or suspected intentional human action; (From EOP-004-4 the threshold has this additional statement –“It is not necessary to report theft unless it degrades normal operation of its Facility”; the DOE did not add this statement to the OE-417, as they did not feel it was needed)

Draft OE-417 suggested changes compared to EOP-004-4 continued;

c. 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 its Facility;

d. Physical threat to its Bulk Electric System 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 its Bulk Electric System control center;

e. Bulk Electric System Emergency resulting in voltage deviation on a Facility; a voltage deviation of equal to or greater than 10% of nominal voltage sustained for greater than or equal to 15 continuous minutes;

f. Uncontrolled loss of 200 Megawatts or more of firm system loads for 15 minutes or more from a single incident for entities with previous year's peak demand less than or equal to 3,000 Megawatts;

Draft OE-417 suggested changes compared to EOP-004-4 continued;

g. Total generation loss, within one minute of: Greater than or equal to 2,000 Megawatts in the Eastern or Western Interconnection or greater than or equal to 1,400 Megawatts in the ERCOT Interconnection; (DOE did not include Quebec in 2000 MWs generation loss reporting (as listed in EOP-004-4), as this report is for US entities only).

h. Complete loss of off-site power (LOOP) affecting a nuclear generating station per the Nuclear Plant Interface Requirements;

i. Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing);

j. Unplanned evacuation from its Bulk Electric System control center facility for 30 continuous minutes or more;

k. Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability affecting its staffed Bulk Electric System control center for 30 continuous minutes or more;

Draft OE-417 suggested changes compared to EOP-004-4 continued;

k. Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability affecting its staffed Bulk Electric System control center for 30 continuous minutes or more;

l. Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more.

6. Re-labeled line numbers 1 through 20 to line numbers A through T to prevent confusion between line numbers and alert criteria. This change in the published request for comments is not in the draft OE-417 form provided by DOE.

7. Added an Alert status category ‘‘system report,’’ which shall be filed by the later of 24 hours after the recognition of the incident OR by the end of the next business day. This change aligns with the EOP–004 Reliability Standard. 4:00 p.m. local time will be definition for the end of the business day. This is phrased differently but intent is the same.

Draft OE-417 suggested changes compared to EOP-004-4 continued;

8. Under Electric Emergency Incident and Disturbance Report section, lines J, K, L were reorganized into ‘‘Cause, Impact, and Action Taken’’ for clarity and ease of use and additional items were added to align with NERC’s EOP– 004 Reliability Standard. Minor changes and additions made to better conform with EOP-004-4 event categories.

9. The burden per response for completing Form OE–417 is reduced from 2.16 hours to 1.8 hours based on findings from the results from cognitive research conducted by the U.S. Energy Information Administration.

DOE Draft OE-417 with highlighted changes

U.S. Department of Energy Electricity Delivery and Energy Reliability Form OE-417	*ELECTRIC EMERGENCY INCIDENT AND DISTURBANCE REPORT*	OMB No. 1901-0288 Approval Expires: xx/xx/xxx Burden Per Response: 1.8 hours

NOTICE: This report is **mandatory** under Public Law 93-275. Failure to comply may result in criminal fines, civil penalties and other sanctions as provided by law. For the sanctions and the provisions concerning the confidentiality of information submitted on this form, see General Information portion of the instructions. **Title 18 USC 1001 makes it a criminal offense for any person knowingly and willingly to make to any Agency or Department of the United States any false, fictitious, or fraudulent statements as to any matter within its jurisdiction.**

RESPONSE DUE:

Within 1 hour of the incident, submit Schedule 1 and lines 13-17 in Schedule 2 as an Emergency Alert report if criteria 1-8 are met.

Within 6 hours of the incident, submit Schedule 1 and lines 13-17 in Schedule 2 as a Normal Report if only criteria 9-12 are met.

By the later of 24 hours after the recognition of the incident OR by the end of the next business day submit Schedule 1 & lines 13-17 in Schedule 2 as a System Report if criteria 13-24 are met. *Note: 4:00pm local time will be considered the end of the business day*

Submit updates as needed and/or a final report (all of Schedules 1 and 2) within 72 hours of the incident.

For NERC reporting entities registered in the United States; NERC has approved that the form OE-417 meets the submittal requirements for NERC. There may be other applicable regional, state and local reporting requirements.

METHODS OF FILING RESPONSE

(Retain a completed copy of this form for your files.)

Online:	Submit form via online submission at: https://www.oe.netl.doe.gov/OE417/
FAX:	FAX Form OE-417 to the following facsimile number: (202) 586-8485.
Alternate:	If you are unable to submit online or by fax, forms may be e-mailed to doehqeoc@hq.doe.gov, or call and report the information to the following telephone number: (202) 586-8100.

Dominion Energy

DOE Draft OE-417 with highlighted changes

SCHEDULE 1 -- ALERT CRITERIA

(Page 1 of 4)

Criteria for Filing (Check all that apply)
See Instructions For More Information

EMERGENCY ALERT **File within 1-Hour** If any box 1-8 on the right is checked, this form must be filed within 1 hour of the incident; check Emergency Alert (for the Alert Status) on **Line A** below.	1. [ ] Physical attack that causes major interruptions or impacts to critical infrastructure facilities or to operations 2. [ ] Cyber event that causes interruptions of electrical system operations 3. [ ] Complete operational failure or shut-down of the transmission and/or distribution electrical system 4. [ ] Electrical System Separation (Islanding) where part or parts of a power grid remain(s) operational in an otherwise blacked out area or within the partial failure of an integrated electrical system 5. [ ] Uncontrolled loss of 300 Megawatts or more of firm system loads for 15 minutes or more from a single incident 6. [ ] Firm load shedding of 100 Megawatts or more implemented under emergency operational policy 7. [ ] System-wide voltage reductions of 3 percent or more 8. [ ] Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the electric power system
NORMAL REPORT **File within 6-Hours** If any box 9-12 on the right is checked AND none of the boxes 1-8 are checked, this form must be filed within 6 hours of the incident; check Normal Alert (for the Alert Status) on **Line A** below.	9. [ ] Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems 10. [ ] Cyber event that could potentially impact electric power system adequacy or reliability 11. [ ] Loss of electric service to more than 50,000 customers for 1 hour or more 12. [ ] Fuel supply emergencies that could impact electric power system adequacy or reliability

DRAFT

Dominion Energy

DOE Draft OE-417 with highlighted changes

SCHEDULE 1 -- ALERT CRITERIA -- CONTINUED

(Page 2 of 4)

SYSTEM REPORT
File within 1-Business Day

If any box 13-24 on the right is checked AND none of the boxes 1-12 are checked, this form must be filed by the later of 24 hours after the recognition of the incident OR by the end of the next business day. *Note:* 4:00pm local time will be considered the end of the business day. Check System Alert (for the Alert Status) on **Line A** below.

13. [ ] 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 Bulk Electric System Emergency.

14. [ ] Damage or destruction of its Facility that results from actual or suspected intentional human action.

15. [ ] 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 its Facility.

16. [ ] Physical threat to its Bulk Electric System 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 its Bulk Electric System control center.

17. [ ] Bulk Electric System Emergency resulting in voltage deviation on a Facility; A voltage deviation of equal to or greater than 10% of nominal voltage sustained for greater than or equal to 15 continuous minutes.

18. [ ] Uncontrolled loss of 200 Megawatts or more of firm system loads for 15 minutes or more from a single incident for entities with previous year's peak demand less than or equal to 3,000 Megawatts

19. [ ] Total generation loss, within one minute of: greater than or equal to 2,000 Megawatts in the Eastern or Western Interconnection or greater than or equal to 1,400 Megawatts in the ERCOT Interconnection.

20. [ ] Complete loss of off-site power (LOOP) affecting a nuclear generating station per the Nuclear Plant Interface Requirements.

21. [ ] Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing).

22. [ ] Unplanned evacuation from its Bulk Electric System control center facility for 30 continuous minutes or more.

23. [ ] Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability affecting its staffed Bulk Electric System control center for 30 continuous minutes or more.

24. [ ] Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more.

If significant changes have occurred after filing the initial report, re-file the form with the changes and check Update (for the Alert Status) on **Line A** below.

The form must be re-filed within 72 hours of the incident with the latest information and Final (Alert Status) checked on **Line A** below, unless updated

DRAFT

Dominion Energy

DOE Draft OE-417 with highlighted changes

LINE NO.						
A.	Alert Status (check one)	Emergency Alert [ ] 1 Hour	Normal Report [ ] 6 Hours	System Report [ ] 1 Business Day	Update [ ] As required	Final [ ] 72 Hours
B.	Organization Name					
C.	Address of Principal Business Office					

DRAFT

Dominion Energy

DOE Draft OE-417 with highlighted changes – Minor wording changes to types of emergencies listed in J, K, and L

U.S. Department of Energy Electricity Delivery and Energy Reliability Form OE-417	*ELECTRIC EMERGENCY INCIDENT AND DISTURBANCE REPORT*	OMB No. 1901-0288 Approval Expires: xx/xx/xxx Burden Per Response: 1.8 hours

SCHEDULE 1 -- ALERT NOTICE

(Page 3 of 4)

INCIDENT AND DISTURBANCE DATA

D.	Geographic Area(s) Affected (County, State)			
E.	Date/Time Incident Began (mm-dd-yy/hh:mm) using 24-hour clock	____ - ____ - ____ / ____ : ____ mo dd yy hh mm	[ ] Eastern [ ] Central [ ] Mountain [ ] Pacific [ ] Alaska [ ] Hawaii	
F.	Date/Time Incident Ended (mm-dd-yy/ hh:mm) using 24-hour clock	____ - ____ - ____ / ____ : ____ mo dd yy hh mm	[ ] Eastern [ ] Central [ ] Mountain [ ] Pacific [ ] Alaska [ ] Hawaii	
G.	Did the incident/disturbance originate in your system/area? (check one)	Yes [ ]	No [ ]	Unknown [ ]
H.	Estimate of Amount of Demand Involved (Peak Megawatts)		Zero [ ]	Unknown [ ]
I.	Estimate of Number of Customers Affected		Zero [ ]	Unknown [ ]

SCHEDULE 1 – TYPE OF EMERGENCY

Check all that apply

J. Cause	K. Impact	L. Action Taken
☐ Unknown ☐ Physical attack ☐ Threat of physical attack ☐ Vandalism	☐ None ☐ Control center loss, failure, or evacuation ☐ Loss or degradation of control center monitoring or communication systems ☐ Damage or destruction of a facility ☐ Electrical system separation (islanding) ☐ Complete operational failure or shutdown of the transmission and/or distribution system	☐ None ☐ Shed Firm Load: Load shedding of 100 MW or more implemented under

DRAFT

Discussion/Comments/Questions

- **Reminder comments due October 16, 2017**
- **The DOE also plans to post another comment period for the DRAFT OE-417 during November 2017 (30 day comment period)**
- **The current OE-417 form expires 3/31/2018 and will be replaced with the final approved DOE version of the OE-417.**
- **Reminder – after the new OE-417 is posted near/around 3/31/2018, and until the EOP-004-4 is approved/implemented, you may have to submit 2 different forms (OE-417, EOP-004-3 Attachment 1)**
  - **Depending on the event , you could have to use one or the other form for reporting**
  - **After EOP-004-4 is implemented, then the OE-417 should be able to be used for all NERC and DOE reporting**

Discussion/Comments/Questions

Link to EOP-004-4;
http://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-004-4.pdf

Contact information; connie.lowe@dominionenergy.com
or sean.bodkin@dominionenergy.com

Dominion Energy

U.S. Department of Energy Electricity Delivery and Energy Reliability Form OE-417	*ELECTRIC EMERGENCY INCIDENT AND DISTURBANCE REPORT*	OMB No. 1901-0288 Approval Expires: xx/xx/xxx Burden Per Response: 1.8 hours

NOTICE: This report is **mandatory** under Public Law 93-275. Failure to comply may result in criminal fines, civil penalties and other sanctions as provided by law. For the sanctions and the provisions concerning the confidentiality of information submitted on this form, see General Information portion of the instructions. **Title 18 USC 1001 makes it a criminal offense for any person knowingly and willingly to make to any Agency or Department of the United States any false, fictitious, or fraudulent statements as to any matter within its jurisdiction**.

RESPONSE DUE:

Within 1 hour of the incident, submit Schedule 1 and lines 13-17 in Schedule 2 as an Emergency Alert report if criteria 1-8 are met.
Within 6 hours of the incident, submit Schedule 1 and lines 13-17 in Schedule 2 as a Normal Report if only criteria 9-12 are met.
By the later of 24 hours after the recognition of the incident OR by the end of the next business day submit Schedule 1 & lines 13-17 in Schedule 2 as a System Report if criteria 13-24 are met. *Note: 4:00pm local time will be considered the end of the business day*

Submit updates as needed and/or a final report (all of Schedules 1 and 2) within 72 hours of the incident.
For NERC reporting entities registered in the United States; NERC has approved that the form OE-417 meets the submittal requirements for NERC. There may be other applicable regional, state and local reporting requirements.

METHODS OF FILING RESPONSE

(Retain a completed copy of this form for your files.)

Online: Submit form via online submission at: https://www.oe.netl.doe.gov/OE417/
FAX: FAX Form OE-417 to the following facsimile number: (202) 586-8485.
Alternate: If you are unable to submit online or by fax, forms may be e-mailed to doehqeoc@hq.doe.gov, or call and report the information to the following telephone number: (202) 586-8100.

SCHEDULE 1 -- ALERT CRITERIA

(Page 1 of 4)

Criteria for Filing (Check all that apply)
See Instructions For More Information

EMERGENCY ALERT **File within 1-Hour** If any box 1-8 on the right is checked, this form must be filed within 1 hour of the incident; check Emergency Alert (for the Alert Status) on **Line A** below.	1. [ ] Physical attack that causes major interruptions or impacts to critical infrastructure facilities or to operations 2. [ ] Cyber event that causes interruptions of electrical system operations 3. [ ] Complete operational failure or shut-down of the transmission and/or distribution electrical system 4. [ ] Electrical System Separation (Islanding) where part or parts of a power grid remain(s) operational in an otherwise blacked out area or within the partial failure of an integrated electrical system 5. [ ] Uncontrolled loss of 300 Megawatts or more of firm system loads for 15 minutes or more from a single incident 6. [ ] Firm load shedding of 100 Megawatts or more implemented under emergency operational policy 7. [ ] System-wide voltage reductions of 3 percent or more 8. [ ] Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the electric power system
NORMAL REPORT **File within 6-Hours** If any box 9-12 on the right is checked AND none of the boxes 1-8 are checked, this form must be filed within 6 hours of the incident; check Normal Alert (for the Alert Status) on **Line A** below.	9. [ ] Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems 10. [ ] Cyber event that could potentially impact electric power system adequacy or reliability 11. [ ] Loss of electric service to more than 50,000 customers for 1 hour or more 12. [ ] Fuel supply emergencies that could impact electric power system adequacy or reliability

DRAFT

This is draft copy of DOE form OE-417 for recertification as of July 23, 2017.
This version of the form has not been approved for use by OMB.

SCHEDULE 1 -- ALERT CRITERIA -- CONTINUED

SYSTEM REPORT
File within 1-Business Day

If any box 13-24 on the right is checked AND none of the boxes 1-12 are checked, this form must be filed by the later of 24 hours after the recognition of the incident OR by the end of the next business day. *Note:* 4:00pm local time will be considered the end of the business day. Check System Alert (for the Alert Status) on **Line A** below.

13. [ ] 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 Bulk Electric System Emergency.

14. [ ] Damage or destruction of its Facility that results from actual or suspected intentional human action.

15. [ ] 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 its Facility.

16. [ ] Physical threat to its Bulk Electric System 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 its Bulk Electric System control center.

17. [ ] Bulk Electric System Emergency resulting in voltage deviation on a Facility; A voltage deviation of equal to or greater than 10% of nominal voltage sustained for greater than or equal to 15 continuous minutes.

18. [ ] Uncontrolled loss of 200 Megawatts or more of firm system loads for 15 minutes or more from a single incident for entities with previous year's peak demand less than or equal to 3,000 Megawatts

19. [ ] Total generation loss, within one minute of: greater than or equal to 2,000 Megawatts in the Eastern or Western Interconnection or greater than or equal to 1,400 Megawatts in the ERCOT Interconnection.

20. [ ] Complete loss of off-site power (LOOP) affecting a nuclear generating station per the Nuclear Plant Interface Requirements.

21. [ ] Unexpected Transmission loss within its area, contrary to design, of three or more Bulk Electric System Facilities caused by a common disturbance (excluding successful automatic reclosing).

22. [ ] Unplanned evacuation from its Bulk Electric System control center facility for 30 continuous minutes or more.

23. [ ] Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability affecting its staffed Bulk Electric System control center for 30 continuous minutes or more.

24. [ ] Complete loss of monitoring or control capability at its staffed Bulk Electric System control center for 30 continuous minutes or more.

If significant changes have occurred after filing the initial report, re-file the form with the changes and check Update (for the Alert Status) on **Line A** below.

The form must be re-filed within 72 hours of the incident with the latest information and Final (Alert Status) checked on **Line A** below, unless updated

LINE NO.						
A.	Alert Status (check one)	Emergency Alert [ ] 1 Hour	Normal Report [ ] 6 Hours	System Report [ ] 1 Business Day	Update [ ] As required	Final [ ] 72 Hours
B.	Organization Name					
C.	Address of Principal Business Office					

DRAFT

U.S. Department of Energy Electricity Delivery and Energy Reliability Form OE-417	*ELECTRIC EMERGENCY INCIDENT AND DISTURBANCE REPORT*	OMB No. 1901-0288 Approval Expires: xx/xx/xxx Burden Per Response: 1.8 hours

SCHEDULE 1 -- ALERT NOTICE

INCIDENT AND DISTURBANCE DATA

D.	Geographic Area(s) Affected (County, State)			
E.	Date/Time Incident Began (mm-dd-yy/hh:mm) using 24-hour clock	____ - _____ - _____ / _____: _____ mo dd yy hh mm	[ ] Eastern [ ] Central [ ] Mountain [ ] Pacific [ ] Alaska [ ] Hawaii	
F.	Date/Time Incident Ended (mm-dd-yy/ hh:mm) using 24-hour clock	_____ - _____ - _____ / _____: _____ mo dd yy hh mm	[ ] Eastern [ ] Central [ ] Mountain [ ] Pacific [ ] Alaska [ ] Hawaii	
G.	Did the incident/disturbance originate in your system/area? (check one)	Yes [ ]	No [ ]	Unknown [ ]
H.	Estimate of Amount of Demand Involved (Peak Megawatts)		Zero [ ]	Unknown [ ]
I.	Estimate of Number of Customers Affected		Zero [ ]	Unknown [ ]

SCHEDULE 1 – TYPE OF EMERGENCY

Check all that apply

J. Cause	K. Impact	L. Action Taken
☐ Unknown ☐ Physical attack ☐ Threat of physical attack ☐ Vandalism ☐ Theft ☐ Suspicious activity ☐ Cyber event (information technology) ☐ Cyber event (operational technology) ☐ Fuel supply emergencies, interruption, or deficiency ☐ Generator loss or failure not due to fuel supply interruption or deficiency or transmission failure ☐ Transmission equipment failure (not including substation or switchyard) ☐ Failure at high voltage substation or switchyard ☐ Weather or natural disaster ☐ Operator action(s) ☐ Other ☐ Additional Information/Comments:	☐ None ☐ Control center loss, failure, or evacuation ☐ Loss or degradation of control center monitoring or communication systems ☐ Damage or destruction of a facility ☐ Electrical system separation (islanding) ☐ Complete operational failure or shutdown of the transmission and/or distribution system ☐ Major transmission system interruption (three or more BES elements) ☐ Major distribution system interruption ☐ Uncontrolled loss of 200 MW or more of firm system loads for 15 minutes or more ☐ Loss of electric service to more than 50,000 customers for 1 hour or more ☐ System-wide voltage reductions or 3 percent or more ☐ Voltage deviation on an individual facility of ≥10% for 15 minutes or more ☐ Inadequate electric resources to serve load ☐ Generating capacity loss of 1,400 MW or more ☐ Generating capacity loss of 2,000 MW or more ☐ Complete loss of off-site power to a nuclear generating station ☐ Other ☐ Additional Information/Comments:	☐ None ☐ Shed Firm Load: Load shedding of 100 MW or more implemented under emergency operational policy (manually or automatically via UFLS or remedial action scheme) ☐ Public appeal to reduce the use of electricity for the purpose of maintaining the continuity of the electric power system ☐ Implemented a warning, alert, or contingency plan ☐ Voltage reduction ☐ Shed Interruptible Load ☐ Repaired or restored ☐ Mitigation implemented ☐ Other ☐ Additional Information/Comments

DRAFT

U.S. Department of Energy Electricity Delivery and Energy Reliability Form OE-417	*ELECTRIC EMERGENCY INCIDENT AND DISTURBANCE REPORT*	OMB No. 1901-0288 Approval Expires: xx/xx/xxx Burden Per Response: 1.8 hours

SCHEDULE 2 -- NARRATIVE DESCRIPTION

Information on Schedule 2 will not be disclosed to the public to the extent that it satisfies the criteria for exemption under the Freedom of Information Act, e.g., exemptions for confidential commercial information and trade secrets, certain information that could endanger the physical safety of an individual, or information designated as Critical Energy Infrastructure Information.

NAME OF OFFICIAL THAT SHOULD BE CONTACTED FOR FOLLOW-UP OR ANY ADDITIONAL INFORMATION		
M.	Name	
N.	Title	
O.	Telephone Number	( )-( )-( )
P.	FAX Number	( )-( )-( )
Q.	E-mail Address	

Provide a description of the incident and actions taken to resolve it. Include as appropriate, the cause of the incident/disturbance, change in frequency, mitigation actions taken, equipment damaged, critical infrastructures interrupted, effects on other systems, and preliminary results from any investigations. Be sure to identify: the estimate restoration date, the name of any lost high voltage substations or switchyards, whether there was any electrical system separation (and if there were, what the islanding boundaries were), and the name of the generators and voltage lines that were lost (shown by capacity type and voltage size grouping). If necessary, copy and attach additional sheets. Equivalent documents, containing this information can be supplied to meet the requirement; this includes the NERC EOP-004 Disturbance Report. **Along with the filing of Schedule 2, a final (updated) Schedule 1 needs to be filed. Check the Final box on line 1 for Alert Status on Schedule 1 and submit this and the completed Schedule 2 no later than 72 hours after detection that a criterion was met.**

R. Narrative:

DRAFT

S. Estimated Restoration Date for all Affected Customers Who Can Receive Power	_____ - _____ - _____ mo dd yy
T. Name of Assets Impacted	

DOE Staff Report on Electricity Markets and Reliability and DOE NOPR - Grid Resiliency Pricing Rule

Guy V. Zito
NPCC RSC
October 11-12, 2017

Overview

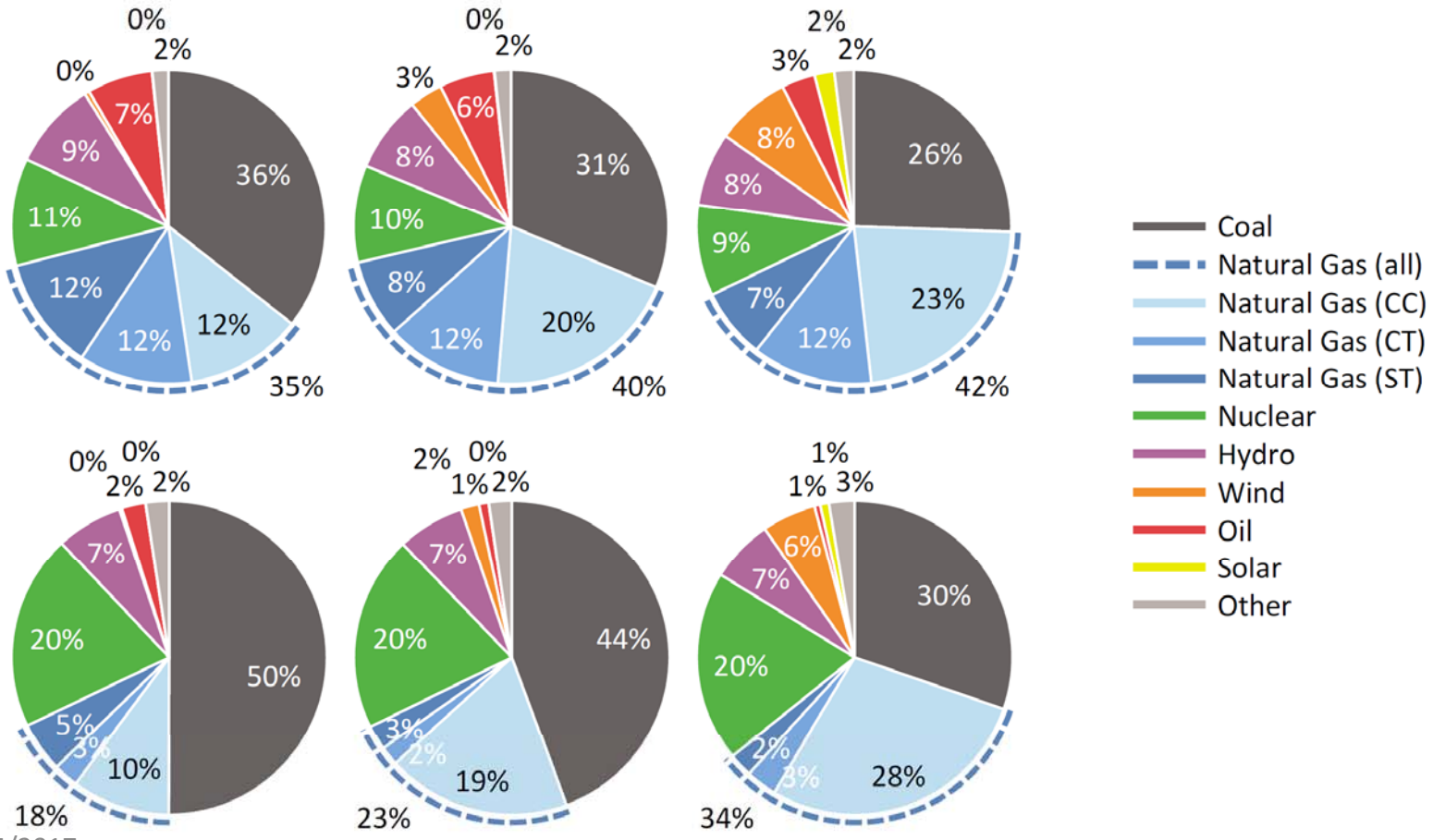
- **DOE Staff Report- What's in it**
- https://energy.gov/sites/prod/files/2017/08/f36/Staff%20Report%20on%20Electricity%20Markets%20and%20Reliability_0.pdf
- **DOE NOPR**
- https://www.energy.gov/sites/prod/files/2017/09/f37/Notice%20of%20Proposed%20Rulemaking%20.pdf
- **Timelines**
- **Future Actions**

DOE Staff Report- What's in it

- Published August 2017
- DOE study of electricity markets and impacts on reliability (Paraphrased)
  - Evolution of wholesale electricity markets, considering the changing electricity fuel mix – effect of markets;
  - Markets adequately compensating? Affect on grid reliability and resilience in the future; and
  - Are regulatory burdens, mandates, tax and subsidy policies, responsible for forcing the premature retirement of baseload power plants?

DOE Staff Report- What's in it

Figure 4.17. Changes in U.S. Capacity (Top) and Generation (Bottom) Mix over Time (Left to Right: 2002, 2009, 2016)[310]



DOE Staff Report- What's in it?

Power Plant Retirements

- Coal- 25% of operating electricity generating capacity in the United States and generated about 30% of U.S. electricity in 2016
- 2010–2015, coal plants 37 GW representing over 52 percent of recently retired power plant capacity
- 2016 and 2020, 34.4 GW of summer capacity is planned to be retired, and 79 percent of this planned retirement capacity are coal and natural gas plants (49 percent and 30 percent, respectively). The next largest set of planned retirements are nuclear plants (15 percent)
- 2002-2016, 531 Units 59,000 MW of capacity retired
- Causes-Mercury and Air Toxics Standards (MATS), Clean Water Act Section 316(b), Coal Combustion Residuals rule, also more competitive markets and a variety of regional and state-level policies involving renewables and carbon pricing

DOE Staff Report- What's in it?

Power Plant Retirements – cont.

- Natural Gas (NG)- 42% of operating electricity generating capacity in the United States and generated about 34% of U.S. electricity in 2016
- NG Combined Cycle (NGCC) units accounted for 54 percent of the 447,000 MW of total U.S. natural gas-powered generator capacity in 2016
- 2000–2010, Natural Gas plants- 33 GW were retired

DOE Staff Report- What's in it?

Power Plant Retirements – cont.

- Nuclear 54,000 MW of generating capacity in regulated markets and approximately 45,000 MW in restructured electricity markets- 60 Plants-99 reactors-90% Capacity Factor
- 2002-2016, 4,666 MW of nuclear generating capacity was announced for retirement, or approximately 4.7 percent of the U.S. total
- 2016-Current-7,167 MW of nuclear capacity (7.2 percent of U.S. nuclear capacity and 0.6 percent of total U.S. generating capacity have announced retirement plans

DOE Staff Report- What's in it?

Power Plant Retirements – cont.

- Hydroelectric-2,198 active power generation plants with a total capacity of 79,600 MW and 42 pumped-storage hydropower plants totaling 21,600 MW
- In 2016, hydropower accounted for more than six percent of net U.S. power sector electricity generation, nearly nine percent of U.S. electric generating capacity, and 97 percent of U.S. utility-scale electrical storage capacity
- Hydro-largest source of renewable generation, providing nearly 44 percent of all U.S. renewable energy in 2016
- 1,376 MW (of the total 79,985 MW of U.S. hydroelectric capacity) retired between 2002 and 2017—in most cases as part of repowering projects in which the retired turbine generators were replaced with new equipment

DOE Staff Report- What's in it?

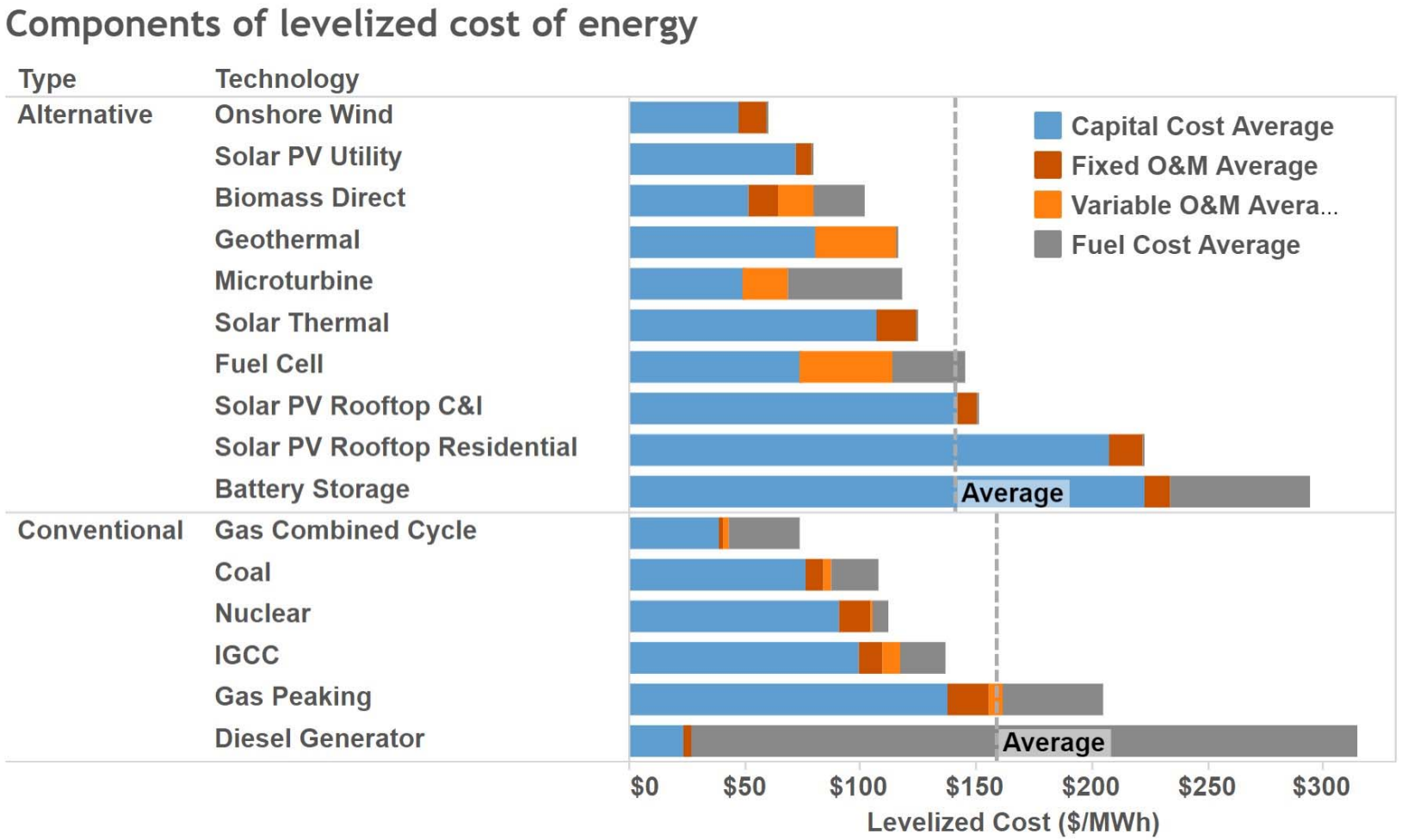
Variable Energy Resource (VRE) Penetration

- Wind surpassed 1 percent of total U.S. generation in 2008
- 2008-2013 wind increased to 4.5 percent of total US Generation end use demand, over 60,000 MW
- Solar generation reached the 1 percent of total generation in 2015
- Total renewable generation has now exceeded 14 percent of the U.S. total, with hydro and wind comprising the largest components
- Deployment grows due to lower costs, technology improvement, private sector sustainability goals, consumer choice, Federal and state incentives/subsidies which distort markets

DOE Staff Report- What's in it?

- Subsidies
  - American Recovery and Reinvestment Act of 2009, which allowed one-time cash grants to eligible renewable generators in lieu of tax credits-available to generators who began construction in 2009–2011
  - 2013 EIA Data-VRE technologies received a majority of Federal support that year relative to other technologies
    - 37% Wind
    - 27% Solar
    - Conventional Generation 20% (Coal, NG, and Nuclear)

Energy Costs-VRE vs. Conventional (not in Report)



DOE Staff Report- What's in it?

- Reliability and Resilience-Staff findings
  - Diverse portfolio and well planned Trans. investments to ensure Essential Reliability Svcs. (ERS), fuel assurance, and flexibility
  - Managing effects of VRE- long term forcasting, variability, location, low capacity factor, etc.
  - A more reliable and resilient system requires infrastructure hardening, and grid recovery and restoration strategies which require advanced planning and investment. Not a "least cost" system.

DOE Staff Report- What's in it?

- Importance of ERS
  - Frequency Control- Primary, Secondary and Tertiary
  - Ramping
  - Reserve
    - Frequency Responsive
    - Non-spinning
    - Operating
    - Regulating
    - Replacement
    - Spinning

DOE Staff Report- What's in it?

Fuel Diversity, Assurance and On-site Storage

- The grid was, on average, more diverse in 2016 than in 2002 in terms of both capacity and generation.
- Fuel Diversity is not a proxy for risk management and maintaining reliability
- Mandates and subsidies for renewables—skew investment risk and can undermine incentives for reliability-enhancing behavior
- Policies or market-design changes intended to increase fuel diversity will not necessarily improve risk management or reliability

DOE Staff Report- What's in it?

Fuel Diversity, Assurance and On-site Storage-cont.

- Natural gas "Single Point of Disruption"-planning, operational coordination, regulatory partnerships
- Natural Gas "just in time" delivery, pipeline constraints (increase NG storage? 400 facilities)
- Nuclear-18-24 months onsite storage
- Coal 85-100 day storage on average-rail and barge
  - Delivery interruptions-2013, there were 166 power plants (172,000 MW of generating capacity) across the United States that used subbituminous coal from the Powder River Basin.
  - 2013–2014, BNSF Railway rationed and limited coal deliveries to many of these generators due to construction and other disruptions. Stockpiles fell from 25 percent to 40 percent below normal levels at coal plants across the Midwest, Central, and Texas regions

DOE Staff Report- What's in it?

Fuel Diversity, Assurance and On-site Storage- cont.

- High Risk-Extreme Weather
  - NG curtailed due to interruptable contracts and high demand
  - Extreme cold freezes NG fuel injectors, compressors
  - Coal- Piles and conveyors freeze
  - Superstorm Sandy- flooding and destruction of ground and rooftop solar and wind generation due to lighting and high winds
  - Address with a broader range of study base cases, plausible market conditions, system contingencies, and public policy environments

DOE Staff Report- What's in it?

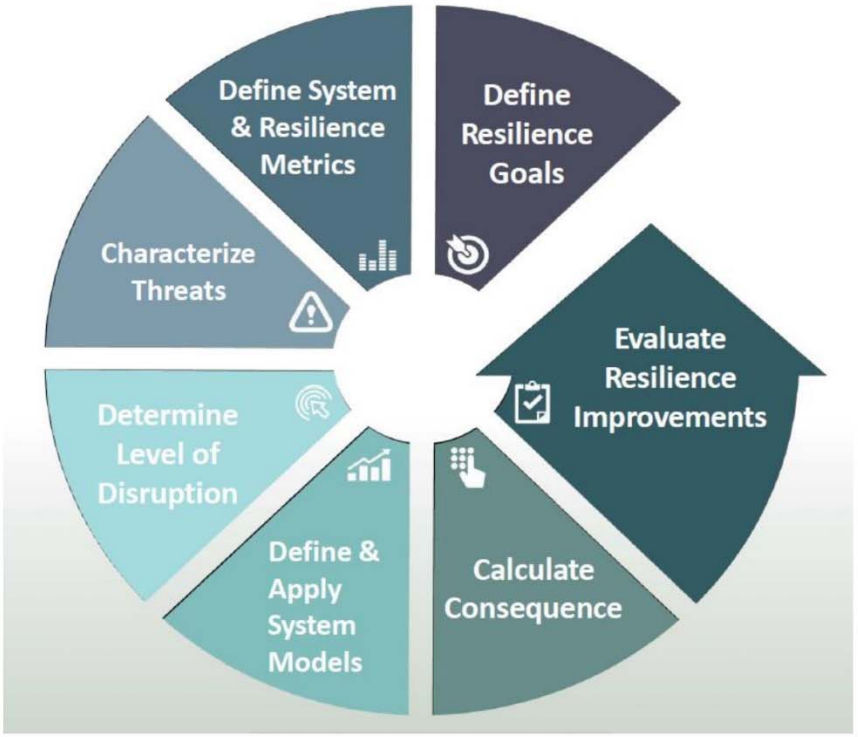
Wholesale Electricity Markets

DOE Staff Findings

- Challenges with centrally-organized wholesale markets. Flat demand growth, Federal and state policy interventions, economics of natural gas. Short term reliable operational success however potential long-term problems with bilateral markets.
- Low marginal cost VRE, reduce wholesale prices, independent of low natural gas prices further driven by subsidies and mandates, places undue economic pressure on revenues for traditional baseload (as well as non-baseload) resources and could require changes in market design
- Markets need further work to address grid resilience. Market mechanisms are designed to incentivize individual resources rather than develop balanced portfolios

Potential future actions for standards?

Figure 4.21. Sandia National Laboratories' Resilience Analysis Process[352]



Review Standards to consider:

- Planning-TPL and MOD-modeling standards
- Generator Performance- Governor response, Turbine Controls, AGC
- ERS-Frequency, Ramping and Reserves
- Resiliency standards

DOE Staff Report- What's in it?

8 Report Policy Recommendations (paraphrased):

- Wholesale markets: FERC to improve energy price formation in centrally-organized wholesale electricity markets. Negative offers should be mitigated to the broadest extent possible. Low marginal cost VRE, reduce wholesale prices, independent of low natural gas prices further driven by subsidies and mandates, places undue economic pressure on revenues for traditional baseload (as well as non-baseload) resources and could require changes in market design
- Valuation of Essential Reliability Services (ERS): FERC should study and make recommendations regarding efforts to require valuation of new and existing ERS-create fuel-neutral markets and/or regulatory mechanisms that compensate grid participants for services that are necessary to support reliable grid operations. Pricing mechanisms or regulations should be fuel and technology neutral and centered on the reliability services provided. DOE should provide technical and policy support that strengthen and accelerate these efforts.
- Bulk Power System (BPS) resilience: Transmission planning entities should conduct periodic disaster preparedness exercises involving electric utilities, regional offices of Federal agencies, and state agencies. **NERC should consider adding resilience components to its mission statement and develop a program to work with its member utilities to broaden their use of emerging ways to better incorporate resilience.** RTOs and ISOs should further define criteria for resilience, identify how to include resilience in business practices, and examine resilience-related impacts of their resource mix.

DOE Staff Report- What's in it?

Policy Recommendations (paraphrased):

- Promote Research and Development (R&D) of next-generation/21st century grid reliability and resilience tools: DOE should focus R&D efforts to enhance utility, grid operator, and consumer efforts to enhance system reliability and resilience.
- Support Federal and regional approaches to electricity workforce development and transition assistance: In partnership with other agencies and the private sector, DOE should facilitate programs and regional approaches for electricity sector workforce development.
- Energy dominance: Executive Order 13783 (Promoting Energy Independence and Economic Growth) outlined an approach to promote the clean and safe development of energy resources while at the same time minimizing regulatory barriers to energy production, economic growth, and job creation.

DOE Staff Report- What's in it?

Policy Recommendations (paraphrased):

- Infrastructure development: DOE and related Federal agencies should accelerate and reduce costs for the licensing, relicensing, and permitting of grid infrastructure such as nuclear, hydro, coal, advanced generation technologies, and transmission. DOE should review regulatory burdens for siting and permitting for generation and gas and electricity transmission infrastructure and should take actions to accelerate the process and reduce costs.
- Electric-gas coordination: Utilities, states, FERC, and DOE should support increased coordination between the electric and natural gas industries to address potential reliability and resilience concerns associated with organizational and infrastructure differences. DOE and FERC should support well functioning commodity markets for natural gas by expeditiously processing liquefied natural gas export and cross-border natural gas pipeline applications.

DOE NOPR

- DOE issued NOPR September 28th, 2017 in response to DOE Staff Report proposing a final rule for final action by FERC
- Discussions points of the NOPR
  - Affordable, Reliable and Resilient Electricity is Vital to the Economic and National Security of the United States and its People
  - There Have Been Significant Retirements of Fuel-Secure Generation
  - The 2014 Polar Vortex Exposed Problems With the Resiliency of the Electric Grid
  - Regulated Wholesale Power Markets Are Not Adequately Pricing Resiliency Attributes of Fuel-Secure Power
  - The Preservation of Generation Diversity Will Benefit Consumers
  - NERC Warns That Premature Retirements of Fuel-Secure Generation Threaten the Reliability and Resiliency of the Bulk Power System
  - The DOE Staff Report Made Clear the Challenges to the Grid and That Resiliency Must Be Addressed
  - Congress is Concerned About the Potential Loss of Valuable Generation Resources
  - The FERC is Cognizant of the Problem and Has the Necessary Information On Which to Act Expeditiously

DOE NOPR

Proposal

".. the Secretary is directing the Commission to issue a final rule requiring its organized markets to develop and implement market rules that accurately price generation resources necessary to maintain the reliability and resiliency of our Nation's bulk power system."

- Recovery of costs of fuel-secure generation relied upon to make our grid reliable and resilient
- Full recovery of costs of certain eligible units physically located within the Commission approved organized markets able to provide essential energy and ancillary reliability services and have a 90-day fuel supply on site in the event of supply disruptions caused by emergencies, extreme weather, or natural or man-made disasters.
- The rule requires the organized markets to establish just and reasonable rate tariffs for the recovery of costs and a fair rate of return.

DOE NOPR

Proposal cont.

- The final rule must require "..each Commission-approved RTO and ISO shall submit a compliance filing, including a revised tariff pursuant to section 205 of the Federal Power Act, within 15 days of the effective date of the final rule to demonstrate that it meets the proposed requirements set forth in any Final Rule."

Or

- To the extent that any RTO or ISO believes that it already complies with the reforms proposed in this NOPR, the RTO or ISO would be required to demonstrate how it complies in the compliance filing required 15 days after the effective date of any Final Rule

DOE NOPR

Timeframe:

- FERC issued a Notice Inviting Comments on October 2, 2017 for the DOE Proposal
- Comments due to the FERC on or before October 23, 2017
- The DOE Secretary is directing the Commission to take final action within 60 days of publishing the Notice in the Federal Register or issue the proposed rule as an interim rule.

FERC Order 837 RAS

- **Future Actions**
  - RSC to continue to discuss and engage on any standards related issues

- **Questions/Comments**

The Secretary of Energy
Washington, DC 20585

September 28, 2017

Neil Chatterjee, Chairman
Cheryl A. LaFleur, Commissioner
Robert F. Powelson, Commissioner
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: *Secretary of Energy's Direction that the Federal Energy Regulatory Commission Issue Grid Resiliency Rules Pursuant to the Secretary's Authority Under Section 403 of the Department of Energy Organization Act*

Dear Mr. Chairman and Commissioners:

America's greatness depends on a reliable, resilient electric grid powered by an "all of the above" mix of generation resources. This diverse mix of resources must include traditional baseload generation with on-site fuel storage that can withstand major fuel supply disruptions caused by natural and man-made disasters. But the resiliency of the electric grid is threatened by the premature retirements of these fuel-secure traditional baseload resources.

As the agency responsible for regulation of the organized power markets operated by the Commission-approved regional transmission organizations (RTOs) and independent system operators (ISOs), it is time for the Federal Energy Regulatory Commission ("Commission" or "FERC") to issue rules to protect the American people from the threat of energy outages that could result from the loss of traditional baseload capacity. In the wake of the devastation wrought by the Polar Vortex, Superstorm Sandy, and Hurricanes Harvey, Irma, and Maria, much more work needs to be done to preserve these fuel-secure generation resources that have the essential reliability and resiliency attributes needed to keep the lights on for all Americans in times of crisis—including on-site fuel supplies and the ability to provide voltage support, frequency services, operating reserves, and reactive power. As a first step, it is especially urgent to prevent premature retirements of the resources that have these critical attributes.

To this end, pursuant to section 403 of the Department of Energy Organization Act, I am making the enclosed rulemaking proposal for consideration and final action by the Commission pursuant to its authority under sections 205 and 206 of the Federal Power Act. Distorted price signals in the Commission-approved organized markets have resulted in under-valuation of grid reliability and resiliency benefits provided by traditional baseload resources, such as coal and nuclear. The rule will ensure that each eligible reliability and resiliency resource will recover its fully allocated costs and thereby continue to provide the energy security on which our nation relies. The Commission is required to take final action on this proposal in an expeditious manner in accordance with the reasonable time limits specified in the enclosed Notice of Proposed Rulemaking (NOPR).

The Resiliency of the Electric Grid—and Our National Security—is In Jeopardy

Ensuring that American families and their businesses have access to reliable, resilient and affordable electricity is vital to the economy, national security and quality of life. From heating homes in the winter to cooling them in the summer, providing lighted streets so people can walk safely at night, powering machines and technology that create jobs, and connecting us through smart phones and the internet—electricity is a key driver of America's economic prosperity and the basic necessities of life. Our economy, government and national defense all depend on electricity. Therefore, ensuring a reliable and resilient electric supply and corresponding supply chain are vital to national security.

There Have Been Significant Retirements of Traditional Baseload Generation

Market changes are resulting in a significant loss of traditional baseload generation. According to the Department of Energy's January 2017 *Quadrennial Energy Review* (January 2017 QER):

> Currently, the changing electricity sector is causing the closure of many coal and nuclear plants in a shift from recent trends. From 2000 through 2009, power plant retirements were dominated by natural gas steam turbines. Over the past 6 years (2010–2015), power plant retirements were dominated by coal plants (37 GW), which accounted for over 52 percent of recently retired power plant capacity. Over the next 5 years (between 2016 and 2020), 34.4 GW of summer capacity is planned to be retired, and 79 percent of this planned retirement capacity are coal and natural gas plants (49 percent and 30 percent, respectively). The next largest set of planned retirements are nuclear plants (15 percent).[1]

The Department of Energy's *Staff Report to the Secretary on Electricity Markets and Reliability* (DOE Staff Report)[2] also discusses the large number of traditional baseload units that have retired or are scheduled to retire:

- Between 2002 and 2016, 531 coal generating units representing approximately 59,000 MW of generation capacity retired from the U.S. generation fleet.[3]
- EIA reported that coal-fired power plants made up more than 80 percent of the 18,000 MW of electric generating capacity that retired in 2015.[4]
- It is anticipated that approximately 12,700 MW of coal will retire through 2020.[5]

---

[1] *Transforming the Nation's Electricity System: the Second Installment of the Quadrennial Energy Review*, January 6, 2017 (2017 QER), at 3-73.

[2] U.S. Department of Energy, *Staff Report to the Secretary on Electricity Markets and Reliability*, August 2017 (DOE *Staff Report*).

[3] DOE *Staff Report* at 22.

[4] DOE *Staff Report* at 22, citing U.S. Energy Information Administration, *Today in Energy*, March 8, 2016. More recent EIA data shows an overall larger amount of 2015 generation capacity retirements (25,400 MW), of which coal-fired power plants made up 72%. EIA, *Monthly Update to the Annual Electric Generator Report*, Form EIA-860m, March 2017.

[5] U.S. Energy Information Administration (EIA), *Monthly Update to the Annual Electric Generator Report*, Form EIA-860m, June 2017, https://www.eia.gov/electricity/data/eia860m/.

- Between 2002 and 2016, 4,666 MW of nuclear generating capacity was announced for retirement, or approximately 4.7 percent of the U.S. total.[6]
- Eight reactors representing 7,167 MW of nuclear capacity (7.2 percent of U.S. nuclear capacity and 0.6 percent of total U.S. generating capacity) have announced retirement plans since 2016. This does not include seven reactors that averted early retirement through state action.[7]

The 2014 Polar Vortex Exposed Problems With the Resiliency of the Electric Grid

In early 2014, the Polar Vortex (a band of very cold weather spread across much of the eastern United States) created record-high winter peak electric demand for heating and equally high demand for natural gas for residential heating. During the Polar Vortex, PJM Interconnection ("PJM")[8] struggled to meet demand for electricity because a significant amount of generation was not available to run. The loss of generation capacity could have been catastrophic, but a number of coal plants that were scheduled for retirement were dispatched to meet the need for electricity:

> American Electric Power reported that it deployed 89 percent of its coal units scheduled for retirement in 2014 to meet demand during the Polar Vortex, and Southern Company reported using 75 percent of its coal units scheduled for closure. Using these retiring units enabled utilities to meet customer demand during a period when already limited natural gas resources were diverted from electricity production to meet residential heating needs. Once retired, however, these units will not be available for the next unseasonably cold winter.[9]

Likewise, nuclear power plants "performed extremely well during the Polar Vortex, with an average capacity factor of 95 percent."[10]

Sixty-five million people within the PJM footprint could have been affected if these traditional baseload units were not available. The 2014 Polar Vortex was a warning that the current and scheduled retirements of these fuel-secure units could threaten the reliability and resiliency of the electric grid.[11]

Regulated Wholesale Power Markets Are Not Adequately Pricing Resiliency Attributes of Baseload Power

There is a growing recognition that Commission-approved organized markets do not necessarily pay generators for all the attributes that they provide to the grid, including resiliency. Because wholesale pricing in those markets does not adequately consider or accurately value those benefits, generation units that provide the benefits are often not fully compensated for them.

---

[6] DOE *Staff Report* at 29.
[7] DOE *Staff Report* at 30.
[8] PJM Interconnection is the regional transmission organization ("RTO") serving thirteen states and the District of Columbia.
[9] DOE *Staff Report* at 98 (internal citations omitted).
[10] DOE *Staff Report* at 95 (internal citations omitted).
[11] DOE *Staff Report* at 98-99, 118.

The January 2017 QER summarizes the problem of how Commission-approved wholesale markets are not adequately pricing resiliency attributes of traditional baseload generation:

> Reliability investments are typically incorporated into ratemaking processes for all electric utilities. Supplementary investments for recovery from outage events also are handled through established ratemaking processes. Resilience requirements tend to be valued as contributions to reliability and incorporated as part of ratemaking processes. These processes are more easily executed in structures that are traditional end-to-end, vertically integrated electricity delivery services; other market structures complicate reliability and resilience investment decision-making. Short-run markets may not provide adequate price signals to ensure long-term investments in appropriately configured capacity. Also, resource valuations tend not to incorporate superordinate network and/or social values such as enhancing resilience into resource or . . . investment decision making. The increased importance of system resilience to overall grid reliability may require adjustments to market mechanisms that enable better valuation.[12]

A recent study by IHS Markit amplifies the same point: "the increasing cost of ensuring power system resilience is exposing the problem that some current wholesale market price formation rules do not fully compensate generating resources for providing the desired power system supply resiliency."[13]

Yet adequately compensating generating resources for ensuring a resilient grid and our national security does not mean that the costs of maintaining our grid will necessarily increase. In fact, as the IHS Markit study also concludes, preservation of traditional baseload resources benefits consumers: "The current diversified US electric supply portfolio lowers the cost of electricity production by about $114 billion per year and lowers the average retail price of electricity by 27%" compared with a "less efficient diversity case" involving "no meaningful contributions from coal or nuclear resources."[14] Thus, this rule will ensure both a resilient grid and affordable electricity to drive economic prosperity.

NERC Warns That Premature Retirements Of Fuel-Secure Generation Threaten the Reliability and Resiliency of the Bulk Power System

The North American Electric Reliability Corporation (NERC) (the FERC-designated Electric Reliability Organization), whose mission is to assure the reliability and security of the bulk power system in North America, states:

> The North American electric power system is undergoing a rapid and significant transformation with ongoing retirements of fossil-fired and nuclear capacity, as

---

[12] 2017 *QER*, at 4-41 (emphasis added).
[13] IHS Markit, *Ensuring Resilient and Efficient Electricity Generation: The Value of the Current Diverse US power Supply Portfolio*, at 8.
[14] Id. at 4-5.

> well as growth in natural gas, wind, and solar resources. This shift is caused by several drivers, such as federal, state, and provincial policies, low natural gas prices, electricity market forces, and integration of both distributed and utility-scale renewable resources. The changing resource mix is altering the operating characteristics of the bulk power system (BPS). These changing characteristics must be well understood and properly managed in order to assure continued reliability and ensure resiliency.[15]

Specifically, NERC explains, "Coal-fired and nuclear generation have the added benefits of high availability rate, low forced outages, and secured on-site fuel. Many months of on-site fuel allow these units to operate in a manner independent of supply chain disruptions."[16]

As a consequence, NERC warns, "Premature retirements of fuel secure baseload generating stations reduces resilience to fuel supply disruptions."[17]

The DOE Staff Report Made Clear the Challenges to the Grid and That Resiliency Must Be Addressed

The DOE Staff Report confirms these observations and exposes the potential challenges and threats to the reliability and resiliency of the electric grid, as well as the economic hardship faced by some of the most resilient types of generation. Among other things, the DOE Staff Report warns that premature retirements of fuel-secure resources impose serious risks:

> Ultimately, the continued closure of traditional baseload power plants calls for a comprehensive strategy for long-term reliability and resilience. States and regions are accepting *increased risks* that could affect the future reliability and resilience of electricity delivery for consumers in their regions. Hydropower, nuclear, coal, and natural gas power plants provide ERS ["essential reliability services"] and fuel assurance critical to system resilience. A continual comprehensive regional and national review is needed to determine how a portfolio of domestic energy resources can be developed to ensure grid reliability and resilience.[18]

The DOE Staff Report also recognizes that "system fuel supply chain disruptions can impact many generators during a single widespread fuel shortage event," and that "[n]uclear and coal plants typically have advantages associated with onsite fuel storage...."[19] In light of these facts, the DOE Staff Report calls for prompt action:

> Markets need further study and reform to address future services essential to grid reliability and resilience. System operators are working toward recognizing,

---

[15] NERC Letter to Secretary of Energy Rick Perry, May 9, 2017, Attachment "Synopsis of NERC Reliability Assessments" (Synopsis) at 1 (emphasis added).
[16] NERC, Synopsis at 2.
[17] NERC, Synopsis at 3.
[18] DOE *Staff Report* at 14 (emphasis added).
[19] DOE *Staff Report*, at 91. For example, "coal plants . . . maintain onsite coal stockpiles to accommodate both normal variance in deliveries and the possibility of a major supply disruption. Coal stockpiles have recently been slightly smaller than historical averages, while days of burn have increased slightly relative to historic averages from the 70-80 range to the 85-100-day range." *Id.*, at 95.

> defining, and compensating for resource attributes that enhance reliability and resilience (on both the supply and demand side). However, further efforts should reflect the *urgent* need for clear definitions of reliability- and resilience-enhancing attributes and should *quickly establish* the market means to value or the regulatory means to provide them.[20]

One of the DOE Staff Report's chief policy recommendations to protect the resiliency of the electric grid is to correct distortions in price formation in the organized markets:

> FERC should expedite its efforts with states, RTO/ISOs, and other stakeholders to improve energy price formation in centrally-organized wholesale electricity markets. After several years of fact finding and technical conferences, the record now supports energy price formation reform, such as the proposals laid out by PJM and others.[21]

FERC is Aware Of the Problem and Must Take Action

As is well known, over the past several years, the Commission has developed an extensive record on price formation in the Commission-approved ISOs and RTOs. The Commission has recognized that there are deficiencies in the way the regulated wholesale power markets price power (i.e., energy, capacity, and ancillary services) and that these deficiencies are undermining reliability and resiliency.

Beginning in 2013, the Commission recognized the changing mix of generation resources, determined that the existing capacity markets were not providing a sufficiently reliable supply of electricity, predicted the loss of traditional baseload generation, and sought input from the public through proceedings on price formation in the organized markets. In a 2013 technical conference, FERC explained:

> The purpose of the technical conference is to consider how current centralized capacity market rules and structures are supporting the procurement and retention of resources necessary to meet future reliability and operational needs. Since their establishment, centralized capacity markets have continued to evolve. Meanwhile, the mix of resources is also evolving in response to changing market conditions, including low natural gas prices, state and federal policies encouraging the entry of renewable resources and other specific technologies, and the retirement of aging generation resources. This changing resource mix may result in future reliability and operational needs that are different than those of the past.[22]

Nevertheless, the fundamental challenge of maintaining a resilient electric grid has not been sufficiently addressed by the Commission or the Commission-approved ISOs and RTOs, and the lack of a quorum at the Commission has undoubtedly thwarted the issuance of rules. But the continued loss of baseload generation with on-site fuel supplies, such as coal and nuclear,

---

[20] *Id.*, at 10 (emphasis added).
[21] *Id.*, at 126 (internal citations omitted).
[22] FERC, *Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators*, Docket No. AD13-7-000, at 1.

must be stopped. These generation resources are necessary to maintain the resiliency of the electric grid. As FERC already regulates the organized wholesale power markets, it must adopt rules requiring the Commission-approved ISOs and RTOs to reduce the chronic distortion of those markets threatening the resilience of the nation's electricity system.

In light of these threats to grid reliability and resilience, it is the Commission's immediate responsibility to take action to ensure that the reliability and resiliency attributes of generation with on-site fuel supplies are fully valued and in particular to exercise its authority to develop new market rules that will achieve this urgent objective.

Failure to act expeditiously would be unjust, unreasonable, and contrary to the public interest.

Proposed Rule To Protect the Resiliency Of the Electric Grid

Therefore, pursuant to my authority under section 403 of the Department of Energy Organization Act to propose rules for adoption by the Commission, I am proposing the enclosed rule, which will be published in the Federal Register.

The proposed rule requires the Commission-approved organized markets to develop and implement market rules that accurately price generation resources necessary to maintain the reliability and resiliency of our Nation's electric grid. Specifically, the rule allows for the recovery of costs of fuel-secure generation units that make our grid reliable and resilient. Such resources provide reliable capacity, resilient generation, frequency and voltage support, on-site fuel inventory—in addition to providing power for our basic needs, quality of life, and robust economy. The rule allows the full recovery of costs of certain eligible units physically located within the Commission-approved organized markets. Eligible units must also be able to provide essential energy and ancillary reliability services and have a 90-day fuel supply on site in the event of supply disruptions caused by emergencies, extreme weather, or natural or man-made disasters. These resources must be compliant with all applicable environmental regulations and are not subject to cost-of-service rate regulation by any State or local authority. The rule requires the organized markets to establish just and reasonable rate tariffs for the full recovery of costs and a fair rate of return.

Now that a quorum has been restored at the Commission, I am confident that the Commission will act in an expeditious manner to address this urgent issue. To that end, in the enclosed NOPR, I direct the Commission to consider and complete final action on the rule proposed therein within 60 days from the date of the publication of the NOPR in the Federal Register. As an alternative, I urge the Commission to issue the proposed rule as an interim final rule, effective immediately, with provision for later modifications after consideration of public comments. Further, I am directing that any final rule adopting this proposal take effect within 30 days of publication of such final rule in the Federal Register, and I am proposing that each Commission-approved RTO and ISO submit a compliance filing within 15 days of the effective date of the rule.

Conclusion

It is the policy of this Administration to support an "all of the above" approach to energy development and use. We need to properly recognize the value of each resource, being mindful of its role in our national defense, economic security, and pursuit of environmental outcomes. In particular, we must account for the value of on-site fuel storage capability. Moreover, because of the long lead time to secure and maintain these resources, we must also ensure that the technical expertise and materials are readily available. If, for example, we lose our educated workforce or no longer have the ability to build and operate our baseload plants because of short-sighted policies, it will not only weaken our workforce, but will threaten our energy dominance and national security.

On behalf of the American people, I look forward to your immediate action on the pressing issue of protecting the resiliency of the electric grid.

Sincerely,

Rick Perry

Rick Perry

Friday, September 29, 2017 12:50 PM ET Extra

DOE proposal asking FERC to bolster coal, nuclear generation scant on details

By Glen Boshart

In a highly unusual move, the U.S. Department of Energy has issued a rough proposal directing the Federal Energy Regulatory Commission to adopt a new rule requiring operators of organized markets to "ensure that certain reliability and resiliency attributes of electric generation resources are fully valued."

Moreover, the DOE is demanding that FERC act on the rule within just 60 days, or alternatively issue an interim rule immediately "with provision for later modifications after consideration of public comments." The DOE also is insisting that regional transmission organizations and independent system operators submit compliance filings within 15 days of the effective date of a final rule.

FERC's issuance of an important new final rule within 60 days would be unprecedented. But the DOE said "by proposing a rule in this manner, the secretary enables the commission to proceed directly to the consideration of, and final action on, the proposal and eliminates the need for the commission to order or publish its own separate rulemaking proposal."

The DOE's proposal also is surprising given that an anxiously awaited study released in August by that agency concluded that the reliability of the power grid is under no immediate threat from the retirement of what has traditionally been considered baseload generating units, although it said further study was needed to evaluate long-term threats.

But the DOE in the proposed rule said it believes something needs to be done now and it is justified in using its authority under Section 403 of the Department of Energy Organization Act to propose rules for FERC action. The DOE also insisted that the proposed deadlines are reasonable given the extensive record FERC already has developed on the issue.

"The resiliency of the nation's electric grid is threatened by the premature retirements of power plants that can withstand major fuel supply disruptions caused by natural or man-made disasters and, in those critical times, continue to provide electric energy, capacity, and essential grid reliability services," the DOE said. "It is time for the commission to issue rules to protect the American people from energy outages expected to result from the loss of this fuel-secure generation capacity."

To drive its point home, the DOE cited the polar vortex that hit the PJM Interconnection region in early 2014 and the grid operator's need to call on a number of "fuel secure" power plants previously scheduled to retire to run when other generators went out of service.

The DOE also cited a "growing recognition" that unlike traditional vertically integrated market structures, organized markets do not necessarily pay generators for all the attributes they provide to the grid, including the resiliency attributes of fuel-secure generation — mainly coal-fired and nuclear power plants.

The proposed rule repeatedly referred to the findings of the DOE's grid reliability study, including that states and regions "are accepting increased risks" that could cause reliability problems in the future, and asserting that nuclear and coal-fired plants are more resilient because they have onsite fuel sources that are not threatened by extreme weather conditions. The DOE noted that Congress also has expressed similar concern about the premature retirements of "otherwise performing baseload units because of market rules."

While the DOE acknowledged all the steps FERC has taken since 2013 to examine price formation issues in organized markets, it nevertheless insisted that the commission still has not addressed the "fundamental challenge of maintaining a resilient electric grid."

"The continued loss of fuel-secure generation must be stopped," the DOE said. "FERC must adopt rules requiring ... ISOs and RTOs to reduce the chronic distortion of the markets that is threatening the resilience of the nation's electric system."

DOE said it therefore is "directing" FERC to issue a final rule requiring organized market operators to implement new market rules that allow generating units with at least a 90-day fuel supply on site and not subject to cost-of-service regulation to fully recover their costs.

The proposed DOE rule does not get into the specifics of how those rates are to be developed, simply stating that RTOs and ISOs must submit compliance filings proposing tariff changes or otherwise demonstrating that they already comply with the rule's requirements. (*FERC docket RM17-3*)

Staff Report to the Secretary on Electricity Markets and Reliability

August 2017

Table of Contents

Table of Contents .....

List of Figures .....

List of Tables .....

1 Introduction **1**

2 Findings of This Study **10**

3 Power Plant Retirements **15**

3.1 Coal Plant Retirements 20

3.2 Natural Gas Plant Retirements 24

3.3 Nuclear Plant Retirements 27

3.4 Hydropower Retirements and Repowering 34

3.5 Falling Natural Gas Prices 35

3.6 Environmental Regulations 39

3.7 Growing VRE Deployment 47

3.8 Flattening Electricity Demand 54

3.9 Power Plant Retirements Looking Forward 57

4 Reliability and Resilience **61**

4.1 Assessing Challenges to Reliability 63

4.2 Diversity, Fuel Assurance, and Onsite Storage 89

4.3 High-Risk Events and System Resilience 97

4.4 Enhancing Reliability and Resilience 99

4.5 Reliability and Resilience Looking Forward 100

5 Wholesale Electricity Markets **102**

5.1 Evolution of U.S. Wholesale Electricity Markets 102

5.2 Wholesale Electricity Markets Today 104

5.3 Challenges in Wholesale Electricity Markets 107

5.4 Wholesale Electricity Markets Looking Forward 118

6 Affordability **119**

6.1 Affordability of Generation Portfolios 119

6.2 The Wholesale-Retail Disconnect 120

6.3 Affordability Looking Forward 124

7 Policy Recommendations **126**

8 Areas for Further Research **128**

Appendix A: National and Regional Profiles **130**

Appendix B: VRE Integration Studies **151**

Appendix C: Power Plant Cycling **154**

List of Figures

Figure 1.1. Regions Used in This Study 4
Figure 1.2. Schematic of Typical Daily Load Curve Showing Base Load 6
Figure 3.1. Location of Coal, Natural Gas, Nuclear, and All Other Retirements, 2002–2016 15
Figure 3.2. Net Generation Capacity Additions and Retirements 16
Figure 3.3. Retirements of Coal, Natural Gas, Nuclear, and Other Generating Units, 2002–2022 18
Figure 3.4. Retirements by Date, Location, Ownership, and Capacity 18
Figure 3.5. Operating Generation Capacity, Additions, Retirements, and Announced Retirements by Region for All Generation Types, January 2002–December 2022 20
Figure 3.6. Location of the Existing Coal Fleet 21
Figure 3.7. Location of Coal Retirements, 2002–2016 21
Figure 3.8. U.S. Utility-Scale Coal-Fired Electric Generating Capacity Additions by Coal Type and Initial Operating Year 22
Figure 3.9. Location of the Existing Natural Gas Fleet 25
Figure 3.10. Capacity Additions of U.S. Utility-Scale Natural Gas-Fired Electricity Generation by Technology Type and Initial Operating Year 26
Figure 3.11. Natural Gas Fleet Capacity Factors 26
Figure 3.12. Location of Natural Gas Retirements 27
Figure 3.13. Location of the Existing Nuclear Fleet 28
Figure 3.14. Location of Nuclear Power Plant Retirements: Closed, Announced, and Averted 30
Figure 3.15. Nuclear Plant Retirements Compared to NRC Plant Operating License Terms 33
Figure 3.16. Hydropower Plants in the United States by Capacity and Average Annual Runoff 34
Figure 3.17. Conventional and Shale Natural Gas Production, 2007–2016 36
Figure 3.18. Wholesale Day-Ahead Electricity Prices vs. Henry Hub Natural Gas Price (Monthly Average) 37
Figure 3.19. Total Annual U.S. Natural Gas Generation, 1950–2016 38
Figure 3.20. Heat Rates for Coal, Nuclear, and Natural Gas, 2002–2016 39
Figure 3.21. PJM Merit-Order Dispatch: Various Control Technologies 42
Figure 3.22. Changes in U.S. Coal Capacity, December 2014–April 2016 44
Figure 3.23. Average Coal Plant Capacity Factors, 2008–2014 45
Figure 3.24. Projected and Actual Coal Retirements, 2008–2018 46

Figure 3.25. VRE Generation by Fuel as Percentage of Total U.S. Generation, 2002–2016 48

Figure 3.26. Cumulative U.S. Utility-Scale Wind and Hydroelectric Generation Capacity, 1915–December 2016 48

Figure 3.27. Relationship between the PTC and Annual Wind Capacity Additions 50

Figure 3.28. VRE Penetration as a Percentage of 2016 Generation versus Retired Capacity since 2010 as a Percentage of Non-VRE Capacity 51

Figure 3.29. Gross Domestic Product and Net Electricity Production, Historical (1950–2016) and Projected (2017–2027) 54

Figure 3.30. Estimated U.S. Energy Savings from Structural Changes in the Economy and Energy Efficiency, 1980–2016 55

Figure 3.31. EIA Annual Electricity Sales 2000–2016 (terawatt-hours) and AEO Reference Case Electricity Sales Projections 2017–2030 56

Figure 3.32. Baseload Capacity Additions and Retirements from EIA AEO 2017 (No Clean Power Plan Scenario) 57

Figure 3.33. Modeled Projections for Natural Gas Price, Electricity Sales, and VRE Generation from EIA AEO 2017 (No Clean Power Plan Scenario) 58

Figure 3.34. NGCC Capacity Factors and Number of Starts, 1998–2016 59

Figure 4.1. System Operation Time Scales 62

Figure 4.2. Five-Year Average Reserve Margins across Different Regions (2018–2022) 66

Figure 4.3. Historical Solar On-Peak Capacity Factors in ERCOT 67

Figure 4.4. NERC Definitions of Reserves Used to Provide ERS 70

Figure 4.5. System Frequency after a Grid Event (Top) and How Frequency Control Mechanisms Work to Restore Frequency (Bottom) 71

Figure 4.6. EEI Historical and Project Transmission Investment (Nominal Dollars) 76

Figure 4.7. Location of the Existing Wind Fleet 77

Figure 4.8 Wind Energy Share of Electric Generation by State, 2016 78

Figure 4.9. Ways To Integrate VRE, Arrayed by Type of Intervention and Cost (2014) 80

Figure 4.10. CAISO Load, Net Load, and Wind and Solar Output on Example Weekdays during 2014 82

Figure 4.11. The CAISO Duck Curve 83

Figure 4.12. Demand and Net Demand Shapes at Different Distributed Energy Resource Penetration Levels 84

Figure 4.13. Mapping Reliability Attributes Against Resources 86

Figure 4.14 Selected Ancillary Service Market Design Characteristics 87

Figure 4.15. Ancillary Service Products Exchanged in the Centrally Organized Markets, Listed by RTO/ISO and Category of Ancillary Service 88

Figure 4.16. Generation Mix and Various Economic and Policy Drivers Since 1949, Including Diversity Index 89

Figure 4.17. Changes in U.S. Capacity (Top) and Generation (Bottom) Mix over Time (Left to Right: 2002, 2009, 2016) 90
Figure 4.18. Natural Gas Storage Facilities 93
Figure 4.19. Coal Stocks and Days of Burn, January 2010–May 2017 96
Figure 4.20. Electricity Generation Changes from 2013 to 2014 by Fuel Type 97
Figure 4.21. Sandia National Laboratories' Resilience Analysis Process 101
Figure 5.1. Utility Restructuring by State as of May 2017 104
Figure 5.2. The Seven RTOs or ISOs in the United States 105
Figure 5.3. States and Regions along the Spectrum from Traditional to Fully Restructured Electric Markets 106
Figure 5.4. How Market Prices Allow Resource Costs to be Recovered in a Centrally-organized Wholesale Market 110
Figure 5.5. Simulated ERCOT Dispatch Curves 112
Figure 5.6. Type of Fuel Used in PJM (by Real-Time Marginal Units): 2004 through March 2017 113
Figure 5.7. Annual Average Capacity Factors of Coal and Natural Gas Generators 113
Figure 5.8. Negative Northwest Off-Peak Daily Spot Prices ($/MWh) in 2011 116
Figure 6.1. Average U.S. Residential Sector Retail Electricity Prices over Time 121
Figure 6.2. Average Wholesale Electric Costs/MWh Have Fallen between 2002 and 2016. 122
Figure 6.3. Day-Ahead, On-Peak Wholesale Electric Prices Reach Near-Record Lows in 2016. 123
Figure 8.1. Average Three-Year Capacity Factors for Retired U.S. Coal Plants 155

List of Tables

Table 3-1. Direct Employment and Income in Industries Related to Electric Power Supply, 2016 23
Table 3-2. Nuclear Plant Retirements, Announced Closures, and Plants Averted by State Action 31
Table 3-3. Average Nuclear Costs by Plant Size and Operator Type, 2016..... 32
Table 3-4. Major Environmental Regulations Related to Coal, Natural Gas, and Nuclear Generation 40
Table 3-5. Fiscal Year 2013 Electricity Production Subsidies and Support 53
Table 4-1. How Various Energy Storage Options Can Deliver Grid-Level Applications 74
Table 4-2. Characteristics of VRE, Grid Integration Challenges, and Mitigation Options..... 78
Table 4-3. Dependence on Imported Just-in-Time Energy for Electricity..... 94
Table B-1. VRE Integration Studies 151

1 Introduction

On April 14, 2017, Energy Secretary Rick Perry issued a memorandum requesting a study to examine electricity markets and reliability. With this document, Department of Energy (DOE) staff are delivering a study that seeks not only to evaluate the present status of the electricity system, but more importantly to exercise foresight to help ensure a system that is reliable, resilient, and affordable long into the future. Therefore, while carefully acknowledging history, this study focuses on the present trajectory of trends that are of particular concern in meeting those long-term goals.

Specifically, the April 14 memo directed a study that explores the following three issues:

- The evolution of wholesale electricity markets, including the extent to which Federal policy interventions and the changing nature of the electricity fuel mix are challenging the original policy assumptions that shaped the creation of those markets;
- Whether wholesale energy and capacity markets are adequately compensating attributes such as on-site fuel supply and other factors that strengthen grid resilience and, if not, the extent to which this could affect grid reliability and resilience in the future; and
- The extent to which continued regulatory burdens, as well as mandates and tax and subsidy policies, are responsible for forcing the premature retirement of baseload power plants.

The U.S. electricity industry is facing unprecedented changes. Last year, for the first time in history, natural gas replaced coal as the leading source of electricity generation. In 2015, a record-high amount of generating capacity retired. Over the course of the last decade, overall growth in electricity consumption at the national level has stalled, while many generation sources—particularly natural gas, wind, and solar—frequently hit new record levels of penetration.

The stakes are high around these issues because electricity is crucial to modern society and economic activity, and because of the physical and financial magnitude of the industry. As noted in the report, *Transforming the Nation's Electricity System: The Second Installment of The Quadrennial Energy Review* (QER 1.2):

> The United States has around 7,700 operating power plants[1] that generate electricity from a variety of primary energy sources; 707,000 miles of high-voltage transmission lines;[2] more than 1 million rooftop solar installations;[3] 55,800 substations;[4] 6.5 million miles of local distribution lines;[5] and 3,354 distribution utilities[6] delivering electricity to 148.6 million customers. The total amount of money paid by end users end for electricity in 2015 was about $400 billion.[7] This drives an $18.6 trillion U.S. gross domestic product and significantly influences global economic activity totaling roughly $80 trillion.[8]

Recognizing how vital electricity is to our society and the health of the U.S. economy, the April 14 memo asked staff to "provide concrete policy recommendations and solutions." It also offered principles for policy formulation: "the Trump Administration will be guided by the principles of reliability, resilience, affordability, and fuel diversity—principles that underpin a thriving economy." To that end, this report concludes by outlining policy recommendations to advance those principles.

Section 2 of this study offers a summary of findings. Sections 3 through 6 provide the analytical framework, relevant data, and research. In addition, each of these sections concludes with a "looking forward" note, as many of the issues raised in the April 14 memo are of growing importance. Section 1

presents policy recommendations available—to DOE and others—to address the issues identified in this study. Section 8 outlines potential areas for further research.

Data Used in This Study

This study uses data collected by the Energy Information Administration (EIA) for the years 2002 through 2017, looking back before 2002 on a few specific issues. The 2002–2017 time range captures several important developments:

- Centrally-organized wholesale electricity markets (Regional Transmission Operators [RTOs] and Independent System Operators [ISOs]) were in the early stages of implementation in 2002. Competition within centrally-organized markets among a large segment of merchant generation did not take effect until the mid-2000s. Three RTO/ISOs initiated mandatory capacity markets in 2006–2007: New York ISO (NYISO), PJM Interconnection (PJM), and ISO-New England (ISO-NE).
- The emergence of a large amount of unconventional natural gas production—the shale revolution—started in 2006–2007. The consequent drop in natural gas prices began in 2009 under the combined impacts of low demand during the economic recession and a significant increase in supply.
- The recession contributed to a significant drop in electricity demand in 2008, and it took several years for demand to return to 2008 levels. Although economic activity has picked up in recent years, electricity consumption and gross domestic product (GDP)—which grew together for decades—now appear less correlated as industries have become less energy-intensive and energy efficiency measures have taken full effect.
- Several environmental regulations implemented under statutes enacted in the 1970s and 1990s, which raise capital and operating costs for affected power plants, had compliance deadlines in the period 2010–2017.
- Driven in part by Federal and state policies, tax incentives, and mandates, significant quantities of variable renewable energy (VRE) resources—specifically wind and solar, and at levels high enough to alter traditional patterns of grid operation—began to impact certain areas around 2010.
- Also around 2010, demand response emerged as a way for customers to compete in most centrally-organized wholesale markets.

Because all of the above factors have emerged over the past 15 years—each affecting power supply and demand in different ways—looking at data since 2002 helps to reveal the impact and interactions of these changes. Additionally, EIA believes that the highly detailed EIA data used in this study (down to the level of individual generators) is most reliable for 2002 forward.

Further, the data used for this study include power plant fuel conversions as retirements for the original fuel source. This study reports power (e.g. generation capacity) and energy (e.g. production or consumption over time) in megawatts (MW) and megawatt-hours (MWh), respectively (unless otherwise noted). Finally, all generation capacity figures reported in this study are net summer capacity as opposed to nameplate (unless otherwise noted).

Defining Regions

The U.S. bulk power system (BPS) is a patchwork of different markets for electricity, shaped over time by technological changes, as well as state, regional, and Federal policies. This patchwork presents organizational and operational challenges, but its diversity also contributes to the system's robustness.

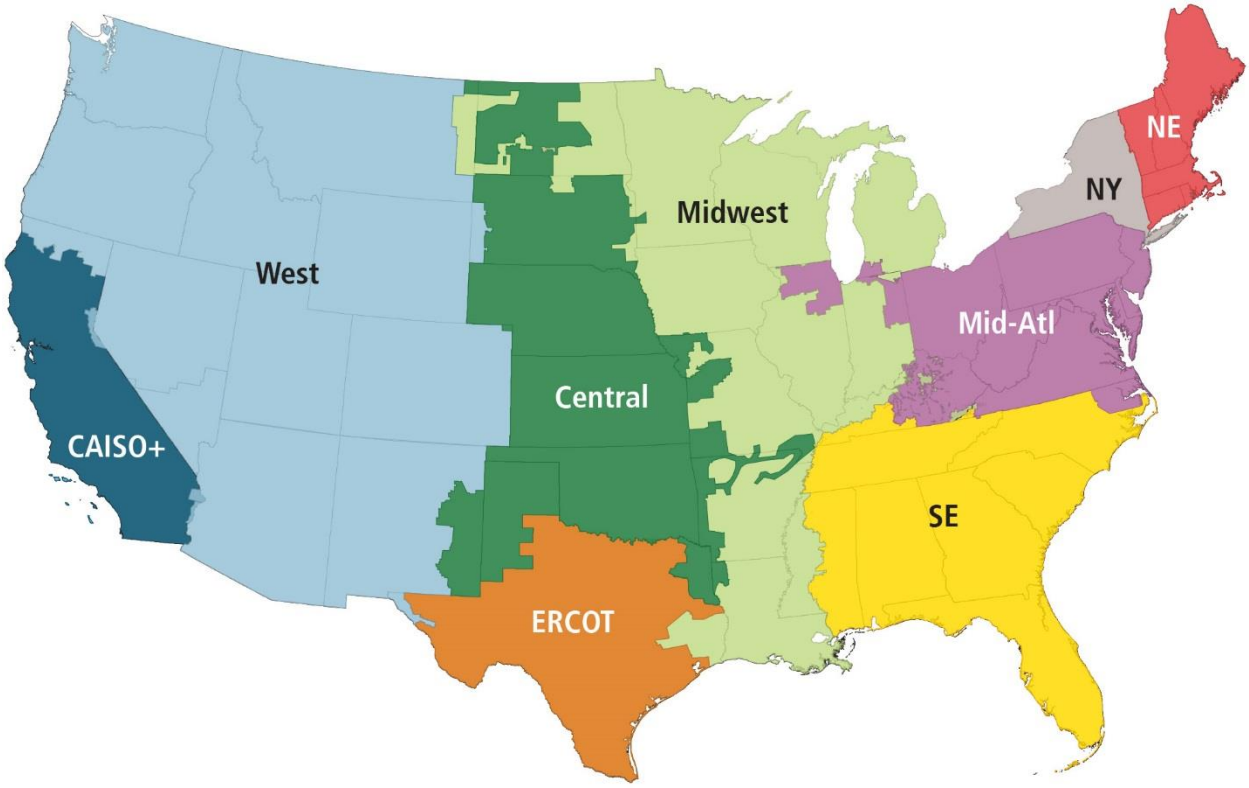
The U.S. power system in the lower 48 states[a] is divided into three synchronized grids: the Eastern Interconnection, the Western Interconnection, and the Electric Reliability Council of Texas (ERCOT).[b, 9] There are limited connections between the Eastern and Western Interconnections, and even fewer connections from ERCOT to the other grids.

Issues confronting the BPS vary widely across regions. This study divides the lower 48 states into nine regions that represent either individual or groups of electric systems, known as balancing authority areas (see Figure 1.1). Within these regions, there are 66 balancing authorities (which can be as small as individual utilities or as large as a multi-state region). Using nine balancing authority-based regions for this analysis is a useful way of aggregating electricity data and revealing regional trends.

[a] Both Alaska and Hawaii have unique islanded electric power systems that are not comparable to the rest of the Nation and thus are not included in this study. This is discussed in detail in a later section.

[b] For most purposes, ERCOT can be considered electrically isolated from the other grids. ERCOT is also not subject to most elements of the Federal Power Act and therefore economic regulation by the Federal Energy Regulatory Commission. A significant exception is Federal Energy Regulatory Commission oversight and regulation of power system reliability, which does apply to ERCOT.

Figure 1.1. Regions Used in This Study[10]



Seven of the nine regions analyzed in this study correlate primarily or directly to the seven ISOs and RTOs in the United States that supply about two-thirds of electricity delivered to end-use customers:[c]

- NE = ISO-NE
- NY = NYISO
- ERCOT = Electric Reliability Council of Texas
- Mid-Atl = PJM
- Midwest = Mid-Continent ISO (MISO)
- Central = Southwest Power Pool (SPP)
- CAISO+ = California ISO (plus smaller balancing areas in the state)

The two remaining regions include numerous balancing authorities, all of which lie outside RTO/ISO service areas:

- SE = Southeast
- West = non-CAISO+ Western Interconnection.

[c] The last four regions in this list include a few additional (mostly small) balancing authorities outside the formal ISO or RTO footprint.

Defining Baseload Generation

This study defines baseload generation as power plants that are operated in baseload patterns—that is, plants that run at high, sustained output levels and high capacity factors, with limited cycling or ramping. While this definition includes most nuclear, coal, and natural gas steam generators, it is not a given that every nuclear, coal, or natural gas steam generator is operated as a baseload plant, or that other technologies cannot function as baseload plants (such as hydroelectric generators). In addition, this study uses the term conventional generation to mean coal, nuclear, and natural gas power plants, regardless of how they are operated.[d]

Other organizations and publications use similar definitions. For example, PJM defines baseload generation as "those units which operate the great majority of hours of the year to meet load requirements."[11]

The North American Electric Reliability Corporation (NERC) offers an explanation as well:

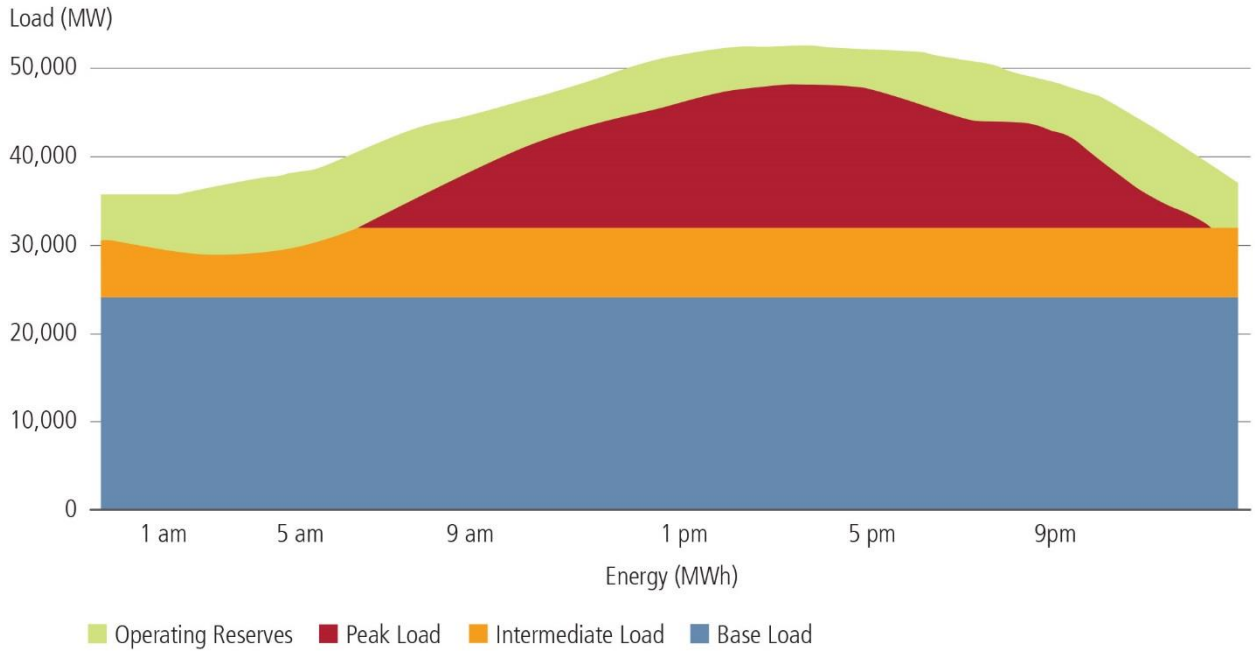
> There is a distinction between baseload generation and the characteristics of generation providing reliable "baseload" power. Baseload is a term used to describe generation that falls at the bottom of the economic dispatch stack, meaning [those power plants] are the most economical to run. Coal and nuclear resources, by design, are designed for low cost O&M [operation and maintenance] and continuous operation […]
>
> However, it is not the economics nor the fuel type that make these resources attractive from a reliability perspective. Rather, these conventional steam-driven generation resources have **low forced and maintenance outage** hours traditionally and have **low exposure to fuel supply chain issues**. Therefore, "baseload" generation is not a requirement; however, having a portion of a resource fleet with high reliability characteristics, such as low forced and maintenance outage rates and low exposure to fuel supply chain issues, is one of the most fundamental necessities of a reliable BPS. These characteristics ensure that "baseload" generation is more resilient to disruptions.[12]

The electricity industry has traditionally referred to baseload generation as the power plants that are used to meet "base" load—the minimum level of electricity that customers demand around the clock, as illustrated in Figure 1.2. Large nuclear, coal, natural gas steam, and hydroelectric plants have historically been used for baseload generation.[e] Baseload plants generally have high capital costs but low fuel costs, and they tend to be fairly fuel efficient. Although the output level of these plants can be changed, they are most economic—in terms of cost per unit of electricity produced—when operated at near-full capacity at all times (although hydroelectric plants are more flexible). Traditional baseload units tend to have longer start-up and shut-down times and generally move (ramp) slowly between production levels to avoid damaging plant components with thermal stress or metal fatigue (see Appendix C on cycling).

[d] QER 1.2 does not define the term baseload in its glossary. However, the report states in a caption on page 1-21 that "baseload is considered coal, nuclear, and natural gas combined-cycle plants."

[e] Other technologies that have traditionally operated as baseload include geothermal and biomass power plants. However, those technologies represent a relatively small portion of total U.S. electricity generation; while valuable for the grid reliability services they provide, they are not covered in this report.

Figure 1.2. Schematic of Typical Daily Load Curve Showing Base Load[13]



Intermediate or mid-merit plants are used to follow load, meeting daily variations in demand. Depending on the mix of generation resources available in different regions of the country and relative fuel prices, natural gas and/or coal units are typically used for load following. Short-duration demand peaks, which occur infrequently throughout the year, are generally met by natural gas units with high heat rates.[f] More recently, customer-provided demand response is helping to meet peak demand.

Analysis in Section 3 shows that many of the power plants that retired between 2002 and 2016 were used for baseload generation in the past, but were no longer operating in that role at the time of retirement due to changes in electricity market dynamics. With the sustained drop in natural gas prices, for example, natural gas-fired combined-cycle (NGCC) plants are currently a less costly source of baseload generation than coal or nuclear power in many regions of the country.

VRE resources such as wind and solar are beginning to serve more of minimum load, albeit at variable or intermittent output levels.[g] The proliferation of these sources has also led grid operators in some regions to place an increasing premium on flexible generation resources (e.g., NGCC units) that can help balance VRE variability by meeting base load and intermediate load, both of which are affected by a

[f] According to EIA, "Heat rate is one measure of the efficiency of a generator or power plant that converts a fuel into heat and into electricity. The heat rate is the amount of energy used by an electrical generator or power plant to generate one kilowatt-hour (kWh) of electricity." https://www.eia.gov/tools/faqs/faq.php?id=107&t=3.

[g] For the purposes of this study, wind and solar are referred to as VRE. Terms such as "non-dispatchable" and "intermittent" may also apply to these technologies, but for consistency, this study uses the term variable. In contrast, some renewables are dispatchable—that is, sources that can provide power to the grid within sub-hourly time scales to match demand during any 24-hour period. Dispatchable renewables include sources such as biofuels, geothermal, and hydropower (with the caveat on hydropower that it may only be seasonally dispatchable in some cases).

changing net load profile.[h] These factors, among others, have collectively lessened the immediate need for traditional baseload resources in certain regions, but still speak to the need for baseload generation.

Defining Premature Retirement

The dictionary definition of premature is "happening … or performed before the proper, usual or intended time."[14] The Department does not have an official definition for the term "premature retirement"[i] with respect to power plants, as the term is highly subjective. Below are some of the prevailing viewpoints and associated meanings:

- ✓ Power plant engineers may think a power plant retired prematurely if it has not yet run to the end of its nominal design life (for instance, approximately 40 years for post-1970 coal plants) or through the term of reasonable plant life extension modifications.
- ✓ An RTO/ISO or reliability organization may think a power plant retirement is premature if its continued operation is still required to deliver Essential Reliability Services (ERS)[j] in that location (in which case the operator may delay retirement by designating it a "reliability-must-run" resource).
- ✓ A policymaker or legislator may think a power plant has been forced to retire prematurely if the plant delivers benefits that the state or society values, such as emissions-free energy, local jobs, or maintaining local generation.
- ✓ A mayor or employee may think a power plant is retiring prematurely if the retirement causes harms to the community and the individuals who work there.
- ✓ A merchant competitor that built or acquired a power plant may think its plant has been forced to retire prematurely if the merchant has not been able to recover its investment in the plant through sales of energy and capacity or through other revenue streams.
- ✓ A vertically integrated utility executive may think a power plant has been forced to retire prematurely if the utility has not yet fully recovered its rate-based capital investment in the plant and its return on that rate base.
- ✓ Nuclear or hydroelectric plant owners and regulators may think a power plant has retired prematurely if it has not yet run through the full term of its operating license and/or license extension. Federal Energy Regulatory Commission (FERC) hydro licenses run for up to 50 years with potential reauthorizations of 30–50 years, and Nuclear Regulatory Commission (NRC) nuclear operating licenses run for 40 years with potential 20-year extensions.
- ✓ Electricity economists may think a power plant retired has prematurely if the plant was still able to sell electricity competitively against other energy sources but was required to close due to policy directives. On the other hand, economists may also think a power plant retired

[h] "Net load" is the instantaneous difference between total customer electricity demand (load) and VRE generation.

[i] QER 1.2—*Transforming the Nation's Electricity System: The Second Installment of the Quadrennial Energy Review*—discussed "premature nuclear retirements" but did not explicitly define the term. For example, in Chapter 3, page 24, the report notes: "When analyzing the impacts of **premature nuclear retirements** on power generation in the state, a state of Illinois report considered a scenario in which 80 percent of the replacement generation was coal. Other analysis concludes that roughly 75 percent of the at-risk nuclear generation nationwide would be replaced with fossil generation, largely powered with natural gas." [notes omitted, emphasis added]

[j] See Section 4.1.1 for a discussion of ERS.

prematurely if the plant provided un-priced benefits to society that, if priced, would have made the plant profitable.

- ✓ A long-term planner and risk manager may think a power plant has retired prematurely if it offered valuable diversity, reliability, resilience, and optionality benefits that are not yet fully recognized, valued, and/or compensated.

Each of these viewpoints represents a valid perspective, particularly those of grid operators and other institutions responsible for reliability. While stakeholders may maintain that a power plant has been forced to retire prematurely based on one or more of the considerations above, the results of this study show that some observed power plant retirements were appropriate and consistent with markets as they are currently functioning. In other words, not every power plant retirement is cause for alarm.

However, NERC is concerned with the trend of retirements as it relates to reliability and resilience. NERC wrote in response to the April 14 memo:

> As conventional resources **prematurely** retire, sufficient amounts of essential reliability services, such as frequency and voltage support, ramping capability, etc., must be replaced based on the configuration and needs of the system.[15] [emphasis added]

Given the difficulty in assigning a single definition to premature retirement, as well as the subjective nature of such a definition, this study does not attempt to determine whether any *specific* power plant retirements have been premature. Instead, this study assesses the various factors that contribute to power plant retirement *trends*.

Topics Beyond the Scope of This Study

This study does not directly address several topics for the following reasons:

- **Cybersecurity** is a critical component to ensuring the reliable and resilient operation of the Nation's energy infrastructure. Existing and emerging cybersecurity threats can affect any aspect of the electric sector, ranging from power plants, to transmission and distribution systems, to customers and end-use devices. The December 2015 attack on the Ukrainian electricity system and the 2012 Shamoon virus targeting the energy sector in Saudi Arabia, for example, were wake-up calls.[16]

  DOE takes these threats seriously and is designated as the Federal Government's lead Sector-Specific Agency for cybersecurity for the energy sector, which entails supporting the cyber protection of the Nation's critical energy infrastructure.[k] However, while cybersecurity is a significant concern and top priority, it is not addressed in this report because it is the subject of an upcoming joint report between DOE and the Department of Homeland Security being prepared in response to Executive Order No. 13800, *Strengthening the Cybersecurity of Federal Networks and Critical Infrastructure*.

- **Alaska and Hawaii**: While the broad trends discussed in this report apply in Alaska and Hawaii as well as the lower 48 states, many of this study's economic observations do not directly apply to the power plants in the Hawaii and Alaska power systems, as they are not large, interconnected energy markets, and utility system operators in the states face unique operational and fuel supply chain considerations.

[k] For more information, visit DOE's website on the Department's cyber activities: https://www.energy.gov/national-security-safety/cybersecurity.

The Hawaii and Alaska power systems are remote, vertically integrated systems with plant sizes that tend to fall below the size screens used in this study. The average generating unit sizes in Hawaii and Alaska are 18 MW and 5 MW, respectively, compared to an average unit size of 70 MW in the lower 48 states.[17] Because neither state is interconnected with any of the major U.S. interconnections, or to any transmission or distribution network in Canada, utilities in both states must self-supply all ERS.[l] As a result, utilities in these isolated systems might consider different parameters for reliability in their system planning compared to utilities in the contiguous United States, who can obtain reliability services and products in real time through markets and bilateral transactions.[18] Their experiences, however, may inform the efforts of utilities in the contiguous U.S. seeking to better manage rural systems and effectively integrate VRE and microgrids.

- **Geothermal, biomass, and combined heat and power** plants are often operated as baseload plants, operating at a relatively stable level over a long period of time. However, because these types of plants are not as prevalent or widespread as gas, coal, and nuclear plants, this study did not perform detailed analyses of trends and closures for these technologies.

[l] In 2014, an intertie to the Western Interconnection of British Columbia was proposed to the Alaska Energy Authority in order to bring power to Alaska. However, as of 2016, no further work on the project had been completed due to economic reasons. http://energy-alaska.wikidot.com/railbelt.

2 Findings of This Study

This study identified several critical issues central to protecting the long-term reliability of the electric grid in accordance with the April 14 memo, which asked staff to explore:

1) **The evolution of wholesale electricity markets, including the extent to which Federal policy interventions and the changing nature of the electricity fuel mix are challenging the original policy assumptions that shaped the creation of those markets.**

While centrally-organized markets have achieved reliable wholesale electricity delivery with economic efficiencies in their short-term operations, changing circumstances have challenged both centrally-organized and, to a lesser extent, vertically-integrated markets.[m]

- To date, wholesale markets have withstood a number of stresses. While markets have evolved since their introduction, they are currently functioning as designed—to ensure reliability and minimize the short-term costs of wholesale electricity—despite pressures from flat demand growth, Federal and state policy interventions, and the massive economic shift in the relative economics of natural gas compared to other fuels. The resulting low average wholesale energy prices, while beneficial for buyers of wholesale electricity, represent a critical juncture for many existing baseload generation resources and their role in preserving reliability and resilience.[n]
- Market designs may be inadequate given potential future challenges. VRE—with near-zero marginal costs and if at high penetrations—will lower wholesale energy prices independent of effects of the current low natural gas prices. This would put additional economic pressure on revenues for traditional baseload (as well as non-baseload) resources, requiring careful consideration of continued market evolutions.
- Markets need further study and reform to address future services essential to grid reliability and resilience. System operators are working toward recognizing, defining, and compensating for resource attributes that enhance reliability and resilience (on both the supply and demand side). However, further efforts should reflect the urgent need for clear definitions of reliability- and resilience-enhancing attributes and should quickly establish the market means to value or the regulatory means to provide them.

Evolving market conditions and the need to accommodate VRE have led to the increased flexible operation of generation and other grid resources. Some generation technologies originally designed to operate as baseload were not intended to operate flexibly, and in nuclear power's case, do not have a regulatory regime that allows them to do so.

---

[m] This study also refers to vertically integrated markets as bilateral markets.

[n] Former FERC Commissioner Tony Clark summarizes today's changing demands on centrally-organized markets: "Affordable power was the goal when markets were created. The current markets are still procuring affordable power, but many state public policy makers no longer see that as the only goal […] other public policy goals [include…] incenting in-state jobs, promoting 'green' energy or other politically favored resources, preserving carbon-free resources, and retaining substantial tax revenues to state and local government." Clark goes on to say, "[Markets] were never designed for job creation, tax preservation, politically popular generation, or anything other than reliable, affordable electricity." http://www.wbklaw.com/uploads/file/Articles-%20News/2017%20articles%20publications/Market%20Identity%20Crisis%20Final%20(7-14-17).pdf.

- Generation from VRE can change widely over the course of a single day, which requires dispatchable power plants to be operated more nimbly. Additionally, in some areas of the country, there may be over-generation from VRE at some points in a day, which drives prices to almost zero yet requires quick-ramping assets when VRE subsides. Taken together, these trends have placed a premium on flexible output rather than the steady output of traditional baseload power plants. This flexibility is generally provided by generation resources. However, non-generation sources of flexibility—such as flexible demand, increased transmission, and energy storage technologies—are being explored as ways to enhance system flexibility.

Society places value on attributes of electricity provision beyond those compensated by the current design of the wholesale market.

- Americans and their elected representatives value the various benefits specific power plants offer, such as jobs, community economic development, low emissions, local tax payments, resilience, energy security, or the national security benefits associated with a nuclear industrial base. Most of these benefits are not recognized or compensated by wholesale electricity markets, and this has given rise to a variety of state and private efforts that include keeping open or shutting down established baseload generators and incentivizing VRE generation.

2) Whether wholesale energy and capacity markets are adequately compensating attributes such as onsite fuel supply and other factors that strengthen grid resilience and, if not, the extent to which this could affect grid reliability and resilience in the future.

Markets recognize and compensate reliability, and must evolve to continue to compensate reliability, but more work is needed to address resilience.

- Reliable and affordable electricity is essential to the modern economy, including the manufacturing, services, and financial sectors. NERC's most recent annual *State of Reliability* report concludes that during 2016, the "bulk power system reliability remained within defined performance objectives to provide an Adequate Level of Reliability (ALR)."[o] NERC reached the same conclusion for 2013–2015. However, in a May 2017 letter to the Secretary of Energy, NERC pressed the importance of reliability issues that require attention, including maintaining ERS as conventional generation retires and ensuring flexibility and sufficient transmission to supplement and offset VRE.[19] These issues are indicative of the technological and institutional changes that are now affecting the electricity sector, and dealing with these issues will require new levels of coordination and collaboration among the sector's many constituencies. Presently, BPS reliability is adequate despite the retirement of a portion of baseload capacity and unique regional hurdles posed by the changing resource mix.

- Fuel assurance is a growing consideration for the electricity system. Maintaining onsite fuel resources is one way to improve fuel assurance, but most generation technologies have experienced fuel deliverability challenges in the past. While coal facilities typically store enough

[o] NERC defines ALR as "the state that the design, planning, and operation of the Bulk Electric System (BES) will achieve when the [five] listed Reliability Performance Objectives are met." These objectives are detailed at http://www.nerc.com/pa/Stand/Resources/Documents/Adequate_Level_of_Reliability_Definition_(Informational_Filing).pdf.

fuel onsite to last for 30 days or more, extreme cold can lead to frozen fuel stockpiles and disruption in train deliveries. Natural gas is delivered by pipeline as needed. The NERC letter to DOE emphasized ensuring natural gas fuel supply and mitigating delivery vulnerabilities. Capacity challenges on existing pipelines combined with the difficulty in some areas of siting and constructing new natural gas pipelines, along with competing uses for natural gas such as for home heating, have created supply constraints in the past. Supply constraints can create increased price risk and, in extreme cases, could impact reliability.[p]

- Recent severe weather events have demonstrated the need to improve system resilience. The range of potential disruptive events is broad, and the system needs to be designed to handle high-impact, low probability events. This makes it very challenging to develop cost-effective programs to improve resilience at the regional, state, or utility levels. Planning, practice, and coordination on an all-hazards basis and having a mix of resources and fuels available when a major disturbance occurs are both essential to fast response. Work still remains to identify facilities that merit hardening; stage periodic exercises and drills so that governmental agencies and utilities are prepared for emergencies; and ensure that wholesale electricity markets are designed to recognize and incentivize investments that would achieve or enhance resilience-related objectives.
- Significant progress is already being made to understand what is needed to maintain power system reliability under changing market conditions, but more work is needed to understand what can be done to maintain resilience in a variety of conditions as the grid changes over the coming years. Further, low natural gas prices are driving greater use of natural gas for electricity generation, which has made exposure to natural gas price risk related to availability a growing concern in several regions. There are tradeoffs between multiple desirable attributes of the grid. For example, within power systems, it may be the case that a more reliable and resilient system is more costly than the least-cost system that a centrally-organized wholesale market is intended to deliver. Similarly, policies that seek to deliver more jobs, reduce pollution, or reduce risk may require more upfront investment at an initially higher cost to society as a whole than a least-cost system. It is important that policymakers have a clear understanding of the true costs and benefits of services to the grid, as well as an understanding of the tradeoffs between desirable attributes like reliability, flexibility, and affordability.

[p] Indeed, ISO-NE has repeatedly expressed that reliability and resilience concerns are not being adequately addressed by the New England region on natural gas.

3) The extent to which continued regulatory burdens, as well as mandates and tax and subsidy policies, are responsible for forcing the premature retirement of baseload power plants.

The recent and unprecedented rise of natural gas as a top electricity generation resource, the increase in VRE penetration, the flattening of electricity demand growth, and a host of policy issues—regulations, mandates, and subsidies at the state and Federal levels—have negatively impacted traditional baseload generation, particularly coal and nuclear power plants.

Between 2002 and 2016, 132,000 MW of generation capacity retired—representing about 15 percent of the total 2002 installed base—and 390,500 MW of new capacity was added. While power plants retire for a variety of reasons, several factors have contributed to recent retirements and continuing pressure for additional retirements.

The biggest contributor to coal and nuclear plant retirements has been the advantaged economics of natural gas-fired generation.

- Low-cost, abundant natural gas and the development of highly-efficient NGCC plants resulted in a new baseload competitor to the existing coal, nuclear, and hydroelectric plants. In 2016, natural gas was the largest source of electricity generation in the United States—overtaking coal for the first time since data collection began.[20] The increased use of natural gas in the electric sector has resulted in sustained low wholesale market prices that reduce the profitability of other generation resources important to the grid. The fact that new, high-efficiency natural gas plants can be built relatively quickly, compared to coal and nuclear power, also helped to grow gas-fired generation. Production costs of coal and nuclear plants remained somewhat flat, while the new and existing, more flexible, and relatively lower-operating cost natural gas plants drove down wholesale market prices to the point that some formerly profitable nuclear and coal facilities began operating at a loss. The development of abundant, domestic natural gas made possible by the shale revolution also has produced significant value for consumers and the economy overall.

Another factor contributing to the retirement of power plants is low growth in electricity demand.

- Growth of total electricity use has slowed from averaging 2.5 percent annually in the late 1990s, to averaging 1.0 percent annually from 2000 to 2008, to remaining roughly flat since then.[21] Changes in electricity demand—particularly the apparent decoupling of economic output and electricity demand—have been driven in part by energy efficiency policies. The combination of slow growth in electricity demand and the 390,500 MW of capacity additions from 2002 to 2016 made significant amounts of older, higher-cost capacity redundant.

Dispatch of VRE has negatively impacted the economics of baseload plants.

- Since 2007, the contribution to total generation from wind and solar has grown quickly, accelerated by government policies and mandates. State renewable portfolio standards (RPS) have been the largest contributor—associated with 60 percent of VRE growth since 2000—followed by Federal tax credits and government research (which contributed to the dramatic drop in wind and solar technology costs). Because these resources have lower variable operating costs than traditional baseload generators, they are dispatched first and displace baseload resources when they are available.
- Participants on a panel of economists at a May 2017 FERC technical conference cited state-level RPS and Federal tax credits for VRE as examples of wholesale market impacts and distortions.

Competition from resources that benefit from such policies[q] reduces revenues for traditional baseload power plants by lowering the wholesale electric prices they receive and by displacing a portion of their output.

Investments required for regulatory compliance have also negatively impacted baseload plant economics, and the peak in baseload plant retirements (2015) correlated with deadlines for power plant regulations as well as strong signals of future regulation.

- A suite of environmental regulations scheduled for implementation between 2011 and 2022 has had varying degrees of effects on the cost of generation. For example, the largest number of coal plant retirements occurred in 2015—the deadline for coal and oil plants to add pollution control equipment for Mercury and Air Toxics Standard (MATS) compliance. In the same year, the Environmental Protection Agency (EPA) finalized its Clean Power Plan, which, if fully implemented, would place additional pressure on coal-fired generation. Nuclear power plants also face regulatory costs—principally the Cooling Water Intake Rule. Three nuclear plants that announced closure (Oyster Creek, Diablo Canyon, and Indian Point) have cited disputes with their respective states, who implement the rule, as among the reasons for plant retirement.

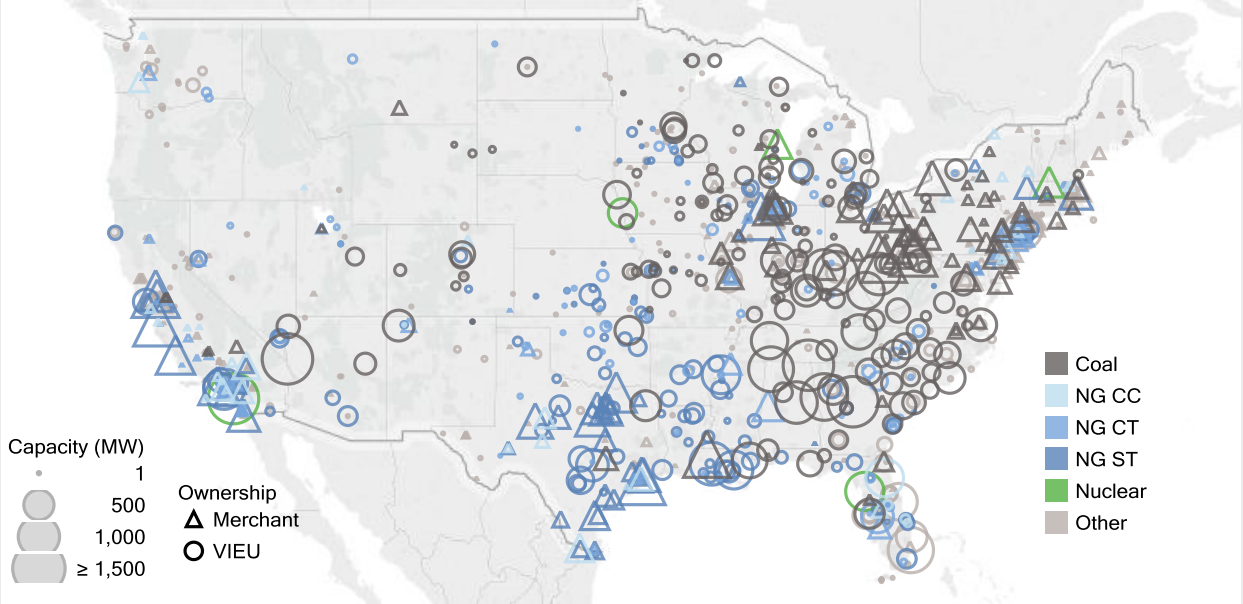
Ultimately, the continued closure of traditional baseload power plants calls for a comprehensive strategy for long-term reliability and resilience. States and regions are accepting increased risks that could affect the future reliability and resilience of electricity delivery for consumers in their regions. Hydropower, nuclear, coal, and natural gas power plants provide ERS and fuel assurance critical to system resilience. A continual comprehensive regional and national review is needed to determine how a portfolio of domestic energy resources can be developed to ensure grid reliability and resilience.

[q] These same economists also cited other "out-of-market" interventions as distorting efficient price formation in wholesale markets, such as recently enacted and pending state laws that provide support to existing nuclear units. During the economist's panel discussion at the FERC May 2017 technical conference, the phrase "subsidies beget subsidies" was used.

3 Power Plant Retirements

A combination of factors is causing power plant retirements, including low natural gas prices, wholesale competition, low customer demand growth, regulation-driven cost increases, and the growth of VRE. As Figure 3.1 shows, the types, magnitude, and timing of conventional power plant retirements vary regionally.

Figure 3.1. Location of Coal, Natural Gas, Nuclear, and All Other Retirements, 2002–2016[22, r]

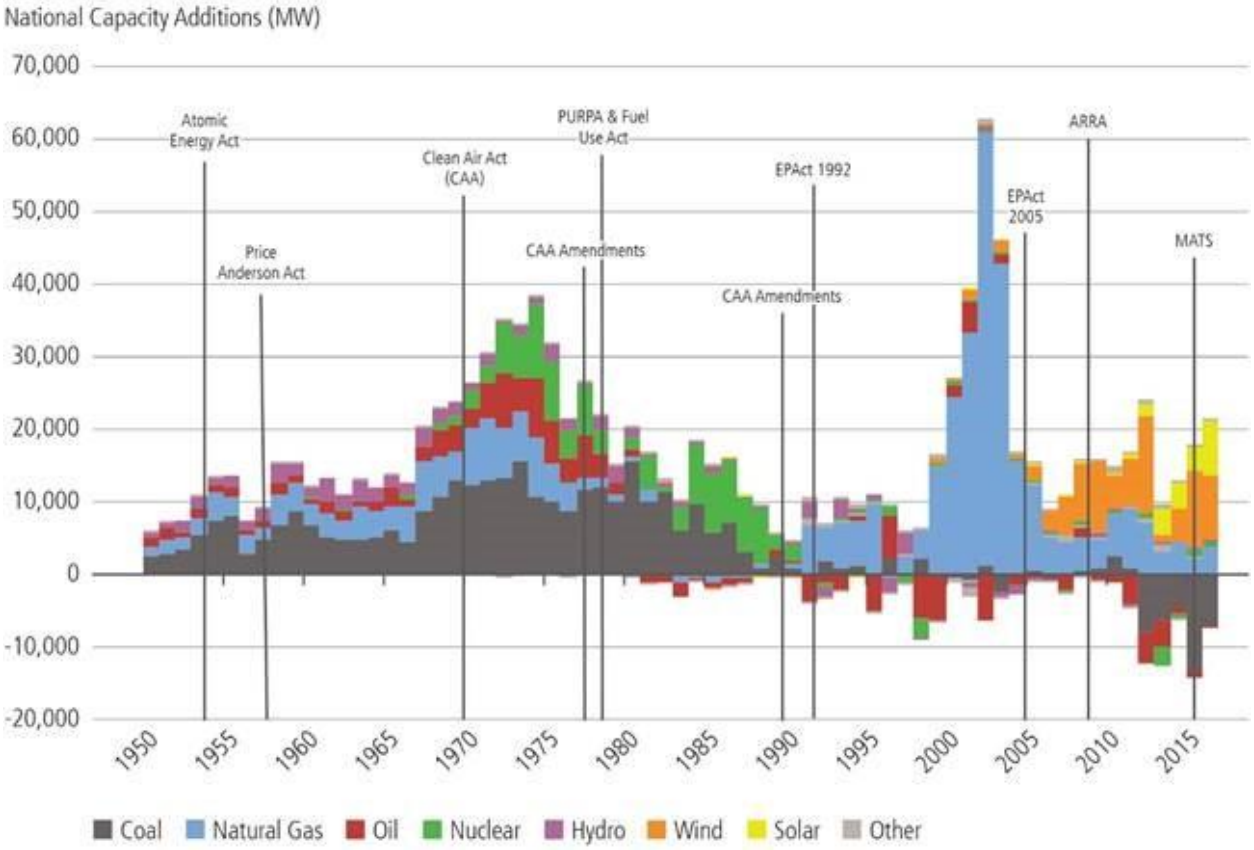


To understand observed power plant capacity *retirements*, it is useful to begin with an examination of historical capacity *additions*. From 1950 to 2015, capacity additions of different generation technologies tended to come in waves that were largely influenced by policy, fuel costs, and technology development (see Figure 3.2). Coal expansion was highest from 1950 to 1990, nuclear power was widely deployed in the 1970s and 1980s, natural gas capacity additions peaked in the early 2000s and continue through today, and VRE has grown rapidly over the last decade.[s]

[r] VIEU stands for vertically integrated electric utilities.

[s] Not depicted: prior to the 1950s, hydropower was a large source of generation capacity additions, the vast majority of which is still operational today. https://www.eia.gov/todayinenergy/detail.php?id=30312.

Figure 3.2. Net Generation Capacity Additions and Retirements[t23]



Power plant retirements have accelerated since 2011, and retirement trends vary significantly by generation source. For instance, the current wave of nuclear plant retirements only occurred over the last five years.[u] Some of the nuclear units now closing are doing so because of state policy pressure (as with California's Diablo Canyon, New Jersey's Oyster Creek, and New York's Indian Point), and some have had maintenance issues that were too costly to fix. However, most plants are closing or threatening closure because–given the economics in some regions—they have become unable to compete against primarily low-cost, gas-fired generation and, to a lesser extent, subsidized and mandated VRE in a low electricity demand environment.

The design of traditional baseload power plants assumed operations primarily at a constant output level with limited cycling (see Appendix C).[24] As the electricity system continues to evolve and market conditions change, these plants are increasingly being moved into load-following operations, or are

[t] Acronyms: Clean Air Act (CAA), Energy Policy Act of 1992 (EPAct 1992), Energy Policy Act of 2005 (EPAct 2005), Investment Tax Credit (ITC), Production Tax Credit (PTC).

[u] However, we note that 29 U.S. nuclear power plants retired from 1974 through 2001, including 13 power plants in the commercial utility nuclear fleet sized at 700 MW or larger. These plants retired for a variety of reasons, including damage (Fort St. Vrain), safety or operational difficulties (Three Mile Island 2, Zion 1 & 2, Millstone 1), costly safety requirements (Humboldt Bay), and state or utility policy choices (Rancho Seco, Trojan, Indian Point 1). This study only looks at the nuclear units in operation in 2002 and beyond.

required to more frequently adjust the load and the on/off dispatch of their units. The extra costs incurred to do so can affect a retirement decision.

QER 1.2 discusses these issues:

> Currently, the changing electricity sector is causing the closure of many coal and nuclear plants in a shift from recent trends. From 2000 through 2009, power plant retirements were dominated by natural gas steam turbines. Over the past 6 years (2010–2015), power plant retirements were dominated by coal plants (37 GW), which accounted for over 52 percent of recently retired power plant capacity. Over the next 5 years (between 2016 and 2020), 34.4 GW of summer capacity is planned to be retired, and 79 percent of this planned retirement capacity are coal and natural gas plants (49 percent and 30 percent, respectively). The next largest set of planned retirements are nuclear plants (15 percent).[25]

Retirements typically can be tied to the units' inability to compete economically, but the factors complicating a given plant's economics can be numerous and can compound each other. Currently, these factors include low wholesale electricity prices (driven by competing generators with low marginal costs, as well as subsidies); higher operating costs from unit age or lower efficiency; and looming capital needs, including compliance with safety and/or environmental regulations; among others. Further, minimal growth in electricity demand has compounded the impact of VRE policy; in an era of low-cost natural gas and increasing levels of state-mandated renewable generation—for example, a 20-percent share of wind and solar by 2020—lack of demand growth means natural gas and new VRE added to meet state mandates compete with existing conventional generation to satisfy a static level of demand.

A review of coal, nuclear, and natural gas retirements to date shows that power plant retirements reflect regional patterns of generation development, state policies, and differences in market structure across regions. However, national patterns also emerge—Figure 3.3 shows that a significant amount of capacity (the highest on record) retired in 2015, coinciding with the MATS compliance deadline (which applied to coal- and oil-fired units across the country) as well as the finalization of the Clean Power Plan rule.

Figure 3.3. Retirements of Coal, Natural Gas, Nuclear, and Other Generating Units, 2002–2022[26]

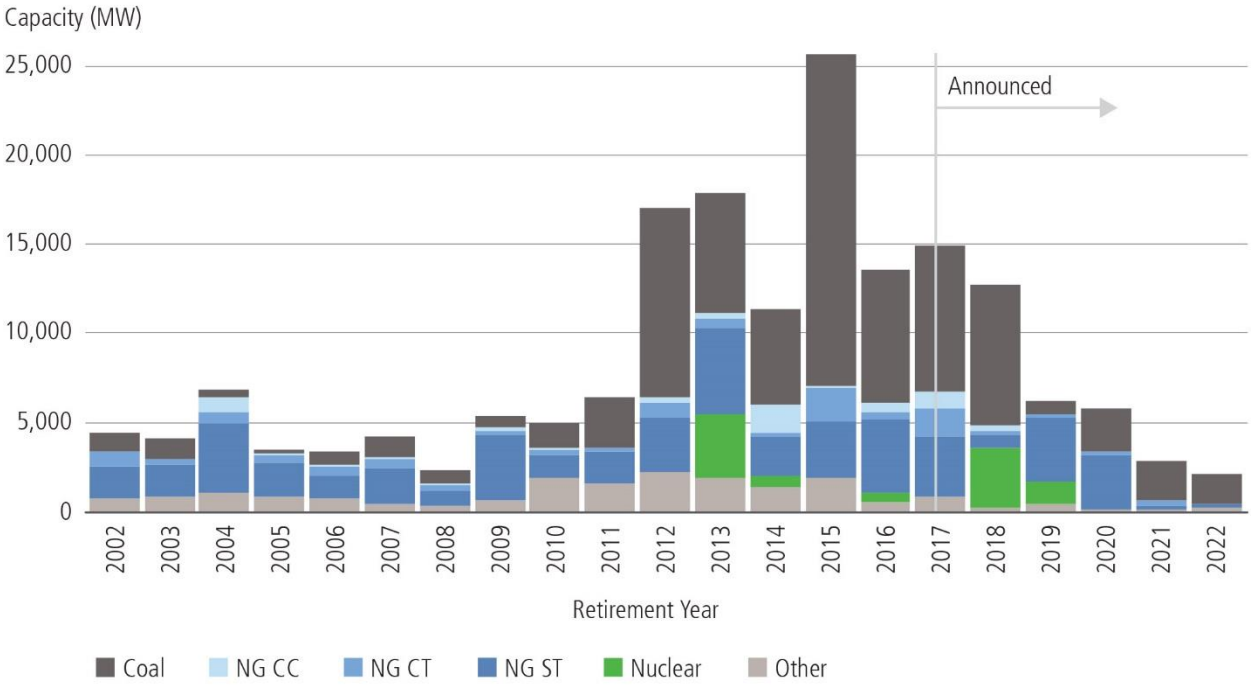
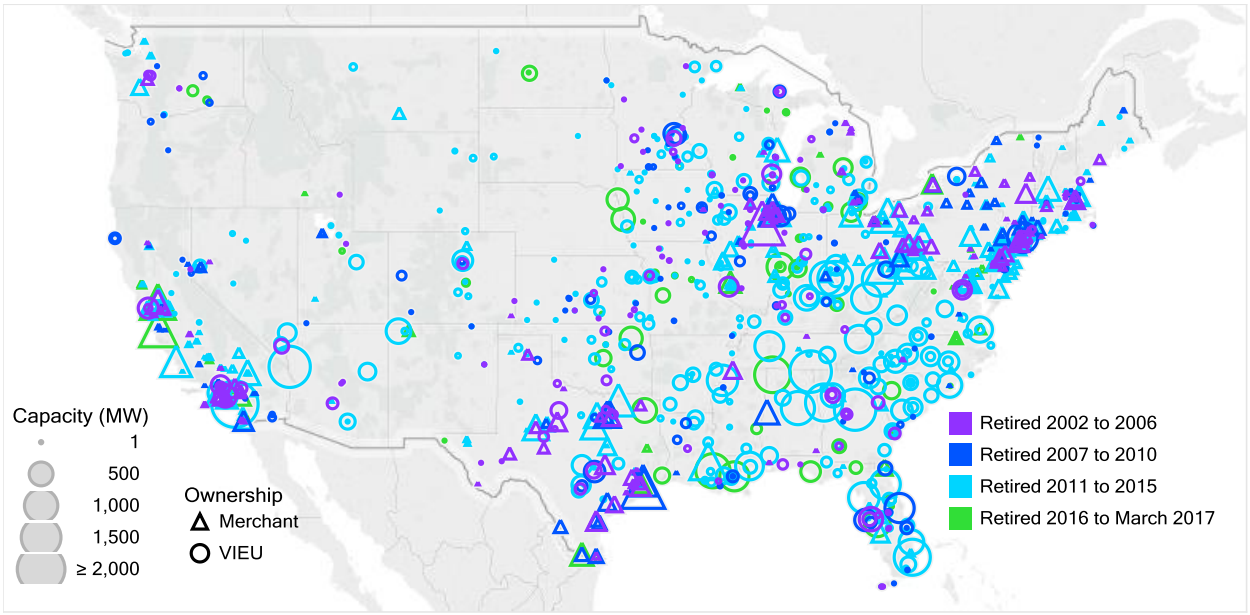


Figure 3.4 highlights retirement trends by ownership type (i.e., merchant vs. VIEU) and time period. Merchant plants accounted for nearly 70 percent of retired capacity during the period 2002–2010 (depicted as triangles below; note how most of the triangles are purple and dark blue). VIEU plants tended to retire later (depicted as circles below; note how most of the circles are light blue and green). The merchant vs. VIEU comparison indicates that market structure is a significant factor in power plant retirements, particularly the timing of retirements.

Figure 3.4. Retirements by Date, Location, Ownership, and Capacity[27]



The data displayed in Figure 3.4 is categorized into four time frames because a variety of economic trends and regulatory events occurred throughout the period 2002–2017:

- During the period 2002–2006 (shown in purple), VIEU plants retired or sold many of their generating assets to third parties through state-initiated processes collectively known as restructuring. During the late 1990s, many states passed legislation initiating restructuring concurrent with the creation of several RTOs and ISOs. The majority of retirements occurring during this period were smaller, older merchant power plants in restructured areas including California, Texas, the Northeast, and the mid-Atlantic region.
- The period 2007–2010 (shown in dark blue) saw early growth of subsidized utility-scale wind generation; the economic recession from 2008 through 2011; and the start of the shale revolution in 2006–2007, with natural gas prices starting a downward trend. Also in this time frame was the 2007 U.S. Supreme Court decision of *Massachusetts v. EPA*, finding that the EPA has the authority to regulate carbon dioxide (CO_2) and other greenhouse gases (GHGs), opening the door to further regulation under the Clean Air Act.[28] Older, less fuel efficient natural gas-fired plants retired early in this period, but the fall in natural gas prices starting in 2009 also began to force the shutdown of smaller, older coal and oil plants in 2009.
- In the period 2011–2015 (shown in light blue), low natural gas prices proved to be a long-lasting rather than a short-term phenomenon. The compliance deadline for MATS converged with tightening pollution limits in sulfur dioxide (SO_2) and nitrogen oxide (NO_X) trading programs. Many of the coal and oil retirements in this period were plants whose owners chose to shut down a plant rather than invest in costly environmental remediation measures. Further, the EPA's final Clean Power Plan rule was finalized during this time.[v] This period had the most power plant retirements, with a marked increase in California, the mid-Atlantic, Midwest, and Southeast. During this period, it also became clear that a portion of the customer electricity demand lost from the recession was not going to reappear in the near term, which meant that electricity demand would not support the higher-cost plants that occupied higher positions on the supply curve.
- In 2016 and going forward (shown in green), power plant retirements are and may continue to be driven by continued economic challenges in the form of market dynamics and compliance costs of regulations, as well as operational pressures from a changing resource mix.

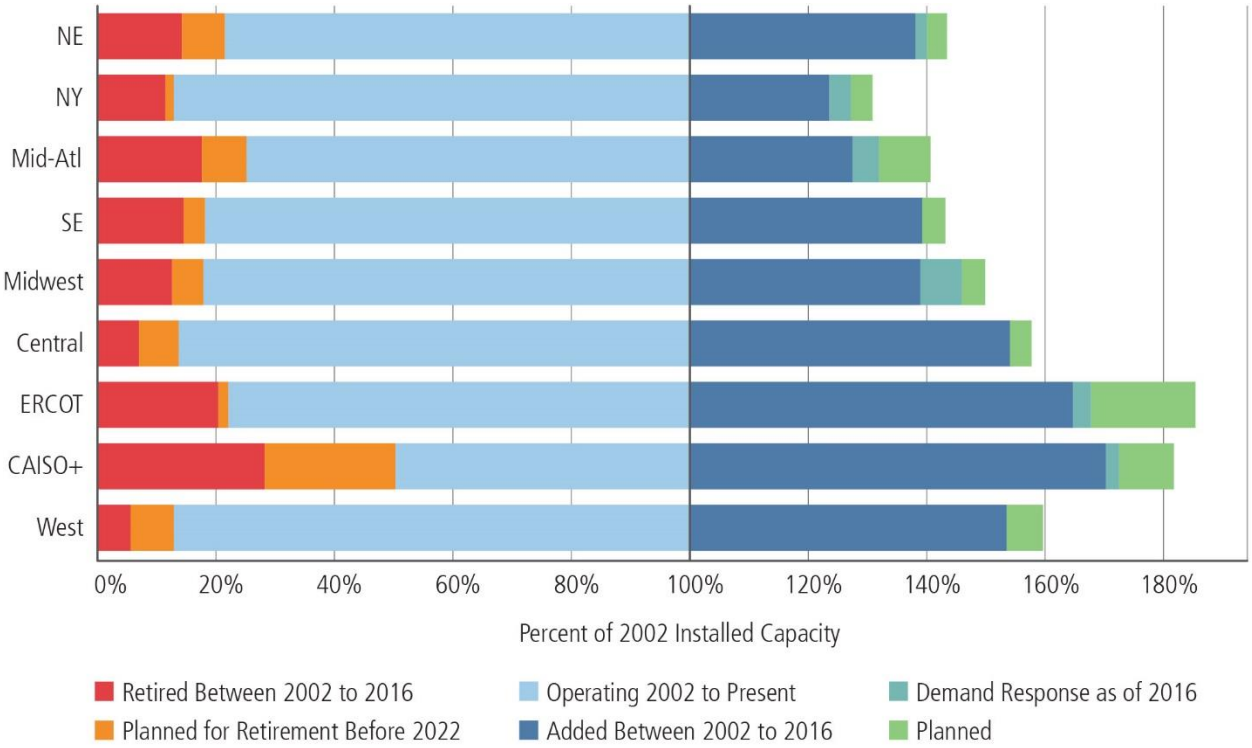
Figure 3.5 shows generation capacity, additions, retirements, announced retirements, and demand response[w] as a percentage of 2002 total installed net summer capacity in each region. The graphic shows that in every region except CAISO+, the proportion of retirements between 2002 and 2016 (in

[v] Although the Clean Power Plan was later stayed by the Supreme Court, the investment uncertainty around the time of the final rule made reinvestment in coal technology a difficult decision for plant owners. https://www.iaee.org/ej/ejexec/EJ391_ExecSum_Morris.pdf.

[w] Demand response is "a voluntary program offered by independent system operators/regional transmission organizations, local utility service providers, or third parties, which compensate end-use (retail) customers for reducing and/or changing the pattern of their electricity use (load) over a defined period of time, when requested or automatically instructed to do so during periods of high power prices or when the reliability of the grid is threatened." https://energy.gov/epsa/quadrennial-energy-review-second-installment.

orange) is 20 percent or less of the total installed capacity available in 2002 (in red, orange, and light blue). The figure also shows that the amount of new capacity added (dark blue) exceeds the combined amounts of capacity retired (in red) and planned for retirement (in orange) in every region over the study period.[x]

Figure 3.5. Operating Generation Capacity, Additions, Retirements, and Announced Retirements by Region for All Generation Types, January 2002–December 2022[29]

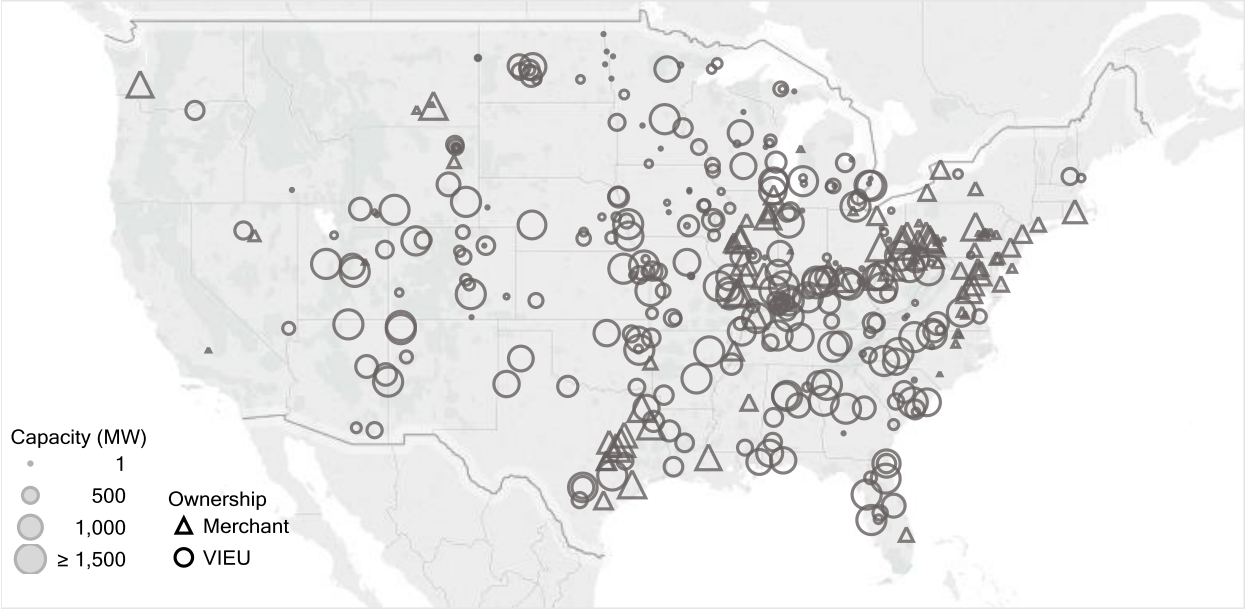


3.1 Coal Plant Retirements

There were approximately 306,000 MW[30] of coal-fired power plants in the United States at the start of 2002 and 270,000 MW[31] at the end of 2016, representing a net retirement of approximately 36,000 MW (about 12 percent) of coal capacity. The remaining fleet of coal-fired generators covers most of the lower 48 states, with the exception of the Northeast, Northwest, and California, as shown in Figure 3.6.

[x] While the graphic includes currently planned additions in EIA's data, this figure does not show *generation* (megawatt-hour) or technology type, and most of planned and added *capacity* (megawatt) comes from new natural gas and VRE sources that do not meet the NERC baseload characteristic discussed earlier.

Figure 3.6. Location of the Existing Coal Fleet

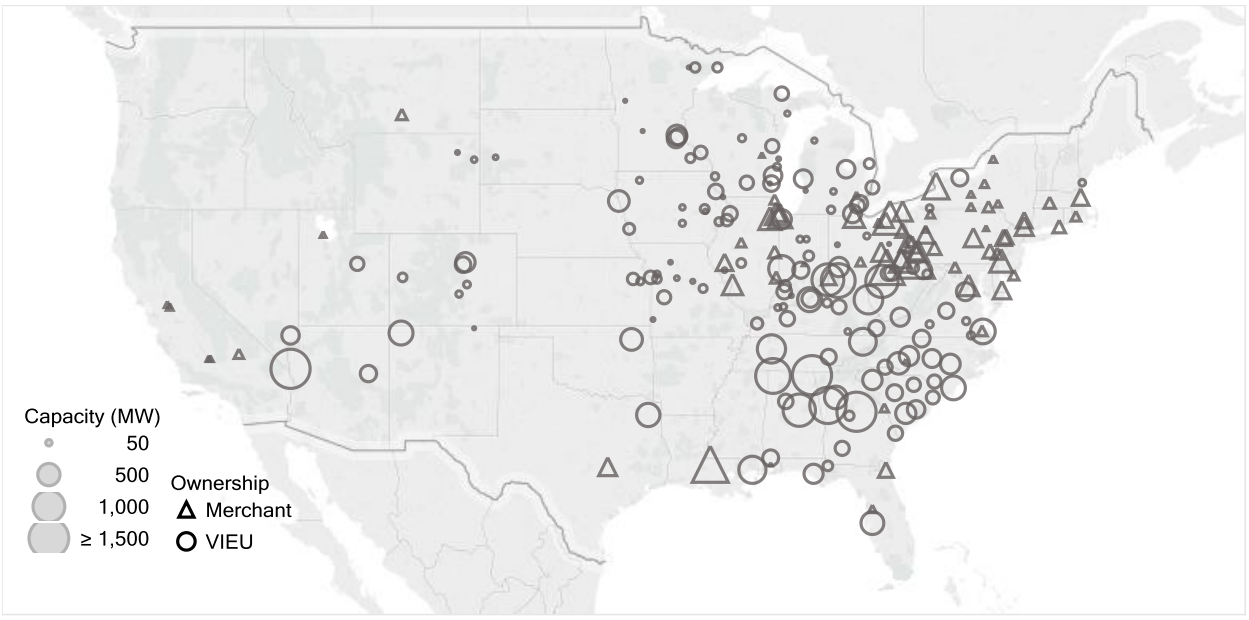


EIA reports that:

> Coal-fired electricity generators accounted for 25% of operating electricity generating capacity in the United States and generated about 30% of U.S. electricity in 2016. Most coal-fired capacity (88%) was built between 1950 and 1990, and the capacity-weighted average age of operating coal facilities is 39 years.[32]

More than 90 percent of the coal consumed in the United States is used for power generation.[33] Coal energy production peaked in 2007 and has been declining since. No new coal plants have been built for domestic utility electricity production since 2014[34] because new coal plants are more expensive to build and operate than natural gas-fired plants.[35] Further, as Figure 3.7 shows, coal retirements span many regions.

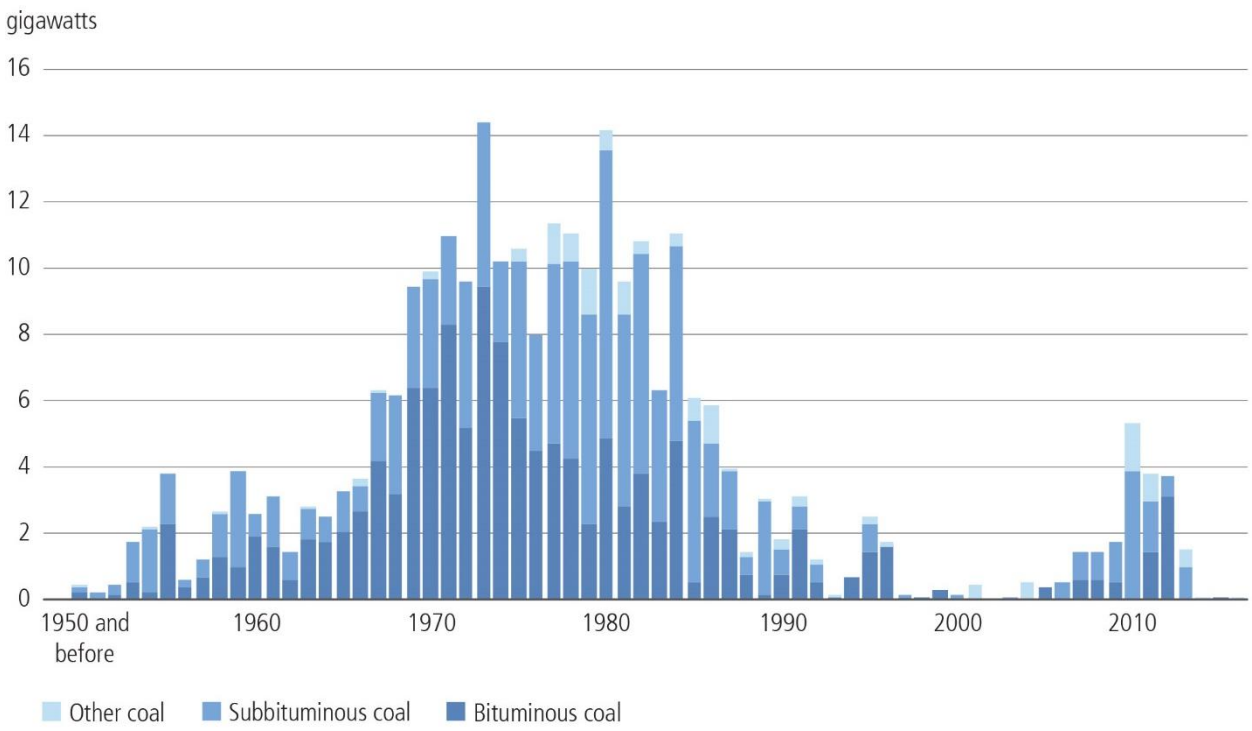
Figure 3.7. Location of Coal Retirements, 2002–2016[36]



Between 2002 and 2016, 531 coal generating units representing approximately 59,000 MW of generation capacity retired from the U.S. generation fleet.

The age of coal plants is an important factor. As Figure 3.8 shows, the vast majority of coal-fired capacity was built before 1990, with the average of the fleet built in the mid to late 1970s.[37] According to the Congressional Research Service, the service life of coal-fired generators reportedly "averages between 35 and 50 years, and varies according to boiler type, maintenance practices, and the type of coal burned, among other factors."[38]

Figure 3.8. U.S. Utility-Scale Coal-Fired Electric Generating Capacity Additions by Coal Type and Initial Operating Year[39] [40]



Between 2002 and 2016, 531 coal generating units representing approximately 59,000 MW of generation capacity retired from the U.S. generation fleet.[41] EIA reported that coal-fired power plants made up more than 80 percent of the 18,000 MW of electric generating capacity that retired in 2015, and that the retiring units "tended to be older and smaller in capacity than the coal generation fleet that continues to operate."[42]

An analysis of coal plant and other data indicates several important trends and attributes:

- About 70 percent of the plants that retired between 2010 and 2016 had a capacity factor of less than 50 percent in the year prior to retirement, and about half of the future planned retirements operated below a 50 percent capacity factor in 2016.[43]
- While none of the units that retired between 2010 and 2016 had significant SO_2 control equipment installed, more than half of the future announced retirements have SO_2 control.
- The average size of planned retirements (380 MW) exceeds the average size of recent retirements (218 MW), indicating that future retirements will be generally larger than previous ones.[44]

- Retired plants are older than the remaining fleet. The coal units that retired in 2015 were mainly built between 1950 and 1970, and the average age of those retired units was 54 years. The remaining coal fleet is relatively younger, with an average age of 38 years in 2016.[45]

In summary, until quite recently, the coal plants that have retired were smaller, older, had higher heat rates, and therefore were dispatched less often and ran at lower capacity factors. Most of the earliest coal retirements were merchant-owned units in the Northeast and Midwest that were more exposed to competition from other generators and fuel types, while VIEU-owned plants in the Southeast and elsewhere experienced a longer period of protection from low market prices.

Workforce Impacts of Coal Plant Retirements and Shifts in Coal Production

Falling demand for coal due to coal plant retirements and capacity factor reductions, a regional shift in coal production, and automation in mining have led to a reduction in coal production jobs. Between 2011 and September 2016, increased mechanization and a shift to western coal resulted in a loss of 36,000 coal mining jobs, of which nearly 90 percent were in Appalachia.[46] As shown in Table 3-1, more than 80 percent of the coal jobs in the United States support electricity production.[47] The oil and gas extraction sector is not subdivided and includes many non-power uses. About 35 percent of the natural gas and roughly one percent of petroleum jobs in the United States support electricity production.[48]

Growth in some energy sectors, such as solar energy deployment, supported new jobs, but they vary regionally and often do not correlate well with concurrent job losses in sectors such as coal mining or power plant operations. Job growth in other energy sectors and regions cannot sufficiently offset job losses in the coal sector without adequate training, salary adjustments, or transition assistance.

Table 3-1. Direct Employment and Income in Industries Related to Electric Power Supply, 2016[49]

Industry Sector/Subsector	Jobs	Percent Related to Electricity Industry	Average Annual Income
Electric power generation	191,000	100%	$113,000
Electric power transmission and distribution	292,000	100%	$99,000
Electric power total	483,000	100%	$104,000
Coal mining[y]	55,000	~80%	$82,000
Oil and gas extraction[z]	377,000	~35% of gas, ~1% of oil	$118,000
Mining and extraction total	432,000	Unknown	$113,000

[y] Includes supporting North American Industry Classification System (NAICS) industry categories.

[z] Includes supporting NAICS industry categories.

Coal Plant Closure Considerations[50]

In September 2016, Ed Malley of *Power Magazine* noted:

> The primary recent drivers of coal plant retirement announcements include low natural gas prices and new environmental regulations—especially the Mercury and Air Toxics Standards (MATS), Clean Water Act Section 316(b), and the Coal Combustion Residuals rule. Other contributing factors include more competitive markets and a variety of regional and state-level policies involving renewables and carbon pricing.
>
> Most of the power plants being closed today were built in the 1940s to 1960s, before the Clean Air Act was passed in 1970. Many have minimal air pollution controls, use once-through cooling water, and sluice wet coal ash to ponds. Scrubbers, closed-loop cooling, and dry ash handling are current requirements, or will be phased in over the next few years. Because much of the older capacity tends to be smaller units less than 300 megawatts (MW), which are not economical to retrofit, they are therefore retired. Many closures coincided with the MATS deadlines in 2015 and 2016, at a time when natural gas prices were at historic lows.
>
> Now that the MATS deadlines have passed, additional companies are announcing closures, including Dynegy (5,000 MW) and DTE Energy (2,100 MW). Economics, renewable energy mandates, and reduced demand for electricity are driving these additional closures.
>
> Power plant closure activity began on the East and West Coasts in oil-fired plants because of the high cost of fuel. Closures are now occurring in the coal belts, the Upper Midwest, and the Southeast. There are even some coal-fired plant closures in Western states.

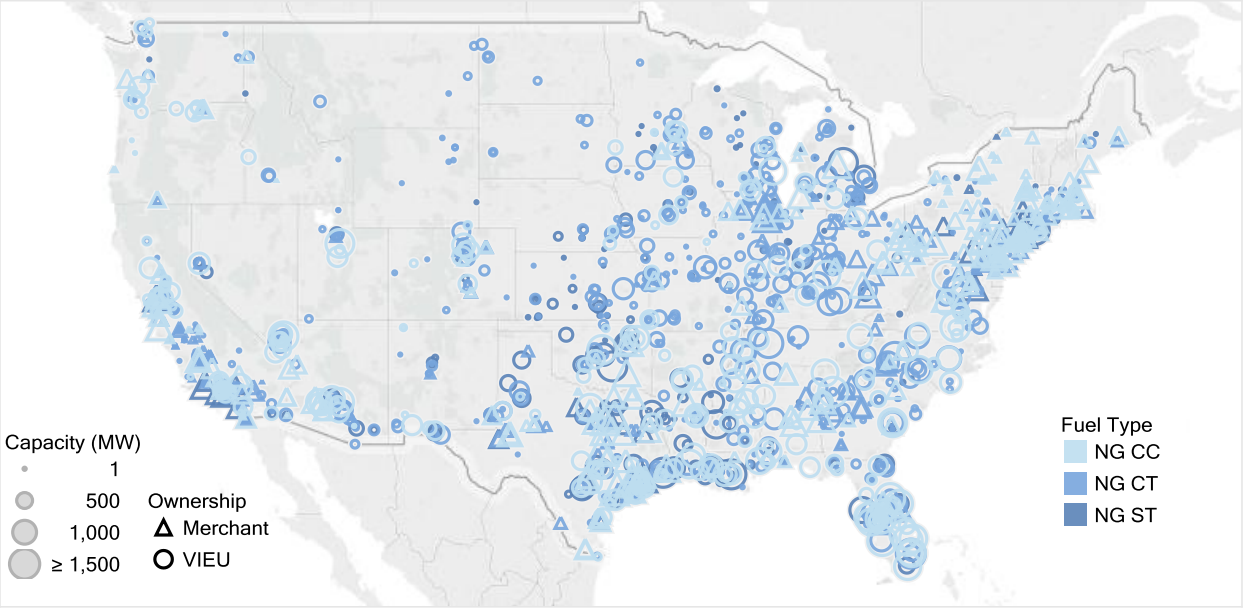
3.2 Natural Gas Plant Retirements

In recent years, the story of natural gas for electricity generation has been one of overall growth rather than decline. However, many natural gas plants have retired since 2002. Natural gas plants are located across the lower 48 states, and are concentrated around major population centers, as shown in Figure 3.9.

According to EIA:

> In 2016, natural gas-fired generators accounted for 42% of the operating electricity generating capacity in the United States. Natural gas provided 34% of total electricity generation in 2016, surpassing coal to become the leading generation source. The increase in natural gas generation since 2005 is primarily a result of the continued cost-competitiveness of natural gas relative to coal.[51]

Figure 3.9. Location of the Existing Natural Gas Fleet[52]



NGCC units accounted for 54 percent of the 447,000 MW of total U.S. natural gas-powered generator capacity in 2016. Combined-cycle generators have been a popular technology choice since the 1990s and made up a large share of the capacity added between 2000 and 2005. Some other types of natural gas-fired technology, such as combustion turbines (CTs, representing about 28 percent of total natural gas-powered generator capacity) and steam turbines (NGSTs, 17 percent), generally only run during hours when electricity demand is high.

The capacity-weighted average age of U.S. natural gas power plants is 22 years, which is less than hydro (64 years), coal (39 years), and nuclear (36 years). The improved efficiency of NGCC plants has led to them being used to a greater degree as baseload generation and increased the overall generation from natural gas. Figure 3.10 shows the initial operating years for the three types of natural gas-fired capacity additions (and their respective share of total natural gas generation in 2016).

Figure 3.10. Capacity Additions of U.S. Utility-Scale Natural Gas-Fired Electricity Generation by Technology Type and Initial Operating Year[53]

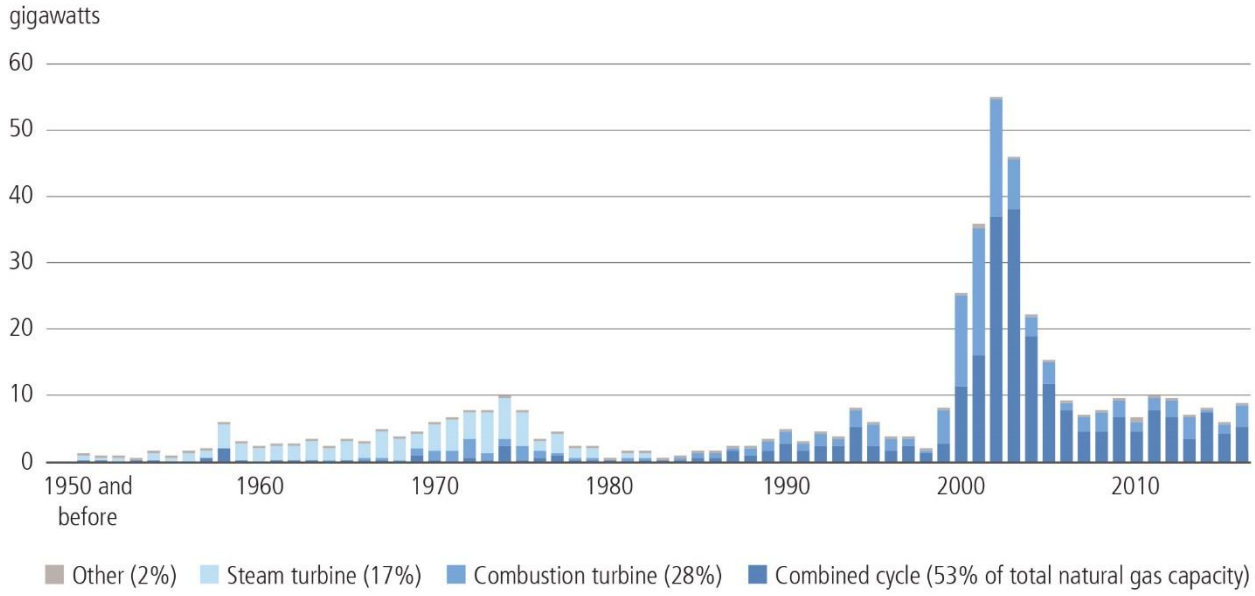
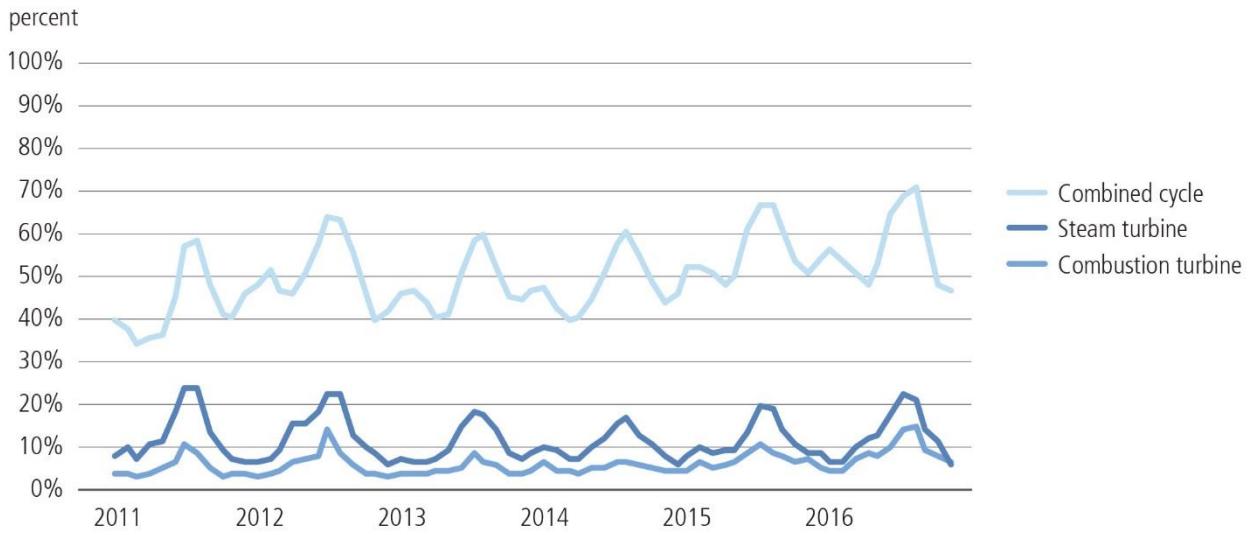


Figure 3.11 shows total natural gas-fired net generation and how the capacity factors of these plants vary by technology over the period 2011–2016. Although NGSTs were originally built principally for baseload use, since the early 2000s, they have been displaced in the dispatch merit order by more efficient NGCC plants designed for greater flexibility. As shown in Figure 3.11, NGST units operate at significantly lower capacity factors than NGCC units.

Figure 3.11. Natural Gas Fleet Capacity Factors[54]



The States of California, Texas, New York, and Florida all had more than 20,000 MW of natural gas-fired capacity at the end of 2016. The National Renewable Energy Laboratory (NREL) reports that, due to the flexibility, efficiency, and cost competitiveness of NGCC power plants, grid operators have been dispatching NGCC plants more frequently as baseload generators.[55] In consequence, the average capacity factor for all NGCC plants has grown from about 40 percent in 2008 to roughly 56 percent in 2016, surpassing that of coal.[56]

Figure 3.12. Location of Natural Gas Retirements[57]

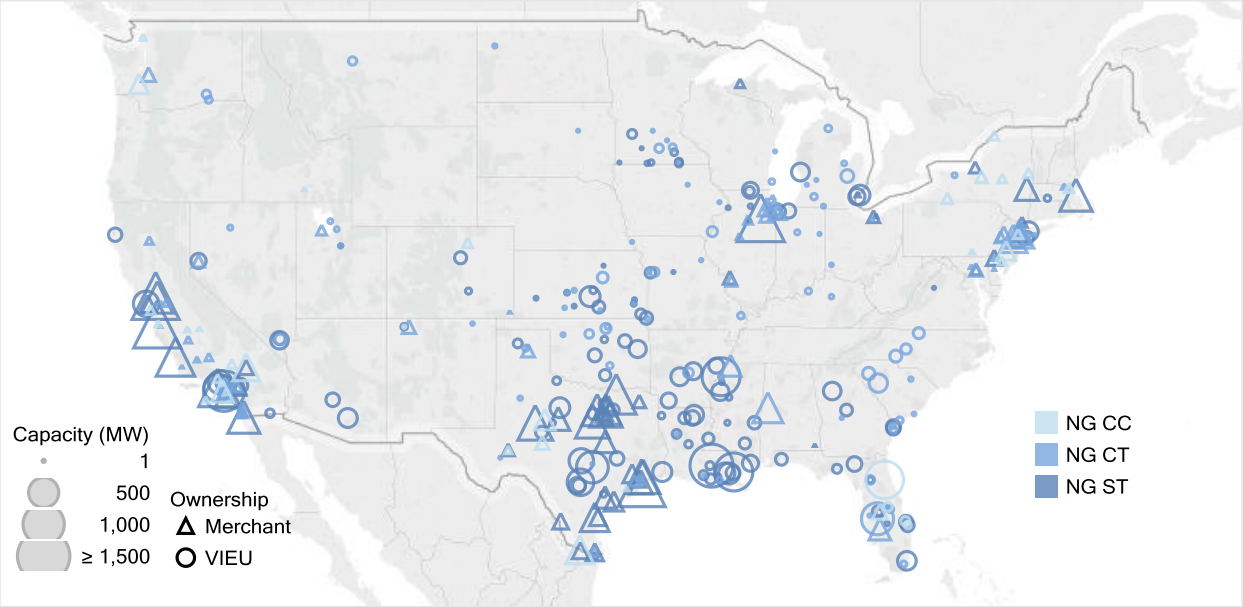
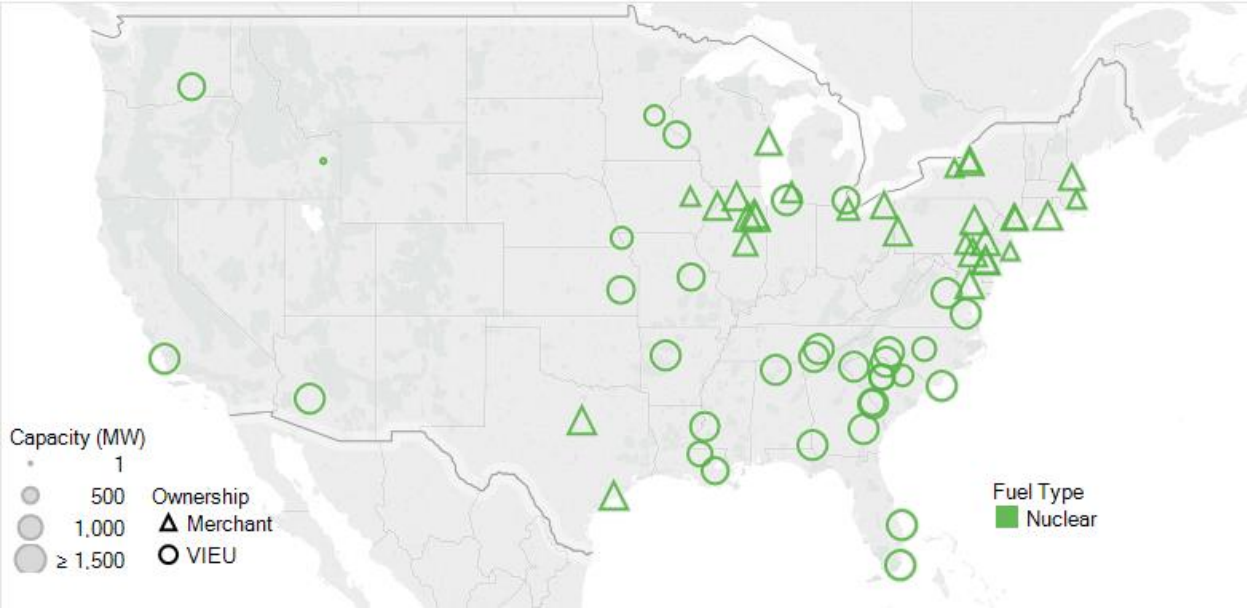


Figure 3.12 shows the retirements of natural gas plants between 2002 and 2016. The ERCOT and CAISO markets have presented difficulties for merchant natural gas (depicted as triangles above; note the concentration of merchant retirements in California and Texas). EIA reported in 2011 that between 2000 and 2010, 33,000 MW of natural gas-fired generation retired (72 percent steam turbines), with an average age at retirement of 48 years and with significantly higher heat rates than the average NGCC.[58]

3.3 Nuclear Plant Retirements

The current operating nuclear power fleet consists of approximately 54,000 MW of generating capacity in regulated markets and approximately 45,000 MW in restructured electricity markets.[59] This represents nine percent of total U.S. utility-scale generation capacity in 2017 and 20 percent of U.S. electric generation in 2016. EIA reports that nuclear plants have higher capacity factors than any other electric generation technology, averaging more than 90 percent (nearly full capacity, full time) over the past five years. The plants refuel every 18 to 24 months.[60]

Figure 3.13. Location of the Existing Nuclear Fleet[61]



The first of these units went online in 1969, and the capacity-weighted average age of the nuclear fleet is 37 years old.[62] Almost all of the operating plants have received approval to conduct at least one capacity uprate; through 2016, these uprates to the existing fleet have contributed more than 7,000 MW of additional nuclear capacity.[63] In addition to capital investments for capacity uprates, nuclear owners make significant capital investments to replace aging components to qualify for license renewal, as well as a suite of additional security and safety investments to comply with new regulations following 9/11 and the Fukushima nuclear accident in 2011.

The United States has the world's largest nuclear reactor fleet. Nuclear power plants contribute about 60 percent of total U.S. emissions-free generation.[64] Located in 60 power plants, the 99 active nuclear reactors provide almost half a million jobs and contribute more than $60 billion to the U.S. GDP.[65] Nuclear energy is viewed as a key strategic asset for the United States, and continued U.S. leadership in the global nuclear energy market has important nonproliferation and safety ramifications to national security interests.[66] As noted recently by Prof. Michael Webber of the University of Texas:

> While the environmental and reliability impacts of the [nuclear plant] closures are well-understood, what many don't realize is that these closures also pose long-term risks to our national security. As the nuclear power industry declines, it discourages the development of our most important anti-proliferation asset: a bunch of smart nuclear scientists and engineers….The loss of expertise from a declining domestic nuclear workforce makes it hard for Americans to conduct the inspections that help keep the world safe from nuclear weapons.[67]

Of the 99 active nuclear units, 51 are owned by VIEUs, which rely on regulated cost-of-service ratemaking. This form of ratemaking provides a stable source of cost recovery assuming reasonably prudent operation and management by the utility. The continued operation of these units depends on decisions by their ratemaking authorities: state regulators; state governments; city councils; cooperative boards; Federal entities; and state regulatory bodies. If these plants become less competitive, authorities may decide to close nuclear units on economic grounds. Authorities can also decide to close nuclear units on grounds other than economics—for example, proximity to the New York City

metropolitan area (36 miles) has been cited as an additional concern in the continued operation of the Indian Point nuclear plant.

Twenty-eight nuclear plants are now merchant plants that were spun off by VIEUs to affiliates under state electric restructuring efforts in the early 2000s. All of these merchant nuclear units operate in centrally-organized wholesale markets. Many of the units were spun off to exploit high locational marginal prices (LMPs) in centrally-organized wholesale electricity markets in the days of high natural gas prices.[aa]

In New York and Illinois, Clean Energy Standards and associated Zero Emission Credits (ZEC) for nuclear plants are being used to help maintain the economic viability and continued operations of nuclear plants, in part to help meet the states' GHG-limiting goals. Modeled after existing RPS and Renewable Energy Certificates (REC), these ZEC payments[68] [69] have been established to direct additional funds to existing nuclear power plants that are no longer cost-competitive. Currently, only New York and Illinois have Clean Energy Standard programs, and these programs are being litigated in the courts.

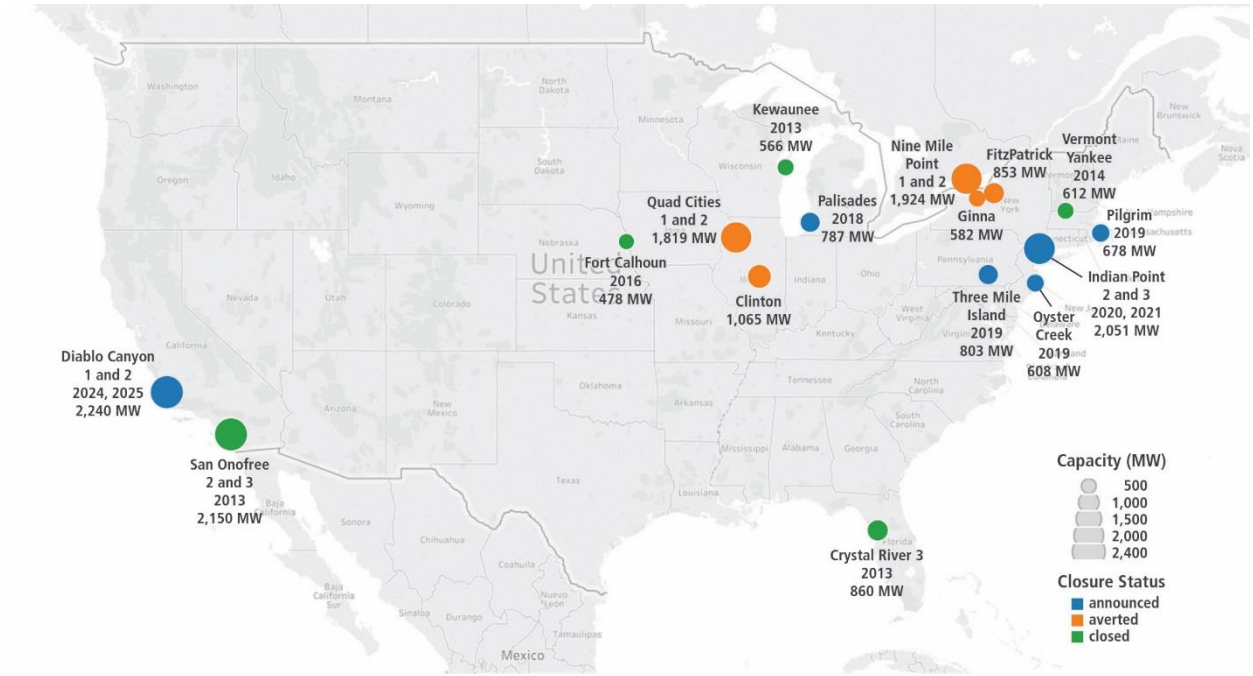
A recent Idaho National Laboratory report observes that[70]

- There is an industrywide systemic economic and financial challenge to operating nuclear power plants in centrally organized markets;
- Given the confluence of market factors in combination with market structure in centrally organized markets, a significant number of operating nuclear plants have negative cash flow positions today;
- Given current trends, these market factors are unlikely to change significantly over the next five years;
- Retirement of nuclear plants before their operating licenses expire is caused primarily by lower revenues as opposed to higher operating costs, as wholesale electricity prices have precipitously fallen over the last several years;
- The magnitude of the gap between operating revenues and operating costs is in the range of $5–$15 per megawatt-hour (MWh). For a 1,000 MW nuclear unit, approximately every $5/MWh of gap represents about $40 million in annual negative cash flow;
- Without action to enhance revenue (e.g., New York ZEC payments), more nuclear plants will face retirements before the end of their operating license in the future.[71]

Figure 3.14 shows the nuclear reactors that have announced retirement, those that have closed, and those whose closure has been averted by state action. Between 2002 and 2016, 4,666 MW of nuclear generating capacity was announced for retirement, or approximately 4.7 percent of the U.S. total.[72]

[aa] Profits from high wholesale prices are not available to utility cost-of-service regulated units because their revenues are set by state regulators to recover operating costs and provide a target return on invested capital.

Figure 3.14. Location of Nuclear Power Plant Retirements: Closed, Announced, and Averted[73]



As shown in Table 3-2, another eight reactors representing 7,167 MW of nuclear capacity (7.2 percent of U.S. nuclear capacity and 0.6 percent of total U.S. generating capacity[74]) have announced retirement plans since 2016. This does not include seven reactors that averted early retirement through state action.

Table 3-2. Nuclear Plant Retirements, Announced Closures, and Plants Averted by State Action[75] [76] [77]

Closure Year	Reactor	Capacity (MW)	Capacity Factor (2014-2016)	State	Market Type	License Expiration (Licensed Lifetime)	Reason
2013	**Crystal River 3**	860	NA	FL	Vertically Integrated	2016 (40)	failed steam generator replacement
	San Onofre 2 & 3	2,150	NA	CA	Restructured (CAISO) (rate regulated)	2023 / 2024 (40)	failed steam generator replacement
	Kewaunee	566	NA	WI	Restructured (MISO)	2033 (60)	market conditions
2014	**Vermont Yankee**	612	90 (2013 - 2014)	VT	Restructured (ISO-NE)	2032 (60)	market conditions
2016	**Fort Calhoun**	478	62 (2013 - 2015)	NE	Vertically Integrated	2033 (60)	market conditions
2018	**Palisades**	787	93	MI	Restructured (MISO)	2031 (60)	market conditions (despite being under PPA through 2022)
2019	**Pilgrim**	678	91	MA	Restructured (ISO-NE)	2032 (60)	market conditions
	Oyster Creek	608	92	NJ	Restructured (PJM)	2029 (60)	state policy / avoid large capital costs associated with building a cooling tower
	Three Mile Island 1	803	99	PA	Restructured (PJM)	2034 (60)	market conditions
2020-2021	**Indian Point 2 & 3**	2,051	86 / 94	NY	Restructured (NYISO)	2013 / 2015 (40)	state policy
2024-2025	**Diablo Canyon 1 & 2**	2,240	92 / 92	CA	Restructured (CAISO) (rate regulated)	2024 / 2025 (40)	state policy / market conditions
Included in State CES	**FitzPatrick**	853	86	NY	Restructured (NYISO)	2034 (60)	market conditions
	Ginna	582	95	NY	Restructured (NYISO)	2029 (60)	market conditions
	Nine Mile Point 1 & 2	1,924	92 / 93	NY	Restructured (NYISO)	2029 / 2046 (60)	market conditions
	Clinton	1,065	95	IL	Restructured (MISO)	2026 (40)	market conditions
	Quad Cities 1 & 2	1,819	100 / 95	IL	Restructured (PJM)	2032 (60)	market conditions

As Table 3-2 shows, Indian Point is the only announced closure that lists state policy as the sole reason for retirement. 12 of the 16 plant closure announcements refer to unfavorable market conditions as the driver for plant retirement. Four of the five nuclear power plants (six reactors) that have shut down since 2013 were single-unit plants. Of the 11 nuclear power plants (15 reactors) that have announced

intentions to close—including the five plants (seven reactors) in New York and Illinois that will remain open as a result of state action—four are dual-unit plants and seven are single-unit plants.

Table 3-3 shows the range of nuclear plant average costs in 2016 (in $/MWh). The data indicates that single-unit plants are more costly than multi-unit plants, and that operators who own only one nuclear plant have higher costs than those who own a fleet of plants. This is largely because some operating costs, such as security, do not scale linearly with plant size. As a result, single-unit or smaller plants are more expensive, and thus more likely to be retired prior to the end of their license terms.

Table 3-3. Average Nuclear Costs by Plant Size and Operator Type, 2016[78]

2016 Cost Summary ($/MWh)

Category	Number of Plants/Sites	Fuel	Capital	Operating	Total Operating (Fuel + Operating)	Total Generation (Fuel+Capital+ Operating)
All U.S.	60*	6.76	6.82	20.42	27.17	34.00
Plant Size						
Single Unit	25	6.77	8.37	25.83	32.60	40.97
Multi Unit	35	6.75	6.34	18.75	25.50	31.85
Operator						
Single	12	7.18	8.51	21.05	28.23	36.74
Fleet	48	6.63	6.33	20.24	26.87	33.20

*Costs exclude shutdown plants.

A nuclear plant fully exposed to low wholesale energy prices can earn additional revenues in three other ways: it may receive capacity payments if it is located in a centrally-organized market with a capacity payment scheme (New York, New England, MISO, and PJM), it can earn revenues for providing reliability products such as frequency response,[bb] or it may receive ZEC or similar subsidy payments from its host state.

If a nuclear plant is owned by a VIEU, its regulators may allow it to continue collecting capital recovery from its ratepayers even though the utility is effectively paying more to run the nuclear unit than it would cost to buy the same energy and capacity under a bilateral contract or spot market purchases. However, as long as natural gas prices stay low and there is an oversupply of energy in many hours, the typical nuclear plant may not be profitable. Bloomberg New Energy Finance estimates that 34 of the Nation's 60 nuclear plants are losing money.[79]

Not all nuclear power plants close due to unfavorable economics alone. For example, Pacific Gas and Electric (PG&E) has decided to shut down its dual-unit Diablo canyon plant in California due to several factors, including changes in state policy (California is moving to 50 percent RPS by 2040), new environmental regulations (replace once-through cooling system at an estimated cost of $8–$12 billion), local opposition to the NRC relicensing extension application, and uncertainty about future loads to be

[bb] See Section 4.1.1 for the technical definition of frequency.

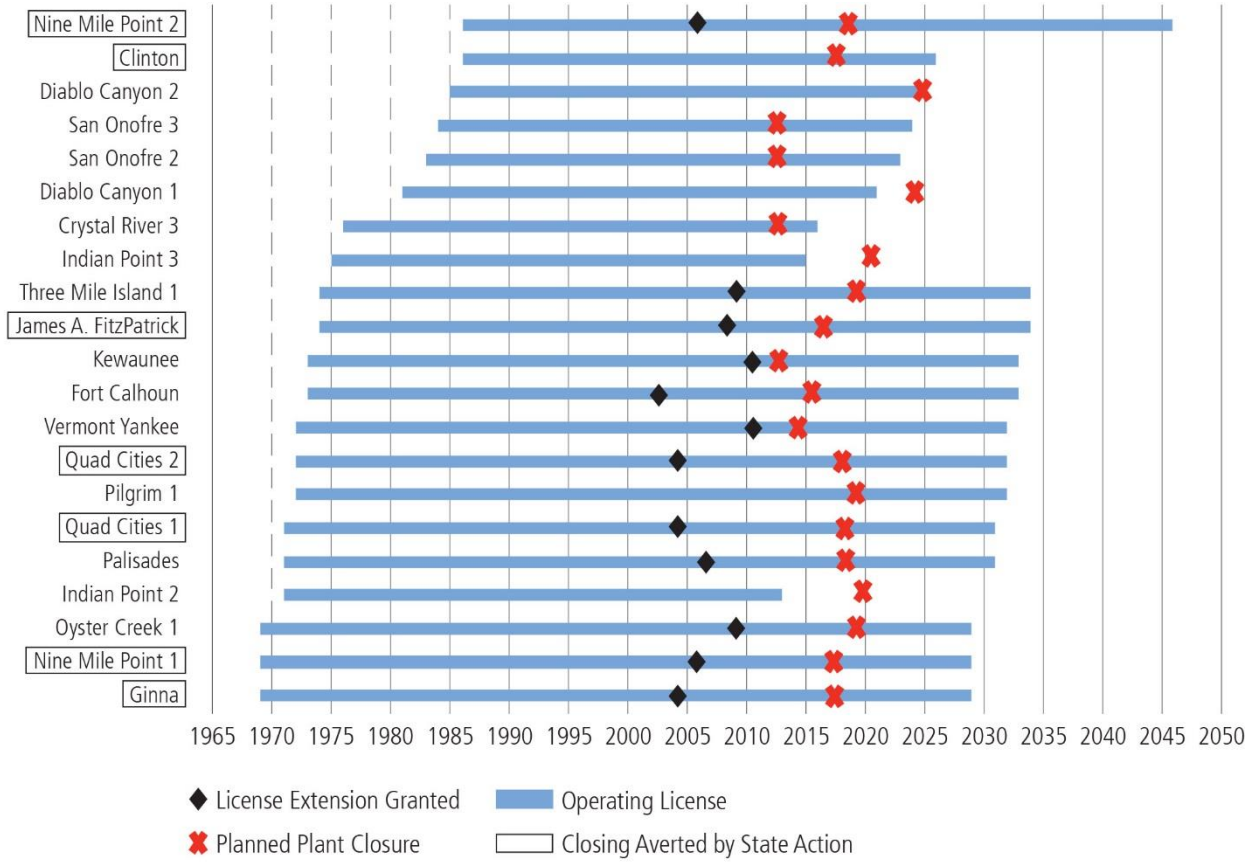
served by the regulated utility (specifically, community choice aggregation, which allows for third-party retail suppliers).

The NRC's nuclear relicensing program is another factor affecting the future of U.S. nuclear power generation. The NRC issues initial reactor operating licenses covering a 40-year term, but those licenses have been routinely extended. Of the 99 operating nuclear reactors in the United States, 84 have been approved to operate for 60 years, while another nine are currently under review.[80] However, based on the current and potential license extensions to 60 years, only three units (Comanche Peak Unit 2 and Watts Bar Units 1 and 2) will still be operating after 2050, unless subsequent license extensions—out to 80 years—are submitted and approved. Two utilities have already announced plans to seek subsequent license renewal for two plants.[81]

Extended nuclear plant operations often entail major capital upgrades of plant equipment. According to DOE's Light Water Reactor Sustainability Program, the required capital costs for equipment upgrades drive the total cost for extension; these costs vary by plant. DOE estimates that it requires $500 million to $1 billion per plant of additional capital expenditures to operate a plant for an additional 20 years.[82] These routine maintenance and equipment replacements would be required in this time frame regardless of the licensing process.[83]

Figure 3.15 shows a comparison of license duration to planned closure date. As depicted, most decisions to retire have come well before the expiration of the plant's license. A few of the plants shown in the figure (indicated by a box around the plant name) were able to avert closure as a result of state actions.

Figure 3.15. Nuclear Plant Retirements Compared to NRC Plant Operating License Terms[84] [85] [86]



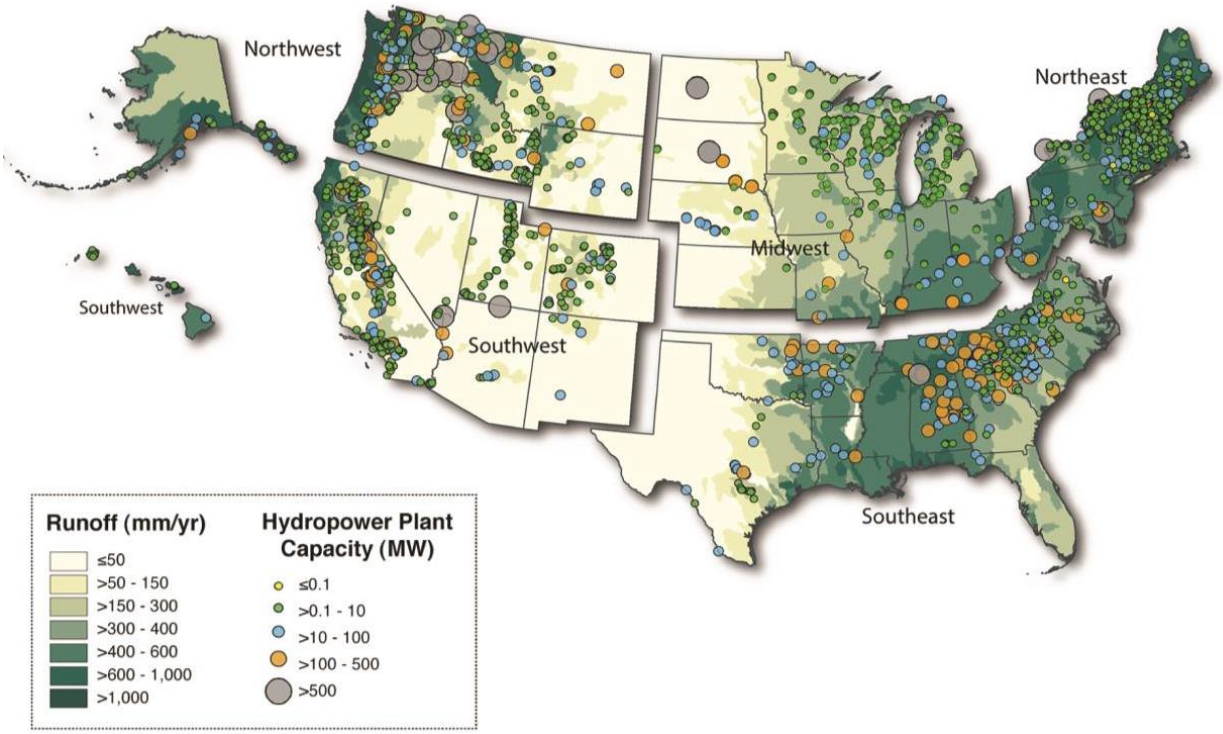
3.4 Hydropower Retirements and Repowering

In 2015, the U.S. hydropower fleet included 2,198 active power generation plants with a total capacity of 79,600 MW and 42 pumped-storage hydropower plants totaling 21,600 MW.[87] As of 2016, hydropower accounted for more than six percent of net U.S. power sector electricity generation, nearly nine percent of U.S. electric generating capacity, and 97 percent of U.S. utility-scale electrical storage capacity.[88] Hydropower is currently the largest source of renewable generation, providing nearly 44 percent of all U.S. renewable energy in 2016.[89] [90]

Half of U.S. hydro capacity is located in the States of Washington, California, and Oregon. The hydropower fleet is the oldest in the U.S. -- as stated in QER 1.2, "About half the U.S. hydroelectric fleet is over 50 years old since many large dams were built between the 1940s and 1960s,"[91] and the average hydroelectric facility has been operating for 64 years. However, with routine maintenance and refurbishment of turbines and electrical equipment, the expected life of a hydropower facility is likely to be 100 years or more.[92]

Hydropower is a varied resource. Forty-eight states (see Figure 3.16) have hydropower facilities, led by California, Oregon, and Washington. Ownership of hydropower plants is highly diverse, split across a wide range of private and public entities. Approximately 50 percent of hydropower capacity is owned by the Federal Government—the three main Federal agencies authorized by Congress to own and operate hydropower plants are the U.S. Army Corps of Engineers, the Bureau of Reclamation, and the Tennessee Valley Authority. Other public ownership includes public utility districts, irrigation districts, states, and rural cooperatives, whose hydropower resources consist of about 24 percent of the total installed capacity. Private owners—including VIEUs, merchant power producers, and industrial companies—control the remaining 25 percent of total installed capacity.[93]

Figure 3.16. Hydropower Plants in the United States by Capacity and Average Annual Runoff[94]



While some hydropower plants are operated as baseload resources, many also support the dynamic behavior of grid operations by offering a full range of ancillary services, including load following, spinning and non-spinning reserve, and voltage and frequency support. This flexibility has historically complimented other traditional forms of baseload generation, such as coal and nuclear. The majority of hydropower capacity is operated as either peaking or run-of-river. Peaking plants shift or delay water releases used for generation to higher value times of the day, contingent on a project's storage capability and the regulatory requirements governing its operation. While peaking plants have usable storage from a project's reservoir, run-of-river facilities have little to no ability to store water, and generation only changes based on the natural variability of flows, though even these types of facilities are capable of providing a number of ERS. In some regions, hydropower assets have been operated in more flexible modes in recent years as VRE penetration increases.[95]

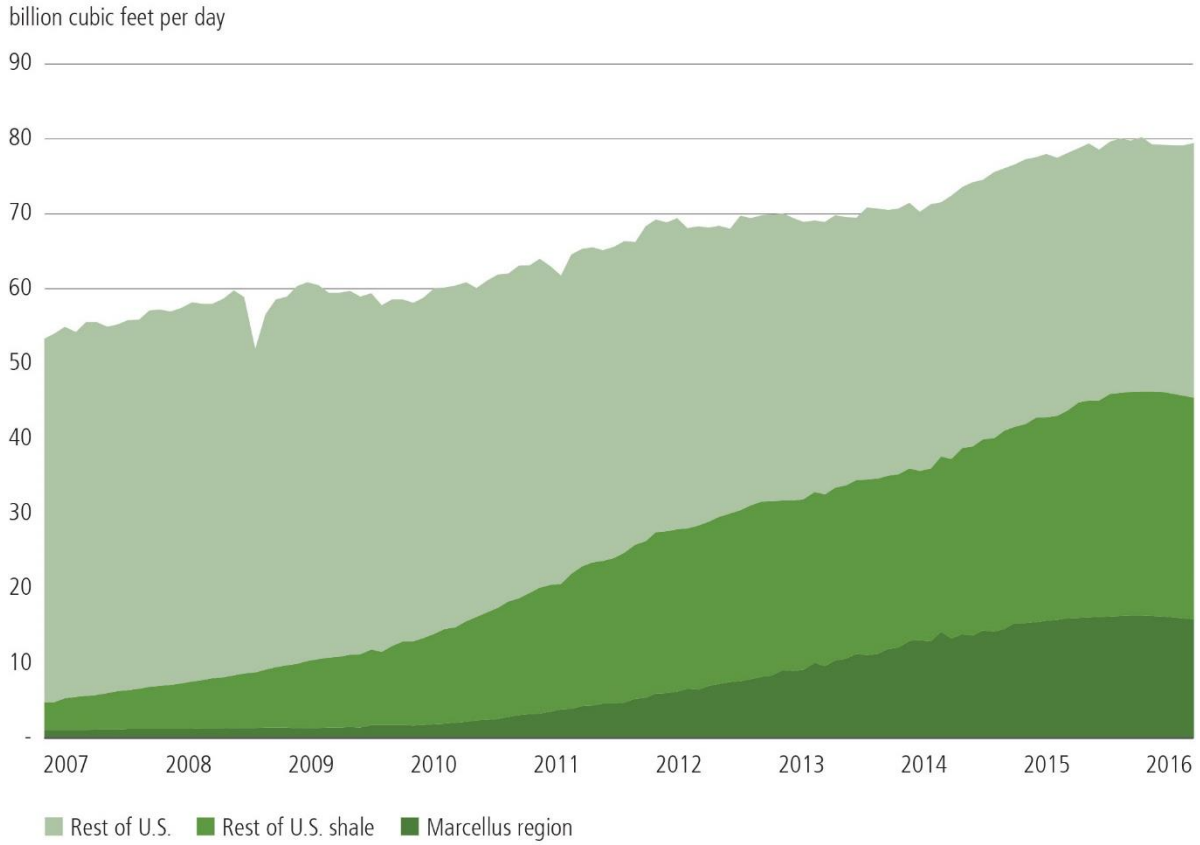
At the beginning of 2011, hydropower plants comprised 24 of the 25 oldest operating power facilities in the United States, with 72 percent of facilities older than 60 years.[96] However, significant capital investment toward modernizing and upgrading the existing fleet is consistently taking place to maintain reliability and, at times, uprate the capacity of existing facilities. From 2007 to 2016, the industry invested at least $8.7 billion in refurbishments, replacements, and upgrades to hydropower plants at 143 hydropower facilities, including $1.2 billion and 34 plants in 2016 alone.[97] This often includes equipment upgrades, turbine efficiency improvements, and modifications that ensure environmental protection and mitigation as part of relicensing terms. Most of the recent hydropower capacity additions in the United States have come from unit upgrades or additions to existing projects.[98] While FERC does receive appropriations from Congress to defray operating costs, these appropriations are recovered completely through annual charges and administrative fees.[99]

EIA public reports indicate that 1,376 MW (of the total 79,985 MW of U.S. hydroelectric capacity) retired between 2002 and 2017—in most cases as part of repowering projects in which the retired turbine generators were replaced with new equipment. Fifty-two relatively small-scale hydroelectric generators representing 283 MW of generation capacity were retired without replacement.[100]

3.5 Falling Natural Gas Prices

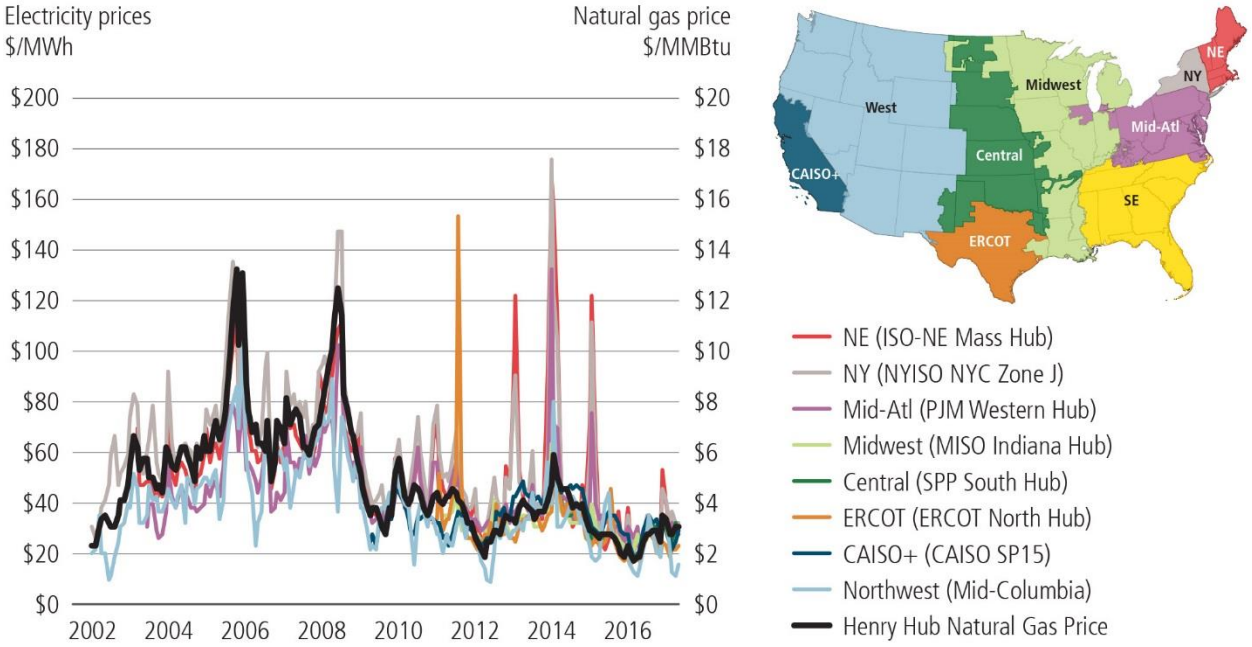
Shale gas development has significantly expanded the availability of natural gas and lowered its cost across the United States and the world.[101] Before the widespread use of horizontal drilling techniques in the past decade, U.S. natural gas prices averaged more than $7 per million British thermal unit (MMBtu) between 2003 and 2008, and approached $14/MMBtu in several short periods (including in 2005 after Hurricanes Katrina and Rita reduced production and delivery from Gulf of Mexico sources).[102] Hydraulic fracturing practices spread and made previously inaccessible gas sources economic, causing natural gas prices to fall, averaging less than $3.20/MMBtu between 2012 and 2016.[103]

Figure 3.17. Conventional and Shale Natural Gas Production, 2007–2016[104]



Wholesale electricity prices generally tracked natural gas prices for the study period, as shown in Figure 3.18. This is likely because gas-fired mid-merit and peaker power plants have been the marginal generators following load in many hours of the day, and their short-run marginal costs are driven by natural gas prices.[105] Thus, natural gas plants and gas prices have been the largest single driver of spot electricity prices.

Figure 3.18. Wholesale Day-Ahead Electricity Prices vs. Henry Hub Natural Gas Price (Monthly Average)[106]



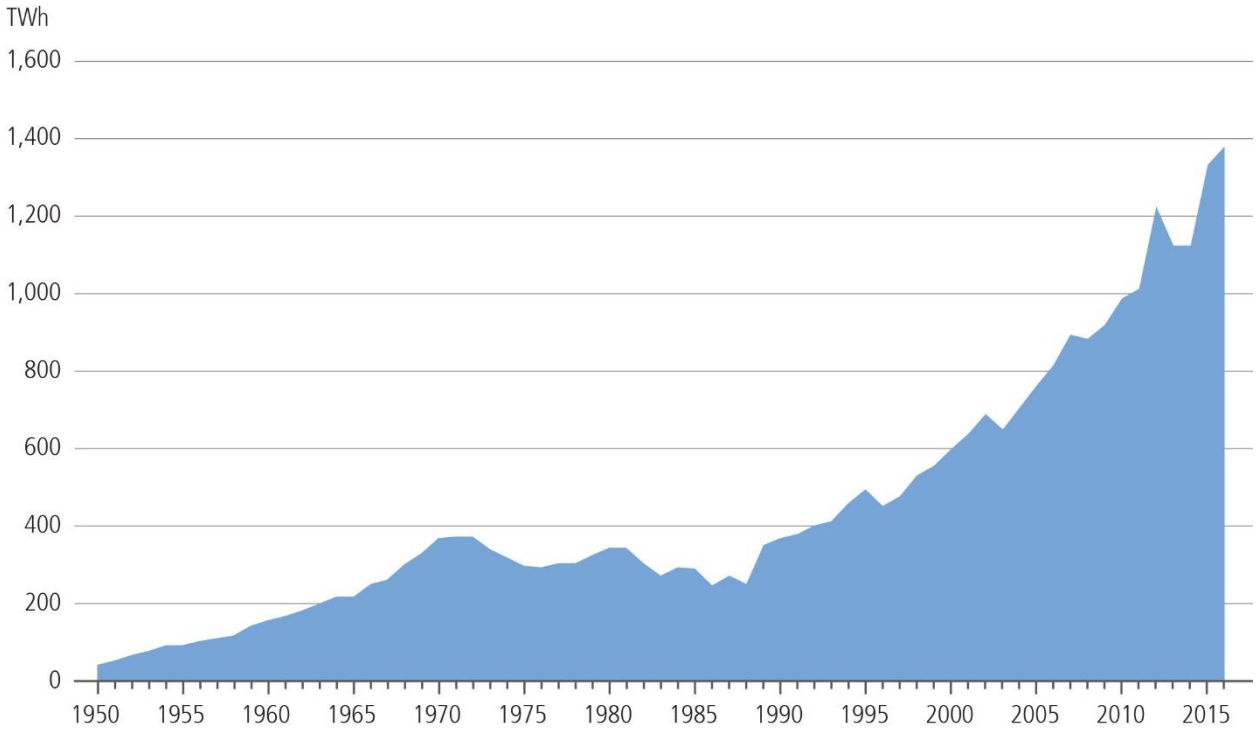
The price of natural gas is a key factor in the prices generators offer in the bid-based RTO/ISO wholesale electricity markets. It is also a factor in the prices set in bilateral power sales, including in the non-RTO/ISO regions such as the Southeast. Consequently, wholesale and bilateral transaction prices are often driven by natural gas prices across large parts of the U.S. power market.[cc] On one hand, wholesale electricity prices have become increasingly exposed to potential volatility in natural gas delivered prices. On the other hand, the Nation has realized significant economic benefits from the shale revolution—falling natural gas prices between 2007 and 2013 generated an estimated net economic benefit of $48 billion per year over this period.[107]

Natural gas-fired generation has grown nearly continuously since the late 1980s (see Figure 3.19) for several key reasons. These plants have low capital costs and are, in general, relatively less expensive than some competing technologies.[108] They are also much less land-intensive than many other types of generation, and thus often can be more easily sited in urban areas near electric demand.[109] Similarly, natural gas pipelines can be built more quickly than electric transmission lines (in most states) because they have a comparatively streamlined permitting process, which often has made it easier for a plant developer to build a new gas-fired plant near a large electric load than to build a power plant farther away and transmit its electricity to large load centers by wire.[dd]

[cc] When natural gas prices were high, this situation yielded large profits to the then lower-cost coal and nuclear power producers. However, as gas prices and therefore wholesale and bilateral contract power prices have declined, the situation has reversed, and many coal and nuclear plants have been losing money.

[dd] Interstate natural gas pipelines can often be built more quickly than transmission lines because the pipeline owners, once granted a FERC-issued certificate of public convenience and necessity, have eminent domain power under section 7(h) of the Natural Gas Act and the procedures set forth under the Federal Rules of Civil Procedure (Rule 71A). By contrast, electric transmission developers are dependent on states to grant eminent domain authorization.

Figure 3.19. Total Annual U.S. Natural Gas Generation, 1950–2016[110]



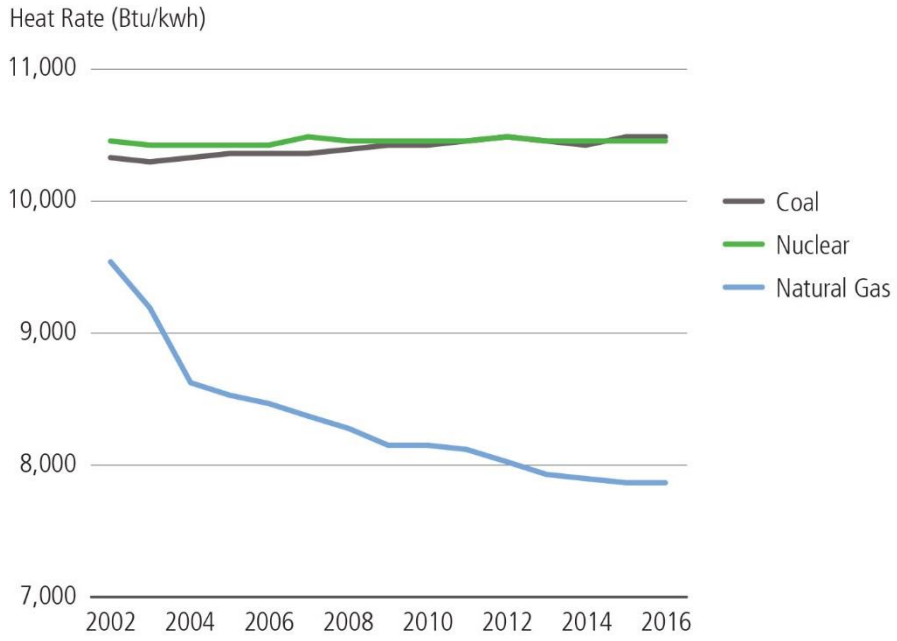
The two main types of natural gas generators (NGCCs and CTs) offer distinct operational advantages. NGCC generators are very efficient and have significantly higher capacity factors than single[111] (simple) cycle natural gas CTs, which contribute primarily to meeting peak load and may only operate for a few hours a year.[112] A CT's short start-up time and fast ramp rate make it the most responsive component for ensuring enough capacity exists to meet demand during the highest-peak demand hours of the year and help maintain grid reliability, absent affordable grid-scale storage. For this reason, CT capacity factors are usually low[ee] (generally below 10 percent).[113] CTs can go from cold start-up to 100 percent output in seven to 11 minutes; in contrast, coal-fired units ramp on the order of hours, and doing so incurs increased operations and maintenance costs.[114] NGCC ramp rates fall somewhere in between, and some NGCC units can ramp to full-rated power in less than 30 minutes.[115] This flexibility makes NGCCs and CTs useful in complementing VRE because their flexibility allows these plants to match changes in solar or wind output.

Until recently, most NGCC units were used for intermediate and peak loads rather than baseload. However, because natural gas prices have been low for a sustained period, and because NGCC plants retain some of the flexible characteristics of CTs and operate at a higher efficiency and lower cost, these units often are now used for baseload power. As a result, some coal plants have been pushed higher on the merit order, which reduces their average capacity factors, negatively impacts their economics, and can ultimately lead to retirements.

[ee] Some states rely on CTs more regularly than other locations; most notably, Texas, Louisiana, Wyoming, New Hampshire, Maine, and Rhode Island all have CT capacity factors greater than 20 percent. https://energy.gov/epsa/downloads/electricity-generation-baseline-report.

On top of low fuel prices, natural gas-fired power plants have become more fuel efficient over the study period. Figure 3.20 shows how the fuel energy usage per unit of electricity generation of the fleet of generators has changed from 2002 to 2016 for each fuel type. The natural gas fleet has become increasingly efficient (i.e., achieved a lower heat rate) as old steam electric plants have retired and many new, highly efficient NGCC plants have been built and operated at high utilization rates.[116]

Figure 3.20. Heat Rates for Coal, Nuclear, and Natural Gas, 2002–2016[117]



3.6 Environmental Regulations

A suite of environmental regulations affecting the electricity generation sector had implementation deadlines between 2011 and 2021, stemming from statutes enacted between 1970 and 1990. These regulations have had disparate effects on the costs of various power generation technologies. While the cost of environmental regulations has been significant for coal-fired power plants in particular, the evidence reviewed below indicates that regulations were not the sole cause of observed coal retirements, but were certainly a contributing factor. Following are two key takeaways:

1. Timing suggests that regulations had an impact on retirements. Of the 59,392 MW of coal-fired power plants that retired between 2002 and 2016, approximately 48,800 MW or 82 percent of that capacity retired in the period 2012–2016, when significant environmental regulations would have affected the invest-or-retire decision. This left 270,000 MW of coal-fired capacity on the grid (down from 315,000 MW in 2002), which produced 30 percent[118] of total 2016 U.S. electricity output (down from 50 percent in 2002).
2. Many of the coal plants that retired were no longer "baseload." Due to low natural gas prices and abundant natural gas generation capacity additions, most of the coal plants that retired between 2011 and 2015 (when the environmental regulations took effect) had not been operating in their intended baseload fashion for several years.[119]

All nuclear power plants are affected by regulations pertaining to safety, security, and upgrades required for license renewal. In addition, nuclear plants are affected by the Cooling Water Intake Rule, and some announced closures have cited, among other reasons, state requirements to modify cooling water systems as a reason for retirement.[120] [121] Hydropower plants are also affected by other environmental regulations and unique licensing processes.

Table 3-4 summarizes major environmental regulations finalized after 2011 affecting coal, natural gas, and nuclear power plants.

Table 3-4. Major Environmental Regulations Related to Coal, Natural Gas, and Nuclear Generation

Name	Year Finalized[ff]	Year (s) Implemented	Authorizing Statute[gg]	Major Provisions	Generation Sources Affected
Cooling Water Intake Rule[122]	2001 (Phase 1), 2003 (revised Phase 1), 2014 (Phase II)	Phase II: 2014–2018[123]	Clean Water Act	• Promulgated under 316(b) of the Clean Water Act. New sources regulated under Phase I and existing sources regulated under Phase II. • States consider requirements for power plants on a case-by-case basis.[124] • Requires controls to reduce mortality to fish and other aquatic organisms.	Coal Gas Nuclear
Cross-State Air Pollution Rule[125]	2011	Phase 1: 2015 Phase 2: 2017	Clean Air Act	• The Cross-State Air Pollution Rule replaced the Clean Air Interstate Rule starting on January 1, 2015, and requires states to reduce power plant emissions of SO_2 and NOx that contribute to ozone emissions and fine particle pollution in other states.[126]	Coal Gas
Steam Electric Effluent Limitations Guidelines[127]	1974; policy updates in 1977, 1978, 1980, 1982, and 2015	1982; 2015 update is stayed while EPA reviews rule	40 CFR 423	• Established limitations on the discharge of toxic and other chemical pollutants and thermal discharges from existing and new steam electric power plants, as well as pretreatment standards. • The 2015 update sets the first Federal limits on levels of toxic metals that can be discharged.	Coal Gas
New Source Review[hh]	1980; policy updates in 1996 and 2002	1980; 2002 updates under court challenge	Clean Air Act	• Affects stationary sources of air pollutants. Requires that a new or modified power plant obtain a pre-construction permit to ensure, among other things, that modern pollution control equipment is installed. • Requirements differ depending on whether or not the plant is located in an area that	Coal Gas

[ff] Dates shown here reflect the date of publication in the *Federal Register*.

[gg] For regulations only.

[hh] The New Source Review (NSR) program affects most new and modified power plants and manufacturing facilities. Determining when a facility is making a modification that triggers NSR has been a subject of debate. Attempts have been made over decades to update NSR—the latest in 2002. More information can be found at: http://www.rff.org/research/publications/epa-s-new-source-review-program-time-reform and http://www.aei.org/publication/making-sense-of-new-source-review/

				meets the requirements under the National Ambient Air Quality Standards.	
Mercury and Air Toxics Standards[128]	2012	2015–2016	Clean Air Act	• Establishes emissions limits for mercury, arsenic, acid gases, and other toxic pollutants from coal- and oil-fired power plants.[129] • Utilities had until April 2015 to comply with the standards with many plants receiving a 1-year extension.	Coal
Coal Combustion Residuals Rule[130]	2015	2015-2018[ii]	Resource Conservation and Recovery Act	• Addresses groundwater contamination risks from coal combustion residuals (i.e., "coal ash") disposal in unlined landfills and surface impoundments by establishing national standards for disposal.	Coal
Regional Haze Rule	1999; policy revisions in 2017	Revised state plans due in 2021	Clean Air Act	• Requires states to develop long-term strategies, including enforceable measures to improve visibility in 156 national parks and wilderness areas. • Aims at returning visibility to natural conditions by 2064.	Coal
Carbon Pollution Standards and Clean Power Plan[131]	2015	Under EPA review	Clean Air Act	• Carbon Pollution Standards established CO_2 emission standards for new fossil fuel-fired generators under Clean Air Act section 111(b). • The Clean Power Plan, promulgated under section 111(d) of the Clean Air Act, establishes CO_2 emission standards for existing power plants.	Coal Gas

The collective impact of this suite of regulations required owners to weigh the cost implications of a variety of compliance options for their plants, and to also look closely at whether their market prospects (expected production costs and capital needs, relative coal and natural gas fuel costs, competition from other generators, technology availability, and customer demand levels) or regulatory regime would allow recovery of those costs in future operating years. Most of these rules were litigated and delayed—the Clean Power Plan, for example, currently is stayed and ultimately may be rescinded, but uncertainty about its implementation nonetheless affected plant owners' compliance and retirement planning.

In 2011, looking at then-current energy market prospects and fuel prices, it appeared that many power plants would be affected by these environmental regulations. Fitch Ratings estimated that 51,000 MW of coal units (smaller than 200 MW each, with a capacity-weighted average age of nearly 50 years) were at risk for retirement, particularly those operating in restructured electricity markets with no recourse to regulated cost recovery.[132]

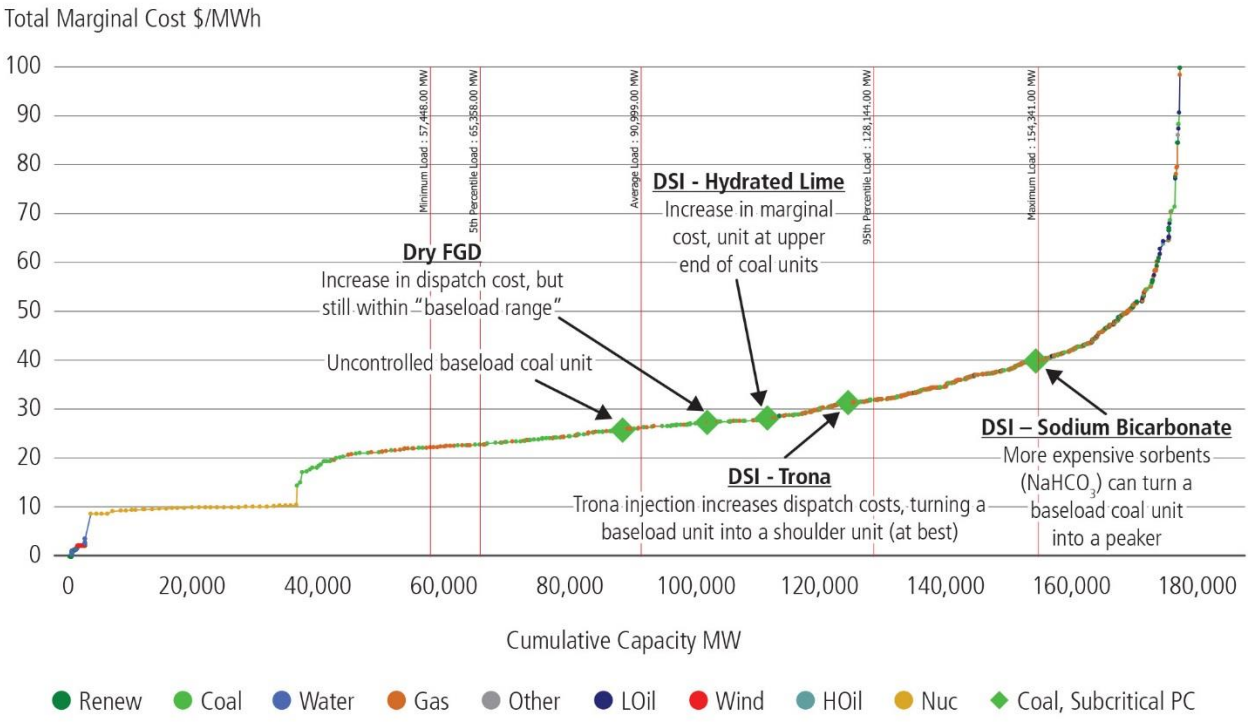
In 2011 and 2012, electric industry projections of likely regulation-induced retirements that focused on the many unknowns associated with pending environmental regulations sometimes showed a very large number of retirements. These unknowns included how stringent environment remediation requirements would be; what remediation technology and strategies might satisfy those requirements; how close together the compliance deadlines would fall; and the implications for regional reliability,

[ii] The Water Infrastructure Improvements for the Nation Act S.612, passed in December 2016, authorizes states to create their own permitting programs for coal combustion residuals disposal, subject to EPA approval. The act specifies that states may adopt alternative standards that are "at least as protective" as national standards. EPA has not yet issued guidelines or regulations by which state permitting programs can be approved.

energy production costs, and retail energy rates if too many power plants were to close rather than invest in remediation.

Environmental regulations generally increase power plant operating costs by requiring plant owners to install capital equipment that controls plant emissions. The electrical load from equipment such as SO_2 scrubbers ("parasitic load") may also reduce the plant's net generation available for sale on the grid. Increased operating costs push the compliant plant farther out on the energy supply (dispatch) curve and can cause it to be dispatched less frequently than it would have without the emissions controls, as shown in Figure 3.21 using coal as an example.

Figure 3.21. PJM Merit-Order Dispatch: Various Control Technologies[133]



This figure shows power plants separated by technology type for PJM, in "merit order", i.e., based on their marginal cost of generation, in the year 2012. The vertical lines represent various levels of load. The diamonds represent marginal costs (sum of fuel and variable operating and maintenance costs) for one subcritical pulverized coal plant with no control technology and that same plant with variations of two select pollution control technologies that reduce acid gas pollution. In principal, all the plants left of a vertical line operate at the level of demand represented by that line. (In reality, transmission constraints and reliability considerations can change that significantly.)

As a plant moves to the right on the curve it will tend to operate less due to the increase in marginal cost. Control technologies key: dry FGD = dry flue gas desulfurization; three types of DSI (hydrated lime, trona, and sodium bicarbonate) = dry sorbent injection. Another control technology not shown that is used to reduce acid gas emissions is wet flue gas desulfurization. Technology key: Renew = other renewables not including hydropower or wind power; Water = hydropower; LOil = light oil-fired power plants; HOil = heavy oil-fired power plants; Nuc = nuclear power.

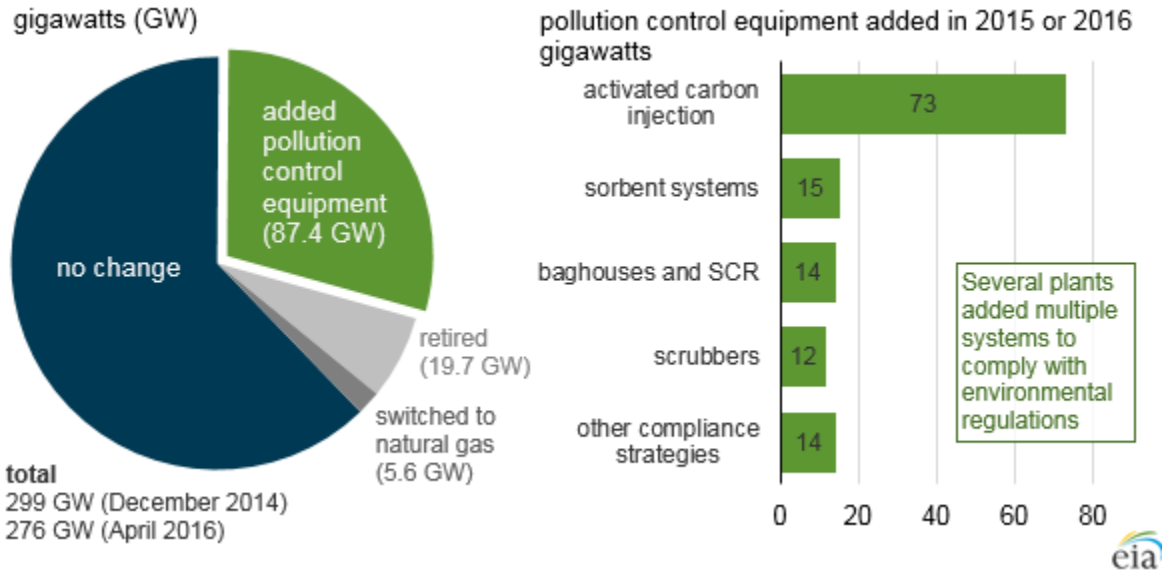
3.6.1 Coal Plants and Environmental Regulation

Existing coal-fired power plants must not only comply with all Federal requirements related to emissions and water use, wastewater treatment, and solid waste management, but also with any additional applicable state regulations.[134] Cost impacts of these regulations varied. The EPA reported that a typical coal-fueled unit with a capacity of 700 MW could incur incremental operating and maintenance costs ranging from $287 million to $351 million to install a scrubber, from $116 million to $137 million to install a selective catalytic reduction unit, and from $97 million to $114 million to install a baghouse (fabric filter). Fitch estimated the lifetime costs and reduced cash flow associated with environmental retrofits at $1,700–$1,900 per kilowatt (kW) for a 100 MW plant burning bituminous coal, as compared with a range of $1,200–$1,300/kW for a 500 MW plant.[135] These costs are on par with those of constructing a new typical (i.e., subcritical) coal plant of similar size during this same time period (averaging $1,361/kW).[136] Reported planned retirements from that time suggest that approximately 27,000 MW or 8.5 percent of 2011 coal-fired capacity was rendered uneconomic under the combination of regulatory compliance costs, little demand growth, and falling natural gas prices.[137]

The MATS rule was potentially the most expensive and immediate of the suite of pending regulations, with a compliance deadline of April 2015 (later extended to April 2016 for some plants). Further, owners of coal facilities were dealing with MATS compliance in combination with the cost of imminent additional regulations of CO_2, along with other GHGs. EIA reported that by the end of 2012, 64 percent of the U.S. coal generating capacity in the electric power sector already had the appropriate environmental control equipment (most reported using flue gas desulfurization) to comply with the MATS rule and operate past 2016; another six percent planned to add control equipment; 10 percent had announced plans to retire; and the other 20.4 percent still had to decide whether, how, and when to upgrade or retire their plants.[138]

The dominant MATS compliance strategy among coal-fired plant owners was to install activated carbon injection (Figure 3.22), which averaged a relatively modest $5.8 million per generator from 2015 to 2016. EIA estimates that "operators invested at least $6.1 billion from 2014 to 2016 to comply with MATS or other environmental regulations."[139] In its rulemaking, EPA estimated an annualized cost of $9.6 billion in 2015, declining to $7.4 billion annually in 2030.[140]

Figure 3.22. Changes in U.S. Coal Capacity, December 2014–April 2016[141]



The retrofit-or-retire decision for owners is also impacted by EPA's New Source Review (NSR) regulations that can affect owners' ability to enhance plant efficiency due to the delay, cost, and uncertainty associated with obtaining an NSR permit. The NSR permitting program requires stationary sources of air pollution—including factories, industrial boilers, and power plants—to get permits before construction starts, whether the unit is being newly built or modified.[142] This is an important concern for owners considering retrofitting an existing power plant with carbon capture equipment to reduce CO_2 emissions, or adding new components to improve operating efficiency. These upgrades could trigger the NSR requirements of the Clean Air Act because they would constitute a "physical change," or lead to a designation of the change as a "major modification," subjecting the unit to NSR permitting requirements.

The uncertainty stemming from NSR creates an unnecessary burden that discourages rather than encourages installation of CO_2 emission control equipment and investments in efficiency because of the additional expenditures and delays associated with the permitting process.[143] [144] Ironically, the uncertainty surrounding NSR requirements has led to a significant lack of investment in plant and efficiency upgrades, which would otherwise lead to more efficient power generation, benefits to grid management, and reduced environmental impacts. EPA has acknowledged these burdens and has made attempts to reform the rules to improve and streamline NSR:

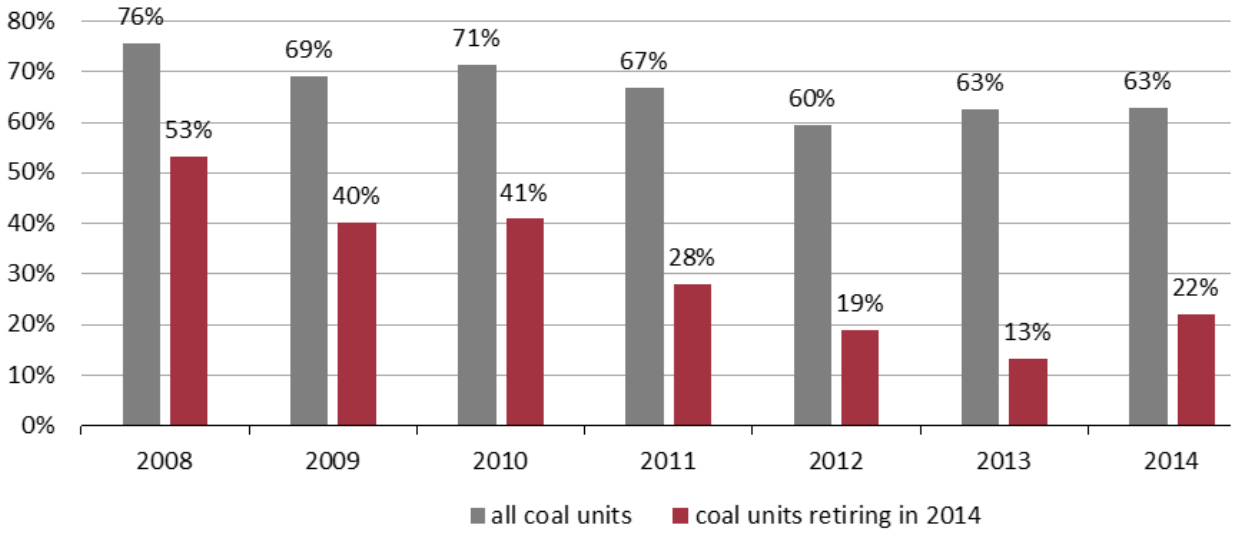
> As applied to existing power plants and refineries, EPA concludes that the NSR program has impeded or resulted in the cancellation of projects which would maintain and improve reliability, efficiency and safety of existing energy capacity. Such discouragement results in lost capacity, as well as lost opportunities to improve energy efficiency and reduce air pollution.[145]

The NSR program distinguished between "routine maintenance and repair" of existing facilities—which would be allowed—and more "substantial modification" of existing facilities, which would put the facilities over the threshold and thus require them to meet new emissions standards.

Environmentalists argued that owners of electric generation and industrial plants were building virtually new facilities from the inside out by exploiting the "routine maintenance and repair" exclusion from NSR. EPA changed its interpretation in the 1990s to a more rigorous standard, culminating in numerous enforcement-related lawsuits beginning in the late 1990s.[146]

By the late 2000s, some older coal units operating without pollution controls were no longer operating as baseload units, having operational capacity factors estimated at 47 percent to 56 percent.[147] As Figure 3.23 shows, rather than acting as baseload units at high capacity factors, these older units (with an average capacity of 109 MW) were operating at falling capacity factors. The units that retired in 2014 had an average capacity factor of 13 percent in 2013.

Figure 3.23. Average Coal Plant Capacity Factors, 2008–2014[148]



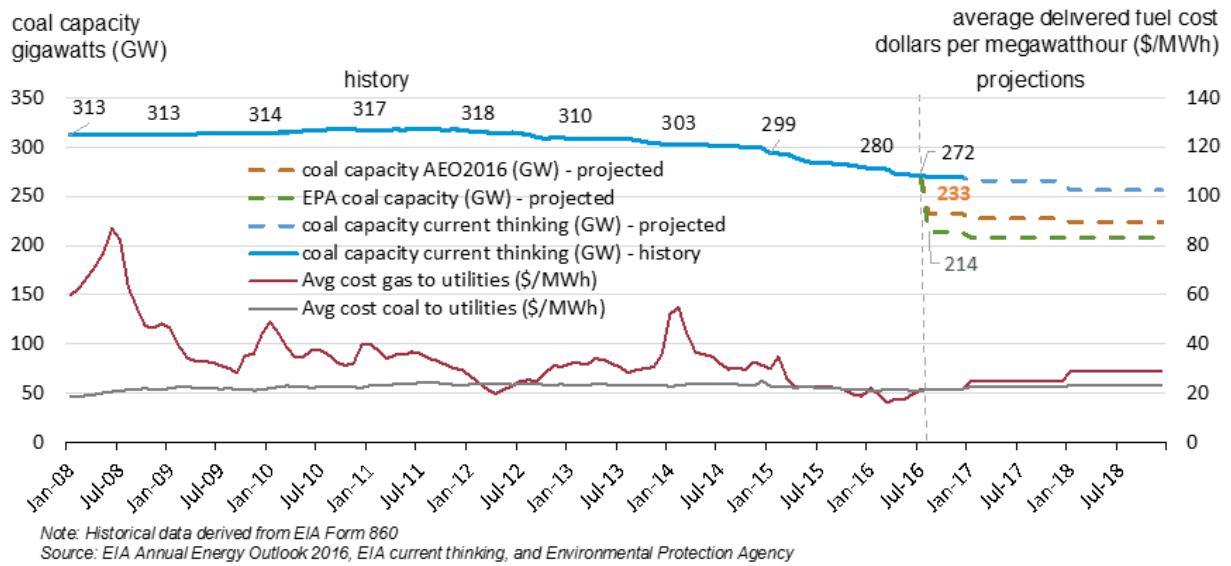
Source: EIA Form 860 and Form 923

Coal plant capacity factors generally fell from 2008 through 2014, with plants that retired in 2014 operating at much lower capacity factors than all coal plants.

Some owners delayed their retirement announcements and retrofit decisions in order to see how the regulation litigation challenges played out, in case a late court ruling made compliance unnecessary, signifying that the cost of complying with those regulations was a factor in their retirement decisions. Others delayed closing uneconomic plants to see if enough other plants retired, in hopes that the resulting shift in market dynamics and prices might render the unretired plants profitable again.[149]

Figure 3.24 shows total U.S. coal capacity from 2008 through mid-2016 and projections through mid-2018. While there was a fall in coal plant capacity in 2015 associated with the MATS compliance deadline, EIA finds that fewer coal facilities retired in 2015 and the first half of 2016 than EIA had projected ahead of the compliance deadline. Specifically, in 2015 and until the April 2016 extended MATS deadline, about 20,000 MW of coal capacity retired and another 9,000 MW of coal capacity converted to natural gas, while EIA projected 50,000 MW of retirements between 2013 and 2020, with the majority retiring in 2015 in response to MATS.[150] However, EIA's projection also included other factors that can drive retirement decisions, such as the Clean Power Plan.

Figure 3.24. Projected and Actual Coal Retirements, 2008–2018[151]



Note: Historical data derived from EIA Form 860
Source: EIA Annual Energy Outlook 2016, EIA current thinking, and Environmental Protection Agency

Fewer coal plants retired in 2015–2016 than projected.

3.6.2 Natural Gas Plants and Environmental Regulation

Because natural gas emits far less air pollution than coal-fired power plants,[152] the regulatory burden and cost to natural gas-fired power plants is much lower than for coal plants. ERCOT's December 2014 analysis estimated that the Cross-State Air Pollution Rule (CSAPR)[jj] and the Cooling Water Intake Rule would impose moderate compliance costs on natural gas-fired power plants.[153] Specifically, ERCOT estimated costs of $0.10–$2.75/MWh for CSAPR and $0.10–$0.50/MWh for the Cooling Water Intake Rule.

The large majority of natural gas plants that have retired are NGSTs, which are less efficient than the newer NGCCs.[154] From 2002 to 2016, there was a steady stream of NGST retirements, some of which may be linked to decisions about the cost effectiveness of retrofit upgrades. However, during the period 2014–2016, 23,500 MW of new natural gas capacity was added, nearly double the total natural gas capacity that was retired as part of the transition from NGST units to more efficient NGCC units.[155] NGCC plants have replaced NGST plants for baseload use and natural gas combustion turbines have been built for peak power demand.

3.6.3 Nuclear Plants and Environmental Regulation

The principal environmental regulation affecting nuclear power plants is the Cooling Water Intake Rule, which applies to all types of power plants but is most challenging for nuclear plants. A revised version of the Cooling Water Intake Rule has been in effect since 2003. The rule was promulgated to protect aquatic life. States may decide how to implement the rule, such as by requiring a nuclear (or other) plant to invest in a closed-loop cooling system to replace once-through ocean or waterway cooling. Three of the nuclear plants that have announced closures (Oyster Creek in New Jersey, Diablo Canyon in

[jj] Finalized in 2011 and effective in 2015.

California, and Indian Point in New York) have cited disputes with their respective states over cooling water rule compliance among the reasons for plant retirement. [156] [157]

The Administrative Consent Order between Exelon and New Jersey establishing Oyster Creek's 2019 retirement specifically mentions Section 316(b) of the Clean Water Act as part of the state's justification in requiring the construction of cooling towers if the plant were to operate for the full duration of its license extension.[158]

Nuclear plants are also affected by other regulatory factors and fees that are not imposed on other types of power plants. Recent examples include major safety reviews following the Fukushima Daiichi nuclear plant failures in 2011. A recent study found that the rising regulatory costs of nuclear energy—which approach $60 million per year—exceed the profit margins of many of these plants.[159]

3.6.4 Hydropower Plants and Environmental Regulation

As authorized under the Federal Power Act, FERC issues licenses to non-Federal hydropower projects, which comprise roughly 50 percent of existing U.S. hydropower capacity. The FERC regulatory framework involves numerous participants, such as Federal and state resource agencies; non-governmental organizations; state, local, and tribal entities; and the public. Because of the complexity of the regulatory processes and numerous agencies involved, hydropower licensing timelines often are cited as being among the lengthiest and costliest for energy projects in the United States. A DOE analysis looking at the development timelines of 29 projects that came online from 2005 to 2013 found that the median project took over 15 years from application to operation.[160] For wind and solar, the average permitting time is two to four years.[161]

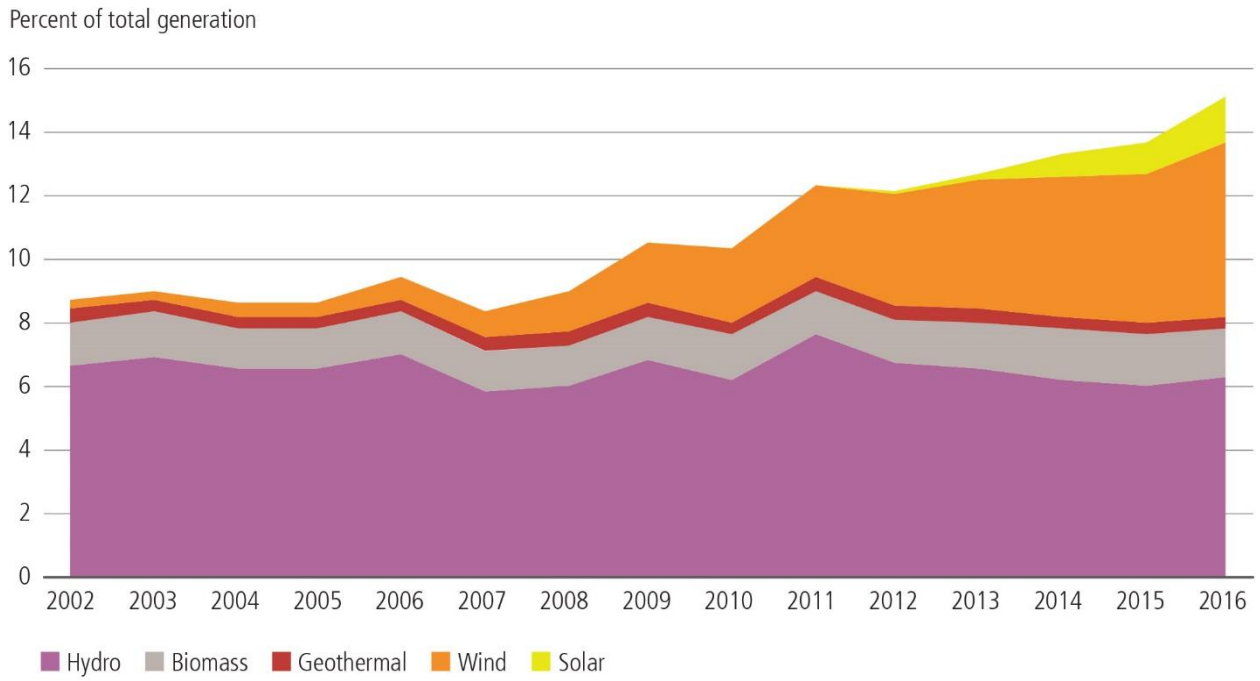
A few hydroelectric power plants have not sought relicensing due to concerns over the cost of meeting mandatory environmental requirements imposed by Federal and state resource agencies. Capital upgrade requirements can include capacity uprates (initiated by the plant owner rather than a regulator), dam safety upgrades, or environmental improvements.[162]

3.7 Growing VRE Deployment

Wind and solar PV—collectively, VRE—have constituted the vast majority of the VRE deployed in recent years. Wind first surpassed 1 percent of total U.S. generation in 2008, while total solar generation reached that threshold in 2015.[kk] Figure 3.25 shows trends in penetration—as a percentage of total generation—for wind, solar, hydroelectric, geothermal, and biomass power plants in the United States since 2001. Total end-use demand served by wind generation tripled from 1.5 percent in 2008 to 4.5 percent in 2013. Total renewable generation has now exceeded 14 percent of the U.S. total, with hydro and wind comprising the largest components.

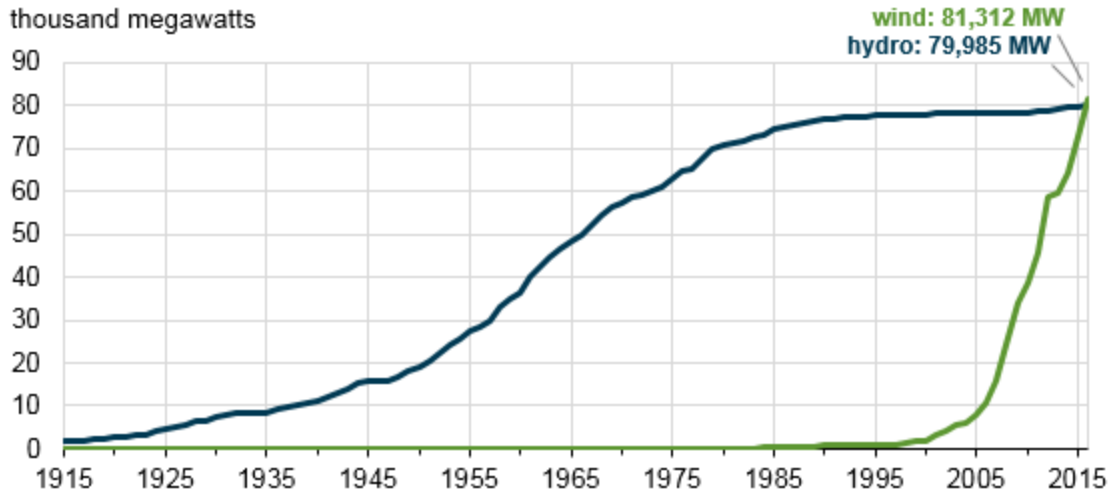
[kk] While annual variation in water availability affects conventional hydroelectric output from year to year, hydro generally has been consistent between 6 percent and 8 percent of total generation since 2001. https://www.eia.gov/totalenergy/data/monthly/pdf/sec7_6.pdf.

Figure 3.25. VRE Generation by Fuel as Percentage of Total U.S. Generation, 2002–2016[163]



At the end of 2016, U.S. installed wind capacity surpassed that of hydro for the first time (see Figure 3.26).[164] [165] However, given the hydro fleet's higher average capacity factors and the above-normal precipitation on the West Coast so far this year, hydro generation will likely once again exceed wind generation in 2017, though the gap continues to narrow.

Figure 3.26. Cumulative U.S. Utility-Scale Wind and Hydroelectric Generation Capacity, 1915–December 2016[166]



3.7.1 Technology and Policy Drivers for Deployment

The deployment of wind and solar power has been spurred by a combination of technology cost declines; state RPS; private sector sustainability goals; consumer choice; Federal and state incentives;

transmission expansion—such as the Texas Competitive Renewable Energy Zone project—to reach high-quality resource areas; and Federal and state environmental, air quality, and GHG emissions reductions policies.

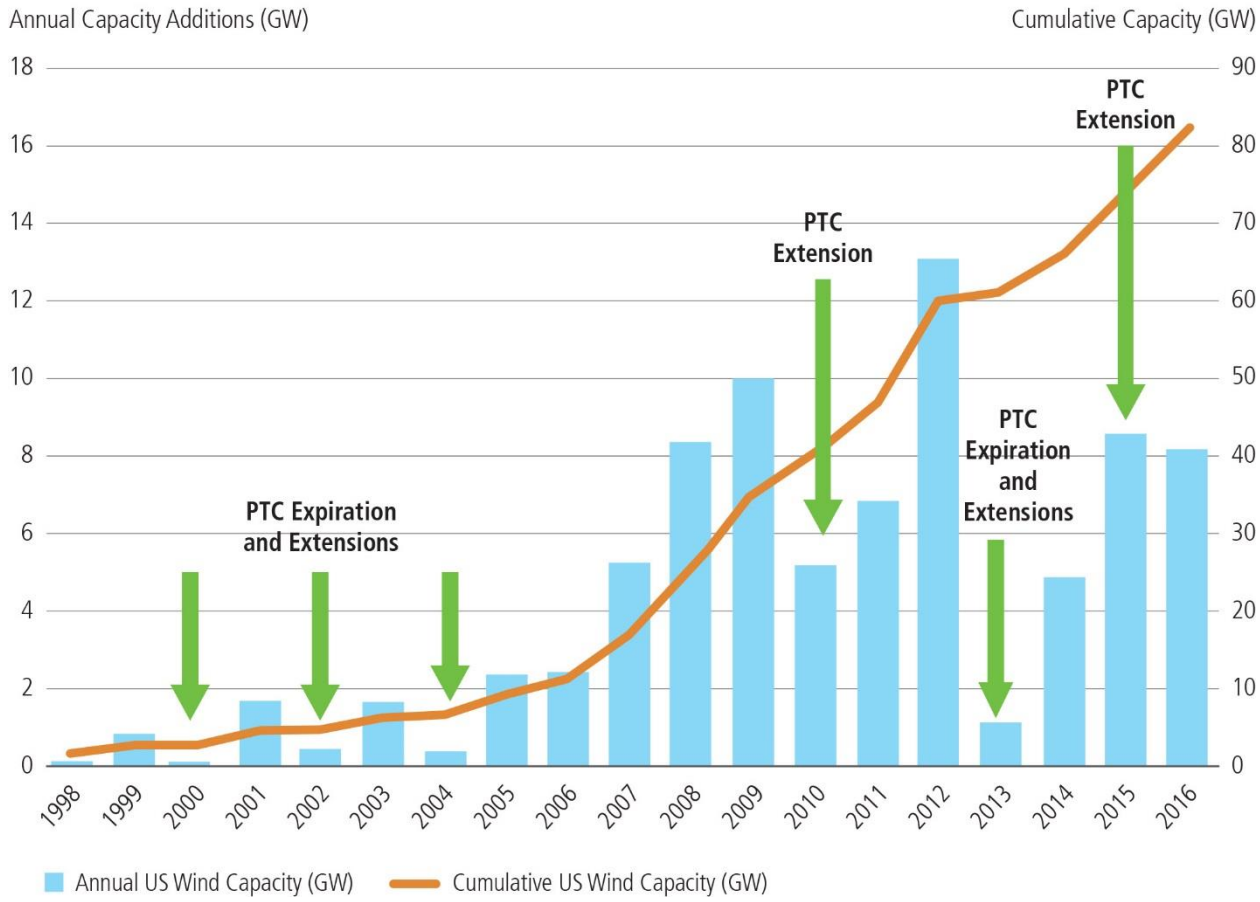
RPS—now in 29 states and the District of Columbia, covering 55 percent of total U.S. retail electricity sales—have also been substantial drivers of VRE growth, as they are associated with 60 percent of renewable generation growth since 2000.[167] Though wind has historically been the largest beneficiary of RPS policies, more RPS-driven solar than wind was added in 2015.[168] RPS also create a market for RECs. RECs represent some of the environmental attributes of renewable generation that can be bought, sold, and applied to meet certain state RPS plans, and they create an additional subsidy to renewable generation.

Technologies typically experience cost reductions as their deployment grows due to technology improvement and increasing economies of scale. Lower investment costs, in turn, spur further deployment—since 2009, solar PV installed system costs have fallen approximately 60 percent on a per kilowatt basis for residential and commercial systems (from $\$7.06/W_{DC}$ to $\$2.93/W_{DC}$ for residential and from $\$5.23/W_{DC}$ to $\$2.13/W_{DC}$ for commercial) and 70 percent for utility-scale systems (from $\$4.46/W_{DC}$ to $\$1.42/W_{DC}$).[169] However, other factors can interrupt this general trend; for example, increases in warranty costs and the prices of commodities such as steel and fiberglass (among other factors) drove wind turbine installed system costs on a per-megawatt basis to double between 2000 and 2008 (though these costs went on to decline by 40 percent since 2010).[170]

Importantly, these capital cost trends do not account for technology improvements that improve performance and economics. For wind, improvements in turbine technologies and taller towers have resulted in increased capacity factors. For example, in 2015, capacity factors averaged 25.8 percent for wind projects built from 1998–2003 and averaged 41.2 percent for wind projects built in 2014.[171] Similarly, for utility-scale PV, optimized system design—including use of single-axis tracking and increasing inverter loading ratios—partially contributes to capacity factors increasing from 21 percent for 2010 vintage projects to 26.7 percent for 2014 vintage projects in 2015.

In addition to research and development (R&D)—which is aimed at reducing technology costs through innovation—the investment tax credit (ITC) and PTC, as well as state-level RPS, have driven expansion of VRE, particularly wind and solar. Figure 3.27 shows the substantial increase in wind capacity since 1998 during the period when a PTC has been in effect. It also suggests the wind industry's tendency to increase investments in years when the tax credit was due to expire and its extension was uncertain. The current PTC is scheduled to be phased out after 2019.[172] The solar ITC—currently at 30 percent—will be reduced after 2021 to its statutory level of 10 percent for commercial and industrial projects, and will be phased out completely for residential projects.[173]

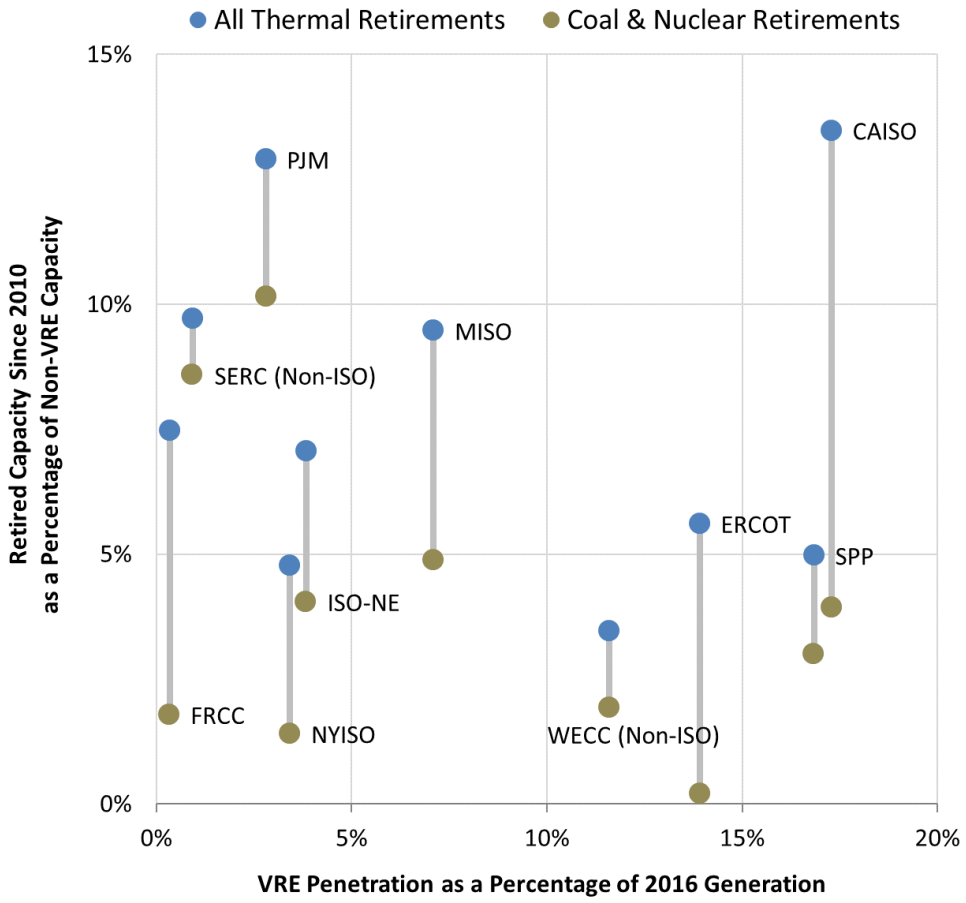
Figure 3.27. Relationship between the PTC and Annual Wind Capacity Additions



The PTC has accelerated wind project deployment significantly—between 2000 and 2013, cumulative wind capacity grew from less than 5,000 MW to more than 60,000 MW—though capacity additions noticeably track the PTC expiration and extension schedule. Similarly, the dramatic decrease in wind capacity additions during PTC expiration years underscore the notion that credits are driving deployment, rather than market decisions. For example, during the PTC expiration "cliff" in 2013, new builds counted for 1 MW of added capacity. After renewal of the PTC, new capacity jumped to 5 MW.[174] This change occurred in the absence of any change in state RPS requirements.

A panel of economists at a May 2017 FERC technical conference cited state-level RPS and Federal tax credits for VRE as examples of market-distorting subsidies and mandates. These policies reduce revenues for traditional baseload power plants by lowering the wholesale electric prices they receive and by displacing a portion of their output. To date, however, the data do not show a widespread relationship between VRE penetration and baseload retirements, as shown in Figure 3.28.[175]

Figure 3.28. VRE Penetration as a Percentage of 2016 Generation versus Retired Capacity since 2010 as a Percentage of Non-VRE Capacity[176]



While concerns exist about the impact of widespread deployment of renewable energy on the retirement of coal and nuclear power plants, the data do not suggest a correlation.

Subsidies

Federal and state governments use subsidies, mandates, and prohibitions to affect how public and private entities behave. Subsidies make the favored behavior or product more appealing relative to other competing products by accelerating its development (as with R&D and direct construction expenditures), lowering its ultimate cost to the consumer (as with tax incentives, low lease payments or grants), or making the product better known and more appealing (customer education, ratings, and marketing). In contrast to subsidies, mandates and prohibitions create absolute requirements for the user for whether and how much of the targeted product to consume.

The Federal Government has always used a variety of subsidies to support a myriad of public and private sector goals. Over the long term, subsidies are spent on different technologies at different times, reflecting differing societal priorities and technology maturities. Early subsidies included Federal construction of hydroelectric dams and multi-purpose water management projects beginning in the 1930s. Energy R&D spending began in the 1950s with the passage of the Atomic Energy Acts of 1946 and 1954, with major Federal investments in the commercialization of nuclear electricity. R&D investments

increased sharply after the oil price shocks and energy crisis in the 1970s, and renewable energy R&D supported VRE.

Accurately accounting for energy subsidies and expenditures is highly dependent on the scope and time period of the analysis. For example, some tax incentives may affect energy industries but are not specific energy-related measures, such as Section 199 of the American Jobs Creation Act of 2004, which allows tax deductions for domestic manufacturing. Natural gas producers, along with many other types of manufacturers, have been able to take advantage of this tax incentive even though it was not an energy-specific measure. This is just one example of the difficulty in examining energy-related subsidies and expenditures both from Federal and non-Federal sources, many of which may not be directly comparable.[II]

As a snapshot of Federal subsidies and support for electricity generating technologies for a given year, Table 3-5 shows electricity production subsidies and support that includes breakouts by direct expenditures, tax expenditures, R&D, and other Federal programs, compiled by EIA for Fiscal Year 2013. Although this data has not been compiled for every year, the 2013 data can be instructive. For example, VRE technologies received a majority of Federal support that year relative to other technologies, particularly reflecting the technical maturity of VRE relative to conventional technologies.

[II] For a longer discussion on energy subsidies and various reports examining energy subsidies, see https://www.eia.gov/analysis/requests/subsidy/pdf/subsidy.pdf.

Table 3-5. Fiscal Year 2013 Electricity Production Subsidies and Support[177]

Beneficiary	Direct Expenditures	Tax Expenditures	Research and Development	Federal and RUS Electricity	Total	Share of Total Subsidies and Support
Coal	61	642	167	30	901	6%
Natural Gas and Petroleum Liquids	18	662	10		690	4%
Nuclear	37	1,109	406	109	1660	10%
Renewables	7,408	3,373	722	176	11678	72%
Biomass	62	9	47	-	118	1%
Geothermal	221	22	2	-	245	2%
Hydropower	194	17	10	171	392	2%
Solar	2,448	1,712	234	-	4393	27%
Wind	4,274	1,614	49	-	5936	37%
Other	209	-	380	5	594	4%
Subtotal Renewables Electric	7,408	3,373	722	176	11678	72%
Electricity - Smart Grid and Transmission	8	211	831	134	1184	7%
Total	7,532	5,996	2,136	449	16112	100%

Similarly, it is important to note how these particular results are driven by the unique nature of a given year. For example, the large direct expenditures for wind and solar overwhelmingly arise due to the Treasury 1603 program enabled by the American Recovery and Reinvestment Act of 2009, which allowed one-time cash grants to eligible renewable generators in lieu of tax credits. This was only available to generators who began construction in 2009–2011, and as such is no longer a direct expenditure.

There is no complete multi-year assessment available that describes and analyzes the Federal subsidies and support provided to different generation technologies over time. Continued examination of Federal subsidies and support, and provision of this information to the public, can better inform the decisions made by Federal, state, and local entities.

Workforce Impacts of Growing VRE Deployment

As the electricity system changes, so do the types of jobs, skills needed, and education or training required. The evolving demands of the grid are creating new opportunities in information and communication technologies and in the deployment of new generation, including natural gas and VRE. Job growth has been strong in the VRE sector, and the solar and wind workforce increased by 25 and 32 percent, respectively, in 2016.[178] DOE's *2017 U.S. Energy and Employment Report* found that the solar and wind industries provide 373,000 and 101,000 jobs, respectively, across the Nation.[179] Veterans

comprise a higher percentage of employees in the electricity industry compared to other industries, and in 2015, the solar industry provided nearly 17,000 jobs for veterans in manufacturing, installation, and project management.[180]

3.8 Flattening Electricity Demand

Between 1970 and 2005, total U.S. electricity generation to meet customer demand grew at a compound annual growth rate (CAGR) of 2.7 percent.[181] But since 2005, generation growth has stalled with a CAGR of only 0.05 percent from 2005 to 2015, even as the Nation's GDP grew by 1.3 percent per year over the same period.[182]

Electricity demand historically had risen with economic growth (real GDP), but the two began decoupling around 2000, as shown in Figure 3.29. EIA attributes this decline in the demand growth rate to a variety of factors, including the cumulative impact of energy efficiency programs, standards, and codes; technology improvements in appliances, lighting, and other end-use equipment; and broader structural changes, such as a shift toward less electricity-intensive industries and slower population growth.[183]

Figure 3.29. Gross Domestic Product and Net Electricity Production, Historical (1950–2016) and Projected (2017–2027)[184] [185] [186] [187]

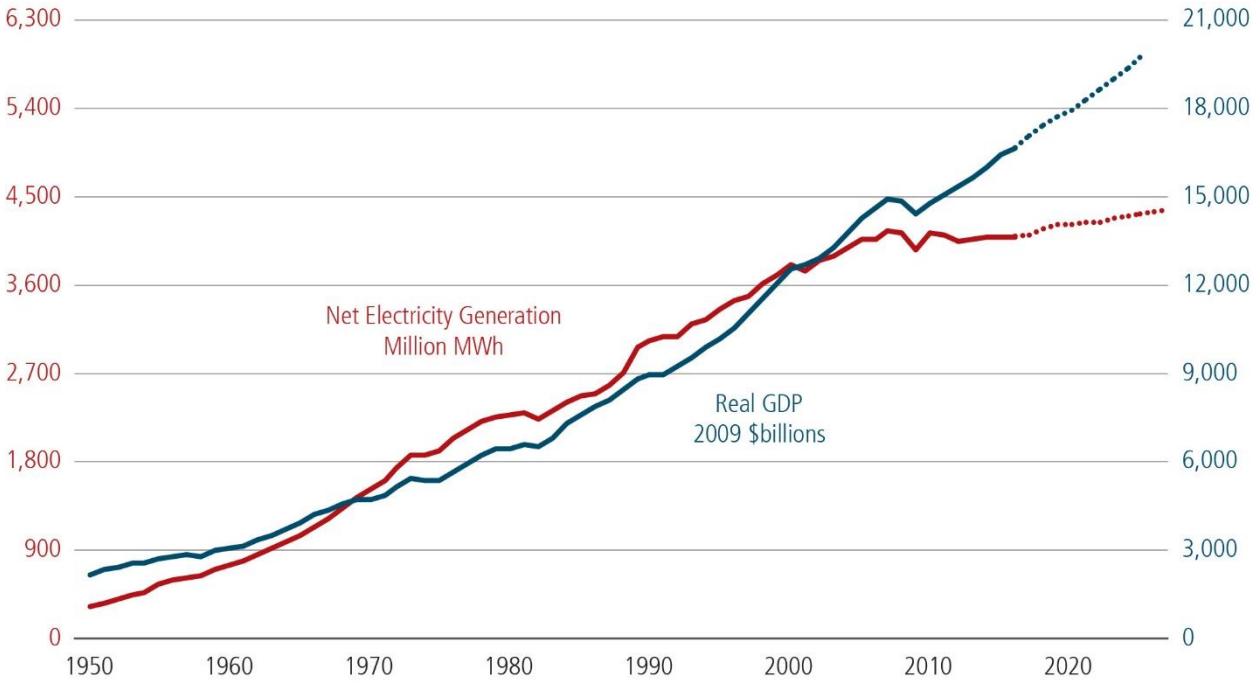
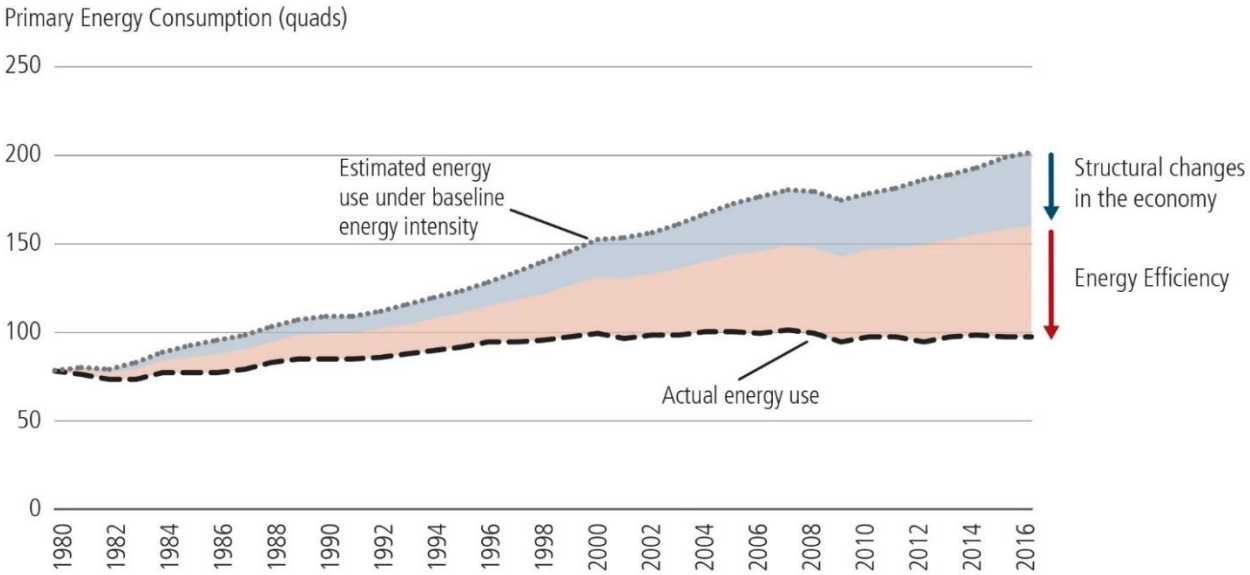


Figure 3.30 shows one analysis of how efficiency improvements, coupled with structural changes in the economy, have led to flattening energy use in recent years. Overall, there has been significant progress across the U.S. economy in improving the value of goods and services produced per unit input of energy. For example, electricity productivity in the industrial sector—measured in dollars of economic output per kilowatt-hour of electricity input—nearly doubled between 1990 and 2014. The noticeable dip in both GDP and net electricity generation in 2008–2009 reflects the U.S. recession, which lowered electricity usage enough to affect power plant economics and prompt some plant closures.[188]

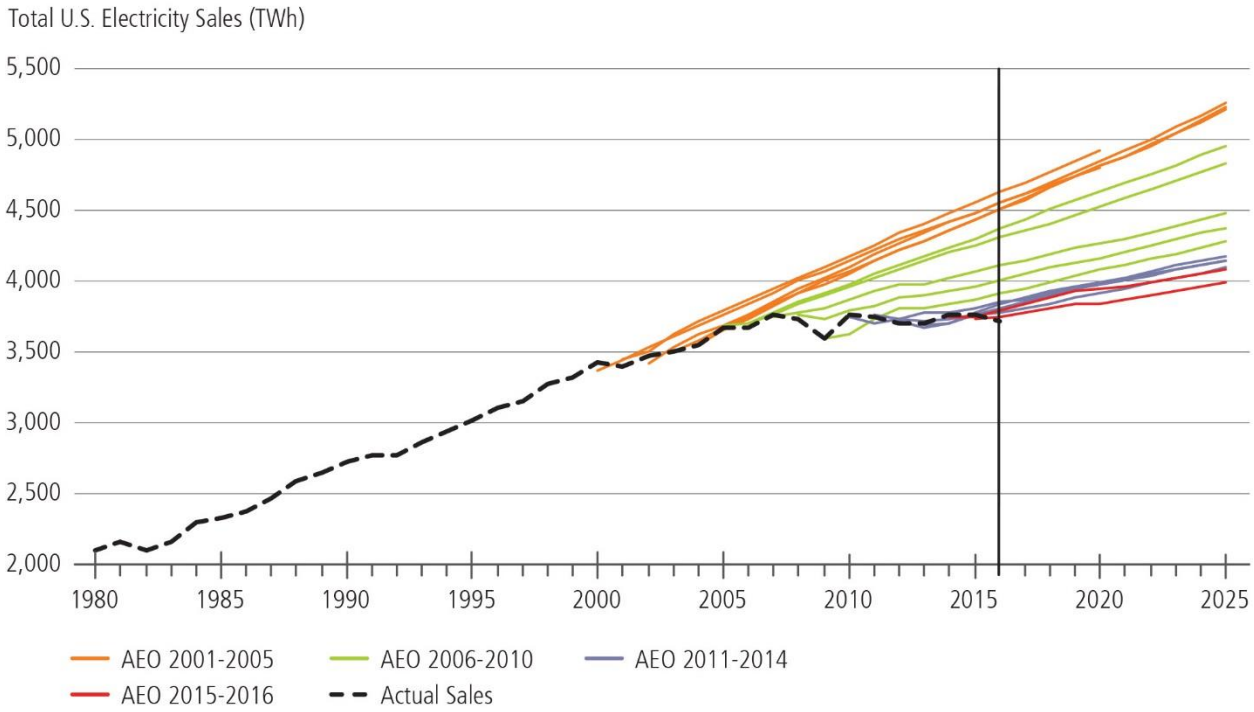
Figure 3.30. Estimated U.S. Energy Savings from Structural Changes in the Economy and Energy Efficiency, 1980–2016[189] [190]



The U.S. economy has made significant progress in improving the value of goods and services produced per unit input of energy, through both energy efficiency and structural changes to the U.S. economy.

Figure 3.31 shows more broadly the impact of these changes on the EIA's Annual Energy Outlook (AEO) Reference case electricity sales forecast for various years. Each AEO forecast is made assuming that laws and regulations in effect at the time of the projection will continue unchanged through the projection period, unless scheduled end dates for those laws and regulations are within that period. The objective is to provide a "business-as-usual case;" no assumptions about new policies are included. Over the past several decades, new Federal and state policies, market forces, and broader economic factors have contributed to lowering levels of electricity consumption compared to what was expected to occur in absence of any new policy, as shown by the comparison of historical Reference case projections to actual U.S. electricity sales (shown as dotted lines in Figure 3.31).

Figure 3.31. EIA Annual Electricity Sales 2000–2016 (terawatt-hours) and AEO Reference Case Electricity Sales Projections 2017–2030[191]



A changing policy and market environment since 2000 has made it challenging to accurately forecast electricity demand. TWh is terawatt-hours.

As stated in QER 1.2:

> Currently, about 90 percent of residential, 60 percent of commercial, and 30 percent of industrial energy consumption are used in appliances and equipment that are subject to Federal minimum efficiency standards implemented, and periodically updated, by the Department of Energy. Between 2009 and 2030, these cost-effective standards are projected to save consumers more than $545 billion in utility costs, reduce energy consumption by 40.8 quads, and reduce carbon dioxide emissions by over 2.26 billion metric tons.[192]

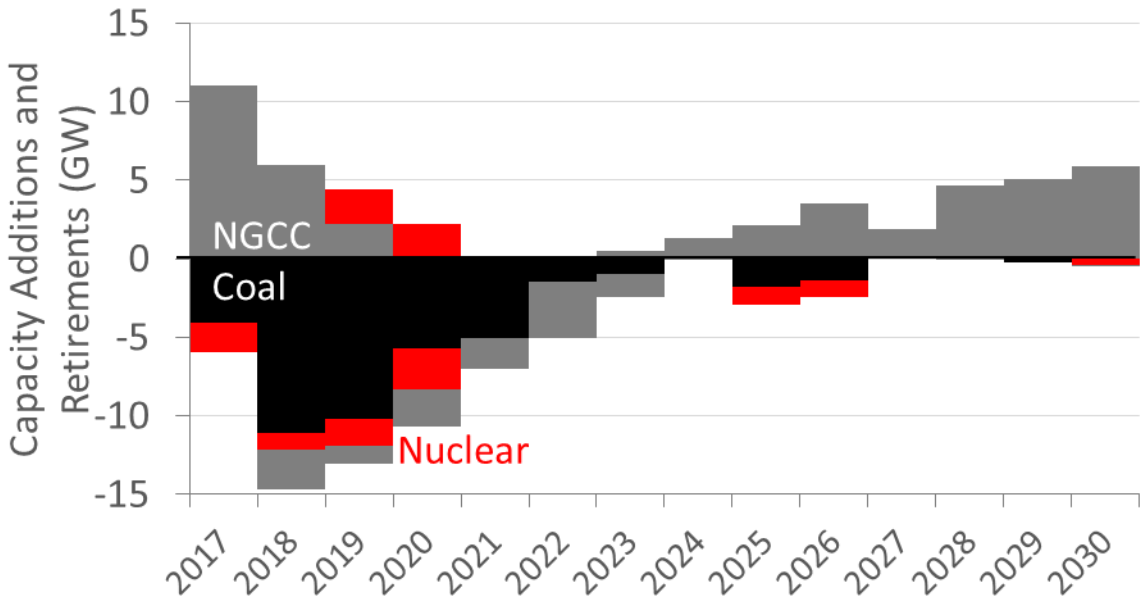
There are two significant impacts from the growth in energy efficiency. First, suppliers can no longer expect robust demand growth. Second, because customers are buying less electricity, the market price of electricity clears lower on the electricity supply curve (all else equal). Thus, higher-cost power plants that might have been dispatched and earned revenues in a higher-demand market are dispatched less frequently and earn less revenue due to increased energy efficiency.

[nn] The report, *Economic and Market Challenges Facing the U.S. Nuclear Commercial Fleet*, produced by Idaho National Laboratory and the Center for Advanced Energy Studies (September 2016), attributes low electricity market prices to "low natural gas prices, low demand growth, increased penetration of renewable generation, and negative electricity market prices."

3.9 Power Plant Retirements Looking Forward

While recognizing the difficulty in making any long-range forecast, it is useful to examine modeled scenarios to understand how the factors affecting retirements are expected to evolve. Figure 3.32 shows the announced and modeled coal, NGCC, and nuclear retirements and additions from 2017 through 2030 in EIA's AEO 2017. This shows that coal retirements are projected to continue in the near term—with 37,800 MW projected to retire between 2017 and 2022—and taper off in the longer term, with another 4,400 MW of retirements between 2023 and 2030. Announced nuclear retirements in the near term account for most projected retirements, with an additional 3,000 MW of modeled unplanned retirements in the period 2019–2020 due to market conditions and uncertainty. A modest number of NGCC plants are also expected to retire in the near term in this modeled scenario.

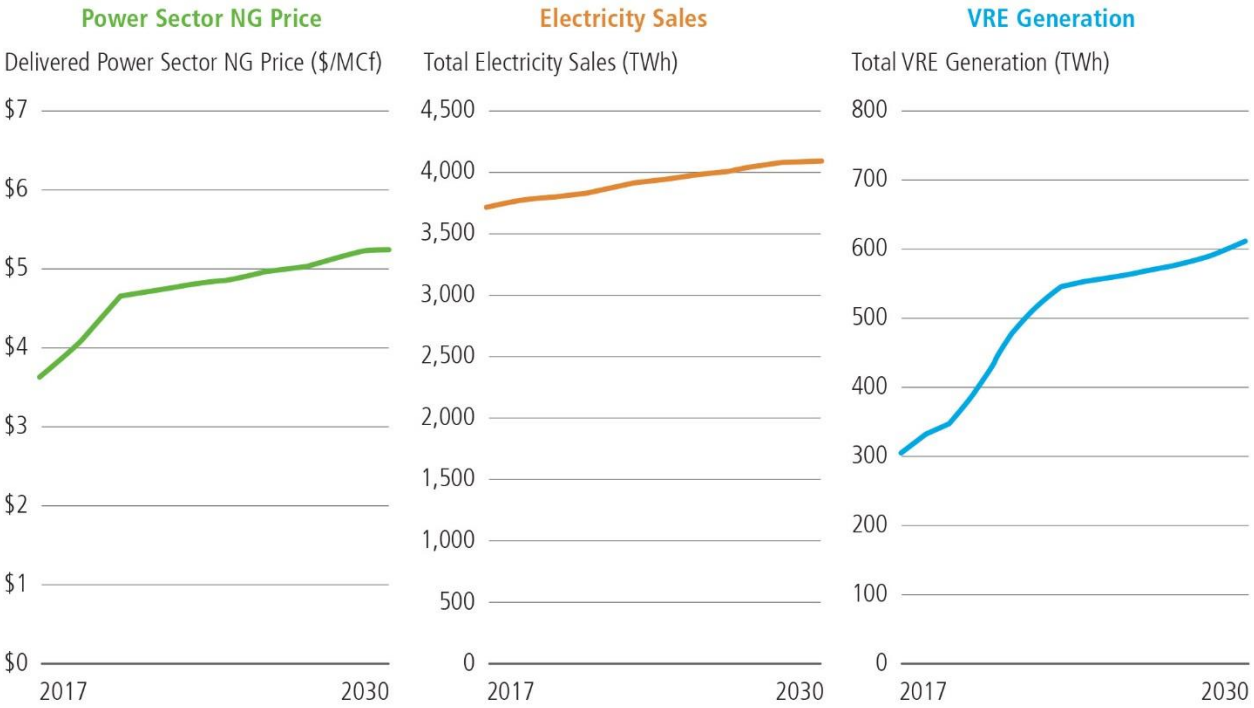
Figure 3.32. Baseload Capacity Additions and Retirements from EIA AEO 2017 (No Clean Power Plan Scenario)[193]



Three factors impacting the economic conditions of baseload generators that are modeled in the AEO—natural gas price, electricity sales, and VRE generation—are shown in Figure 3.33 below. In general, there is a mixed outlook for these factors as they affect baseload generators:

1. Natural gas prices for the electric power sector are modeled to rise modestly, increasing 30 percent over 2017 levels by 2022 and rising more slowly thereafter. While this may provide some upward pressure on electricity prices, natural gas prices are notoriously challenging to predict.
2. Electricity continues to grow at a slow rate—modeled at 0.8 percent CAGR through 2030.
3. Over the same period, VRE generation is modeled to approximately double to 600 terawatt-hours by 2030. The majority of this growth occurs by 2024 and slows thereafter, reflecting the expiration and stepdown of the PTC and ITC in 2020 and 2022, respectively. Based on these trends, unless natural gas prices or electricity demand rise significantly faster than projected, the economic conditions of baseload generators are not projected to change significantly in the near term.

Figure 3.33. Modeled Projections for Natural Gas Price, Electricity Sales, and VRE Generation from EIA AEO 2017 (No Clean Power Plan Scenario)[194]



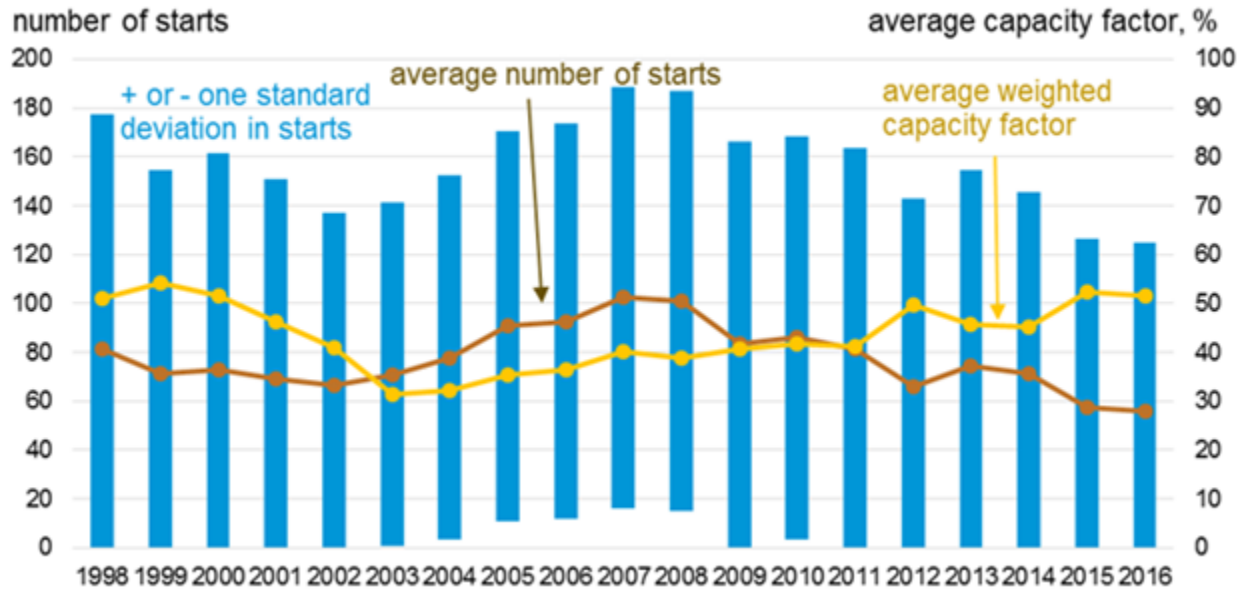
VRE generation includes wind, utility-scale PV, and distributed PV. MCf is million cubic feet

While the financial strains on existing coal, nuclear, and even older natural gas plants have been real and significant, the role of conventional resources continues to evolve. PJM notes the changing nature of baseload:

> "Baseload" can generally be thought of as those units which operate the great majority of hours of the year to meet load requirements. Given the reduction in gas prices, we have seen a noticeable inversion in the types of units which clear in the market in the off-peak hours and thus fit the traditional notion of "baseload." Specifically, due to low energy prices and the overall efficiency of the units, combined cycle natural gas units are dispatched as baseload with coal units more often being cycled and thus dispatched in what has traditionally been deemed "mid-merit" units.[195]

EIA staff analyzed NGCC unit dispatch trends over time, from 1998 to 2016.[196] NGCC plant operation closely follows natural gas prices—when prices were high in the mid-2000s, the number of NGCC starts (when the plant goes from zero output into production) increased as the capacity factor decreased, confirming that these plants were used more in load-following mode rather than baseload-operation mode. Capacity factor has been rising steadily and starts have fallen since about 2010, indicating that NGCC units are being used in more hours at higher capacity factors—i.e., in baseload-type operation (see Figure 3.34).

Figure 3.34. NGCC Capacity Factors and Number of Starts, 1998–2016



Decreased starts and increased capacity factors indicate that NGCC plants are increasingly used for baseload-type operation.

Market conditions will continue to be dynamic, such as with the scheduled phasing out of the wind PTC and solar ITC. Trends in natural gas prices and efficiency gains would also need to be thoroughly examined and accurately forecast in order to get a clearer picture of expected retirements over the coming years. In the event present market, policy, and technology conditions continue, the retirement of coal and nuclear facilities is likely to continue, as well as new builds of natural gas and VRE capacity.

Going forward, coal and natural gas generators will continue to monitor several EPA rules:

- The Steam Electric Effluent Limitation Guidelines have been postponed until EPA completes review of the rule finalized in 2015.[197] EPA recently completed an extended public comment period of the rule and comments are currently being reviewed.[198] Based on the 2015 finalized rule, EPA estimated industry-wide costs at approximately $480 million per year,[199] although industry groups such as the Utility Water Act Group dispute this estimate.[oo] [200]
- The Cooling Water Intake Rule for existing sources is currently being phased in. Regions have been given authority to consider requirements for power plants on a case-by-case basis. EPA estimated an annualized post-tax final rule cost of $147.6 million for electric generators.[201] However, due to the flexibility allotted to the regional permit directors, the compliance timeline and costs are unclear.
- While MATS and CSAPR have affected plant decisions to retrofit or retire in the recent past, most of the capital investment for MATS and CSAPR compliance has already occurred (see Table 3-4). In the future, generators will continue to have smaller operating and maintenance costs associated with MATS. For example, based on generator survey responses, ERCOT estimates an average operating and maintenance cost for MATS of $0.75/MWh,[202] which is approximately

[oo] According to a petition submitted by the Utility Water Act Group, selected *individual* compliance cost estimates from its members included: $308 million (Dynegy), $200 million (NRG Energy), and $400–$500 million (American Electric Power).

3 percent of the average monthly day-ahead wholesale electricity price (approximately $23.5/MWh) for the ERCOT North Hub from 2015 to 2016.[203]

- The Coal Combustion Residuals Rule, prompted by a 2008 coal ash spill, is currently being implemented.[204] EPA estimated the annualized cost of the rule to be $509–$735 million for coal-fired electric utilities.[205]
- The Regional Haze Rule, which currently requires states to submit state plans for compliance by 2021, is expected to mainly affect Western states (the rule aims to improve visibility in national parks, which are located primarily in Western states). It also includes a provision allowing power plants that are already complying with CSAPR (eastern half of the United States[206]) to substitute their compliance status for compliance with the Regional Haze Rule.[207] [208]
- In 2015, EPA finalized New Source Performance Standards, entitled Carbon Pollution Standards, which set CO_2 emission limits for new generators.[pp] These standards are currently under legal challenge.
- The Clean Power Plan rule to reduce CO_2 emissions from existing power plants was promulgated by EPA in 2015 for effect in 2022 for existing plants, but those rules are under review by EPA—which may initiate actions to rescind them—and by the courts.

Several large coal plants built after 1970 with capacities greater than 1,000 MW have announced plans to retire in the next few years. These plants have already made the capital investments needed to comply with MATS, indicating that MATS itself is not the single forcing factor in these retirement decisions. Although these plants were designed to operate around the clock, low wholesale electric prices tied to natural gas were a significant driver that caused them to operate at lower capacity factors. As Rhodium Group analyst John Larsen states:

> The wider market dynamics are more concerning for coal…. For a power plant to make money today, it must be able to ramp up and down to coincide with the variable levels of renewable generation coming online. That makes combined cycle natural gas plants profitable, even at lower prices. [But] coal plants have relatively high and fixed operating costs and are relatively inflexible. They make their money by running full-out.[209]

While there have been significantly fewer retirements of hydropower generation than coal or nuclear, this does not mean that hydropower operators are immune to the same market and regulatory forces that have affected other baseload plants. Depressed prices and costly regulatory barriers decrease the margins on all hydroelectric facilities and, in some cases, cause economic stress.[210] A certain amount of new development continues, primarily through powering existing non-powered dams and installing hydropower in conduits and other constructed waterways. Two hundred and forty-two new hydropower projects, with a total capacity of 3,250 MW, were in the U.S. development pipeline at the end of 2016, including 93 MW under construction. At least nine projects (225 MW) reached commercial operation in 2016.[211]

[pp] Under current market conditions, these standards were not expected to affect new build decisions because economic conditions were already unfavorable for building new coal units. For example, EIA's 2015 AEO, which does not include the Clean Air Act 111(b) carbon standards for new coal plants, builds only a very small amount (roughly 400 MW) of new coal capacity by 2040 beyond what is already planned. https://www.eia.gov/outlooks/aeo/pdf/0383(2015).pdf.

4 Reliability and Resilience

The April 14 memo expressed concerns over whether the erosion of baseload power is compromising a reliable and resilient grid. It also asked whether wholesale energy and capacity markets are adequately compensating attributes that strengthen grid resilience and, if not, the extent to which that could affect grid reliability and resilience in the future. Indeed, a recent National Academies study indicates that there is a growing emphasis within the industry on grid resilience.[212] In this chapter, we address those issues, starting with the question of whether grid reliability has been lessened by the retirement of baseload and other coal, nuclear, and natural gas power plants over the past 15 years.

The Department staff offer three general findings:

> 1) A diverse portfolio of generation resources and well-planned transmission investments are critical to meeting regional reliability objectives. A resource portfolio approach is necessary to ensure ERS, fuel assurance, and flexibility capabilities are available. Conventional generation sources, in particular hydropower, combustion turbines, and steam turbines, are currently the chief providers of these attributes.
>
> 2) One of the greatest challenges to integrating VRE lies in managing its effects (variability, uncertainty, location specificity, non-synchronous generation, and low capacity factor) on grid operations and planning. Lack of long-term forecasting, for example, increases risks when scheduling planned generation outages and managing severe weather events.
>
> 3) There are tradeoffs between multiple desirable attributes for the electric grid. A more reliable and resilient system may be more costly than the least-cost system. Consumer life, safety and health are dependent on a reliable and resilient electric grid, making the grid a national security asset. Infrastructure hardening[213] and grid recovery and restoration strategies require advanced planning and investment.

Reliability

NERC defines BPS reliability as a function of adequacy and operating reliability. In this context, NERC defines adequacy as, "the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components." Operating reliability is defined as, "the ability of the electric system to withstand sudden disturbances to system stability or unanticipated loss of system components."[qq 214]

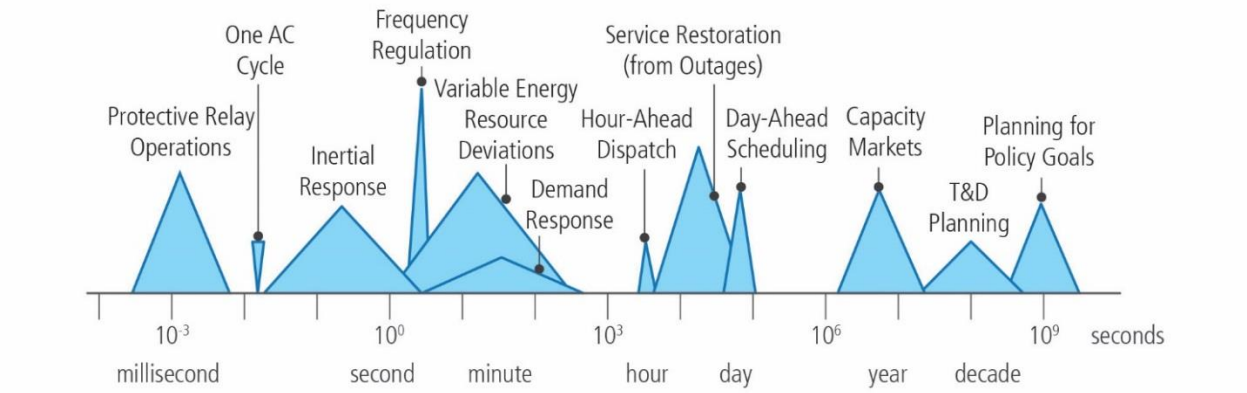
Reliability operates in different time scales. Long-term reliability is closer to resource adequacy: it is the business of ensuring that there will be enough resources available to serve customers' load several years

[qq] *Both* components of reliability are needed. Adequacy, often called "resource adequacy," is much easier to model and thus forecast for the future, particularly a decade or two out. Most longer-term studies, such as by DOE and its national laboratories, largely look at this one aspect of reliability (with some consideration of operational reliability aspects as well). Operational reliability, in contrast, is very difficult (both in data needed and computational complexity) to completely model and thus forecast in definitive terms many years out.

out plus a reserve margin (typically 15 percent). Short-term reliability ensures that there will be enough capacity to meet demand over the next few hours. Maintaining short-term reliability has grown more complex in light of higher levels of VRE, evolving customer electricity usage patterns, and the wider use of 15-minute load metering and customer time-of-use rates. However, grid operators have kept up with these factors by developing new information technology and analysis capabilities, such as more sophisticated wind and solar forecasting tools.

Figure 4.1. illustrates the timescale for different grid events. Events on very short timescales, such as frequency regulation, match second-by-second generation and demand. Medium-term activities and factors include day-ahead and day-of energy markets, security-constrained economic dispatch,[rr] contingency analysis, asset availability, relay and other equipment operations, and operator action. Longer-term activities and factors include system planning, capacity markets, interconnection rules, reliability standards, and energy market designs. Grid operators must thoroughly consider all these timescales and their associated events in ensuring short-term through long-term reliability.

Figure 4.1. System Operation Time Scales[215]



Planning to maintain system reliability depends on managing (potentially) multiple events in varying time scales.

NERC's CEO Gerry Cauley spoke to the Energy Secretary's concerns by describing the current reliability issues.

> As a common thread in each of our Reliability Assessments, the most pressing reliability issues in North America are:
>
> - As conventional resources prematurely retire, sufficient amounts of essential reliability services, such as frequency and voltage support, ramping capability, etc., must be replaced based on the configuration and needs of the system.
> - Resource flexibility is needed to supplement and offset the variable characteristics of solar and wind generation.
> - Higher reliance on natural gas exposes electric generation to fuel supply and delivery vulnerabilities, particularly during extreme weather conditions. Maintaining fuel diversity and security provides best assurance for resilience. Premature retirements

[rr] "Security-constrained economic dispatch [of power plants] is an area-wide optimization process designed to meet electricity demand at the lowest cost, given the operational and reliability limitations of the area's generation fleet and transmission system." https://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/final_ED_03_01_07_rev2.pdf.

of fuel secure baseload generating stations reduces resilience to fuel supply disruptions.

- Because the system was designed with large, central-station generation as the primary source of electricity, significant amounts of new transmission may be needed to support renewable resources located far from load centers.[216]

To make risk-informed decisions about how to maintain and protect BPS reliability, NERC has often stressed the need to study evolving market, technology, policy, and regulatory factors, as well as to understand how they are affecting "fuel supply, generation and transmission infrastructure planning, operations and investment decisions."[217]

Resilience

NERC uses the infrastructure resilience definition that the National Infrastructure Advisory Council developed in 2010: "Infrastructure resilience is the ability to reduce the magnitude and/or duration of disruptive events. The effectiveness of a resilient infrastructure or enterprise depends upon its ability to anticipate, absorb, adapt to, and/or rapidly recover from a potentially disruptive event."[218] Examples of events that test a system's resilience include severe natural events (wildfires, hurricanes, floods, droughts, and earthquakes) and coordinated, extensive physical and cyber-attacks and geomagnetic disturbances.

Resilience is typically achieved through hardening or recovery. Hardening refers to physically changing infrastructure to make it less susceptible to damage. Hardening improves the durability and stability of energy infrastructure, making it better able to withstand the impacts of hurricanes, weather events or attacks. Recovery, by contrast, refers to the ability of an energy facility to recover quickly from damage to any of its components or to any of the external systems on which it depends – typically through storage and redundancy. Recovery measures do not prevent damage; rather, they enable energy systems to continue operating despite damage, and/or they promote a rapid return to normal operations when damages/outages occur. Advanced planning for contingencies, interagency coordination, and training exercises enable an effective restoration process.

BPS reliability is adequate[219] today despite the retirement of 11 percent of the generating capacity available in 2002, as significant additions from natural gas, wind, and solar have come online since then. Overall, at the end of 2016, the system had more dispatchable capacity capable of operating at high utilization rates than it did in 2002.[220] The composition of the BPS and its requirements, however, are changing, so simple extrapolation of previous reliability trends is not prudent. In this chapter, we review current system reliability and resilience, look at how power plant operations are changing with the evolving generation mix, and evaluate potential reliability and resilience issues.

4.1 Assessing Challenges to Reliability

NERC is the primary entity responsible for ensuring BPS reliability,[ss] and collaborates with FERC to ensure compliance. Over the last several years, NERC has consistently highlighted how the power

[ss] NERC is the designated "electric reliability organization" under the Energy Policy Act of 2005, monitoring reliability for all lower 48 states and, under special agreement, portions of the Canadian and Mexican grids.

sector's rapid transformation may require new approaches to reliability measurement and planning in order to ensure continued reliability.[tt] [221] [222] [223] [224] [225]

NERC believes BPS reliability is adequate as measured by various metrics,[226] but is undertaking various initiatives to address potential reliability challenges posed by the changing generation mix. For example, NERC created an Essential Reliability Services Working Group to draw attention to the need to maintain these services[uu] as the resource mix evolves.[227] NERC also created the Integration of Variable Generation Task Force and the Distributed Energy Resources Task Force to address the reliability implications of increasing levels of distributed generation.[228]

NERC's position on the reliability implications of the evolving resource mix is best summarized in its recent communication with DOE (see text box below).

NERC: How the Changing Resource Mix Affects Reliability[229]

The North American BPS is designed to be a highly reliable, robust, and resilient system. The system is interconnected, and the integrated networks work together to maintain reliability through both wide-area interregional planning and coordinated system operations. The adequacy of the system is maintained by having the right combination and amount of resources and transmission to deal with unexpected facility outages or extreme weather events that increase system demand. Operating reliability is maintained in real time through highly coordinated operator actions across many operating companies. The system is also planned as many as 15 years in advance by performing highly detailed, complex, and data-intensive power system simulations.

The resource mix of the BPS is changing in fundamental ways. Variable energy resources, especially wind and solar, are rapidly expanding and capturing the majority share of new capacity additions. Conventional generation (such as coal and nuclear) are retiring and have become economically marginalized. The balancing resource tends to be natural gas, as environmental rules and commodity economics tend to make oil-fired generation uneconomic. Developing hydroelectric resources, a major energy source in some parts of the country (such as the West), is extremely challenging. The confluence of the changing resource mix can fundamentally impact reliability in two major ways:

1. A balancing authority responsible for managing the balance of demand and resources through unit commitment. Forecasting may become capacity deficient and unable to serve firm load. Resources may not be available when needed, particularly those that have not secured onsite fuel. In that instance, manual load shedding may be required to maintain reliability.
2. Large, unanticipated voltage or frequency deviations during a disturbance, which can lead to uncontrolled, cascading instability. With no mass, moving parts, or inertia, increasing amounts of inverter-based resources (such as solar photovoltaic) present new risks to reliability, such as managing faster fault-clearing times, reduced oscillation dampening, and unexpected inverter action.

The rapid changes occurring in the generation resource mix and technologies are altering the operational characteristics of the grid and will challenge system planners and operators to maintain reliability. More specifically:

- Impact of Premature Retirements: Conventional units, such as coal plants, provide frequency support services as a function of their large spinning generators and governor-control settings, along with reactive support for voltage control. Power system operators use these services to plan

[tt] NERC's concerns about the reliability implications of the fast-evolving grid transformation underway were so strong that it chose to *rename* a set of key components of operational reliability from a term understood only by engineers and others directly involved in reliability, the term "ancillary services," to the plainer English and self-defining, "essential reliability services."

[uu] ERS include frequency response, voltage support, and ramping.

and operate reliably under a variety of system conditions, generally without the concern of having too few of these services available. Coal-fired and nuclear generation have the added benefits of high availability rates, low forced outages, and secured onsite fuel. Many months of onsite fuel allow these units to operate in a manner independent of supply chain disruptions.

- Replacement Resource Capability and Characteristics: As the generation resource mix evolves, the reliability of the electric grid depends on the operating characteristics of the replacement resources. Natural gas-fired units, variable generation, storage, and other resources can provide similar reliability services. However, as a practical matter, costs, market rules, or regulatory requirements (or lack thereof) can affect whether these resources are equipped and available to provide reliability services. To ensure reliability, new generator and load resources must maintain the balance between load and generation, especially during ramping periods. In addition, in some jurisdictions, substantial amounts of generation are now being added "behind the meter" (e.g., roof top solar), and these resources are invisible to system operators.

Planning Reserve Margins

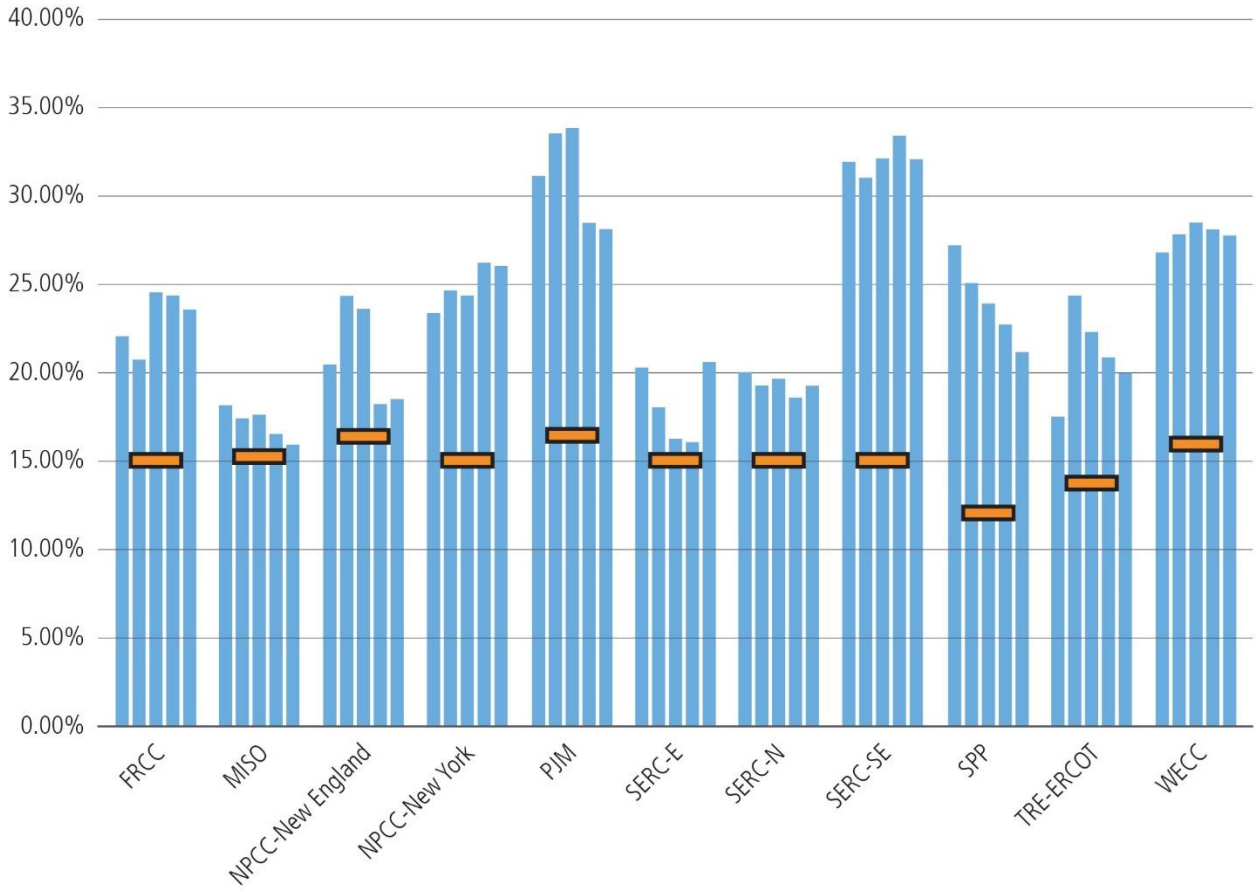
In terms of the resource adequacy part of reliability, NERC reports that all regions project more than sufficient planning reserve margins. NERC and its regional reliability coordinators conduct ongoing analyses to assess resource adequacy as system conditions change over time. Figure 4.2. shows that planning reserve margins[vv] exceed their respective regional targets despite the loss of traditional baseload capacity since 2002.[230] The orange bars in the figure indicate regional or NERC-determined target reserve margins for resource adequacy, which in most cases are administratively set at 15 percent above the predicted peak load. The calculation of resources in most regions includes current VIEU-owned generation and merchant plant capacity (modified by an expected forced outage rate[ww] and reduced by expected retirements), planned capacity additions (with interconnection agreements and customer contracts), renewable generation (derated to expected capacity at peak load hour),[xx] contracted imports, energy efficiency, DR, and distributed generation (derated to expected capacity at peak hour).

[vv] Forecasts of reserve margins may decline in the out-years of a projection because new resources such as power plants, demand response, and energy efficiency are not firm at the time the forecast is made. Because of the uncertainty associated with more distant years, NERC planning reserve margin determinations do not look out past 10 years.

[ww] ISO-New England reports that the expected forced outage rate for generators in their regions have increased because power plants in the region are operating under more stressed conditions. Older power plants in each region are less reliable and go out of service more often as they age. https://energy.gov/sites/prod/files/2014/10/f18/08a-REthier.pdf

[xx] Each ISO and RTO calculates the on-peak contribution of renewable resources as a function of historic resource performance. Land-based wind plants are assumed to deliver four to 14 percent of nameplate capacity during peak summer afternoon periods, and solar resources are assumed to deliver between 10 percent and 80 percent of nameplate capacity. Note, however, that as the level of PV penetration increases, the cumulative amount of PV generation on summer afternoons is moving net load peak hour later.

Figure 4.2. Five-Year Average Reserve Margins across Different Regions (2018–2022)[231]

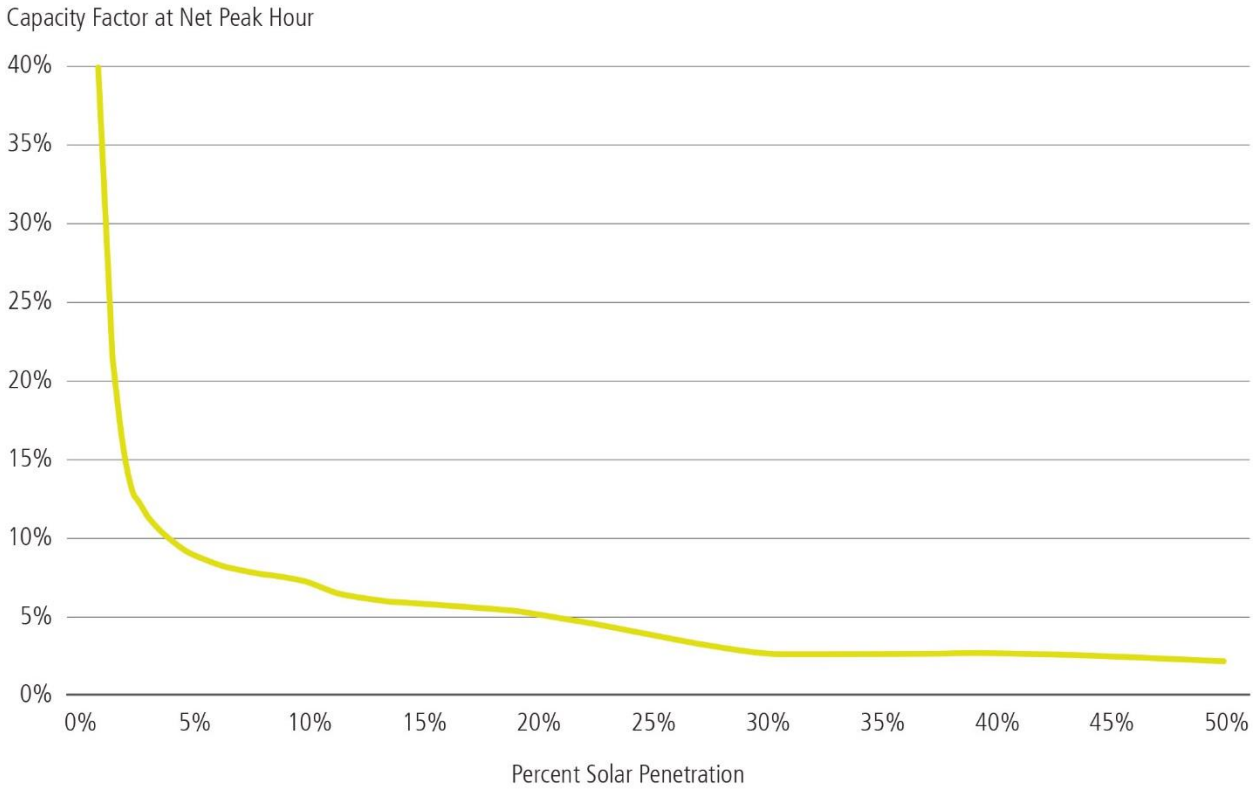


All regions have reserve margins above resource adequacy targets.

The types of resources available within a region affect the reserve margin calculation. Each type of resource has a different availability rate (based on past performance) that reflects the likelihood that it can be relied upon to be available at system peak. For instance, 1,000 MW of coal units with an on-peak availability rate of 90 percent would have a greater impact on the reserve margin than 1,000 MW of wind with an on-peak availability rate of 10 percent; in other words, the actual nameplate capacity totals underlying these reserve margin calculations are significantly higher than the reserve margins suggest. NERC and regional planning authorities are working to understand how common dependencies or failure modes, such as gas pipeline outages or a weather front affecting wind and solar performance across a wide area, could affect reserve margins. NERC and others are also studying how the on-peak hourly capacity factor (similar in concept to capacity value[yy]) of VRE changes as a function of VRE penetration, as shown for solar in Figure 4.3.

[yy] NERC defines capacity value as "the contribution of a power plant to the generation adequacy of the power system. It gives the amount of additional load that can be served in the system at the same reliability level due to the addition of the unit." http://www.nerc.com/docs/pc/ivgtf/omalley-ieee-confidential.pdf

Figure 4.3. Historical Solar On-Peak Capacity Factors in ERCOT[232]



As increased solar penetration in ERCOT shifts the net peak load further into the evening, its net on-peak capacity factor diminishes.

As the Department has previously noted, however, having an adequate planning reserve margin is necessary but not sufficient to ensure resource adequacy (see text box below):

"Rules" to Enable Reliable Operation[233]

In December 2016, DOE articulated four consolidated "rules" that must be maintained to enable reliable operation. These include the following:

1. ***Power generation and transmission capacity must be sufficient to meet peak demand for electricity.***

The power grid must have sufficient capacity available to meet the demand for electricity. Because there are uncertainties in forecasting demand and the potential for generation and transmission outages, the total amount of capacity must exceed the expected level of demand by a given fraction, termed the reserve margin, often about 15 percent.

2. ***Power systems must have adequate flexibility to address variability and uncertainty in demand (load) and generation resources.***

The level of demand changes throughout the day and from season to season. This, and the addition of variable generation such as wind and solar, places a premium on having flexible generation capacity that can change its level of output to account for changes in demand and the amount of generation from variable resources (such as when the wind stops blowing or the sun goes down).

3. ***Power systems must be able to maintain steady frequency.***

The power system uses what is called alternating current (AC), where the electricity reverses direction 60 times per second (60 hertz (Hz)). If this frequency of oscillation were to deviate significantly from 60 Hz, it could damage machines and electronics. Any mismatch between the supply and demand of electricity can cause this sort of deviation, and several mechanisms operating at different timescales are used to maintain a steady frequency.

4. Power systems must be able to maintain voltage within an acceptable range.
In addition to maintaining a steady frequency, the electric grid must also deliver electricity at a given voltage. This voltage varies throughout the power grid, with transformers used to change voltages. Maintaining the correct voltage requires the management of "reactive power," which is a property of AC electricity that allows power to flow. If the levels of reactive power are too high or too low, the voltage level can change, potentially even collapsing catastrophically.

NERC notes that traditional calculations of resource adequacy based on capacity (such as the planning reserve margin) will need to change:

> Until recently, new generators have generally added significant energy capability along with the capacity they provide. With the advent of newer energy limited technologies replacing older ones (e.g., with emerging larger penetrations of variable generation), an assumption of energy adequacy cannot be made simply on the basis of capacity adequacy. Future-looking detailed probabilistic assessments of resource adequacy (energy, capacity and operability), transmission adequacy and congestion are increasingly becoming an essential requirement, consistent with the growing penetration of variable generation, and in the changing non-renewable supply mix environment.[234]

4.1.1 Essential Reliability Services

Reliable operation of the BPS requires a suite of Essential Reliability Services (ERS). One key ERS is the control of system frequency, a parameter which NERC explains as follows:

> Each Interconnection is actually a large machine, as every generator within the island is pulling in tandem with the others to supply electricity to all customers. This occurs as the rotation of electric generating units, nearly all in (steady-state) synchronism. The "speed" (of rotation) of the Interconnection is frequency, measured in cycles per second or Hertz (Hz). If the total Interconnection generation exceeds customer demand, frequency increases beyond the target value, typically 60 Hz, until energy balance is achieved. Conversely, if there is a temporary generation deficiency, frequency declines until balance is again restored at a point below the scheduled frequency.[235]

NERC further expands on the two main types of frequency control, Primary and Secondary:

- Primary frequency control (immediate) comes from automatic generator governor response, load response, and other devices based on local (device-level) frequency-sensing control systems. In general, frequency response refers to the initial actions provided by the autonomous devices within an interconnection to arrest and stabilize frequency deviations, typically from the unexpected sudden loss of a generator or load. Primary frequency control is quick and automatic; it is not driven by any centralized control system, and it begins seconds after a system frequency event. Response to a frequency event can be provided by various sources, including generation resources, loads, and storage devices.
- Secondary frequency control (seconds to minutes) and tertiary frequency control (ten minutes and longer) -- Secondary and tertiary control are the centralized, coordinated control of generation, demand response, and storage resources, and these controls are performed

> by the system operator's energy management system over minutes to hours to balance generation and load.[236]

In addition to frequency control, NERC provides definitions for two other ERS, ramping and voltage support:

> **Ramping** – Ramping is related to frequency, but more in an "operations as usual" sense rather than after an event. Changes in the amount of non-dispatchable resources, system constraints, load behaviors, and the generation mix can impact the ramp rates needed to keep the system in balance.
>
> **Voltage** – Voltage must be controlled to protect the system and move power where it is needed. This control tends to be more local in nature, such as at individual transmission substations, in sub-areas of lower-voltage transmission nodes and the distribution system. Ensuring sufficient voltage control and "stiffness" of the system is important both for normal operations and for events impacting normal operations (i.e., disturbances).[237]

If grid voltage levels fall too low, customers connected to distribution networks may see their devices "brown out" and stop working. An area that has inadequate voltage support is vulnerable to voltage collapse, so the system must be operated such that a single contingency would not result in voltage collapse or cascading outages.

Generators provide voltage support by producing both real and reactive power. As FERC explains in its 2016 Reliability Primer:

> Power transferred along transmission lines consists of both "real" power and "reactive" power. The real power is the energy that is capable of performing work in electrical devices including industrial equipment, refrigerators, or toasters. Reactive power is needed to maintain the voltage as well as electric and magnetic fields in AC equipment, which includes air conditioners, motors, transmission lines, and other devices. Together, real power and reactive power comprise apparent power, which is measured in units of Volt-Amperes or kilo Volt-Amperes - kVA.
>
> Reactive power cannot be transmitted as far as real power and instead must be replenished locally. Moreover, a deficit in reactive power causes voltage to drop. This is seen when the lights dim as an electric motor starts. While reactive power consumed by facilities or devices tends to cause the voltage to drop, it can also be produced or injected into the system to increase voltage in what is often referred to as "voltage support." This is accomplished in a variety of ways, including by adjusting the reactive power output of generators or by activating capacitor banks or other power electronic equipment. If reactive power is not supplied promptly and in sufficient quantity, voltages decline, and in extreme cases a "voltage collapse" may result.[238]

FERC Order No. 827, issued in June 2016, revised FERC's *pro forma* Large Generator Interconnection Agreement and *pro forma* Small Generator Interconnection Agreement to eliminate the previous exemption for wind generators from reactive power requirements, thereby requiring all newly interconnecting, non-synchronous generators—including new wind generators—to provide reactive power as a condition of interconnection to the transmission system. FERC wrote:

> We therefore conclude that improvements in technology, and the corresponding declining costs for newly interconnecting wind generators to provide reactive power, make it unjust, unreasonable and unduly discriminatory and preferential to exempt such non-synchronous generators from the reactive power requirement when other types of generators are not exempt. Further, requiring all newly interconnecting non-synchronous generators to design their Generating Facilities to maintain the required power factor range ensures they are subject to comparable requirements as other generators.[239]

FERC's primary frequency response Notice of Proposed Rulemaking proposes to require new large and small generators to install, maintain and operate equipment capable of providing primary frequency response as a condition of interconnection.[240]

NERC explains the various reserve products from which grid operators obtain these ERS:

- **Frequency-Responsive Reserve:** On-line generation with headroom that has been tested and verified to be capable of providing droop […] In most cases, only portions of a, b and c in [Figure 4.4] qualify as Frequency Responsive Reserve.
- **Nonspinning Reserve:** Operating Reserve capable of serving demand or Interruptible Demand that can be removed from the system, within 10 minutes. (This is c in [Figure 4.4])
- **Operating Reserve:** That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages, and local area protection. (This is a+b+c+d+e in [Figure 4.4]).
- **Regulating Reserve:** An amount of spinning reserve responsive to Automatic Generation Control, which is sufficient to provide normal regulating margin. (This is "a" in [Figure 4.4])
- **Replacement Reserve:** (This is d+e in [Figure 4.4]). NOTE: Each NERC Region sets times for reserve restoration, typically in the 30–90 minute range. The default contingency reserve restoration period is 90 minutes after the disturbance recovery period.
- **Spinning Reserve:** Unloaded, synchronized, resource, deployable in 10 minutes. (This is b in [Figure 4.4]). [241]

Figure 4.4. NERC Definitions of Reserves Used to Provide ERS[242]

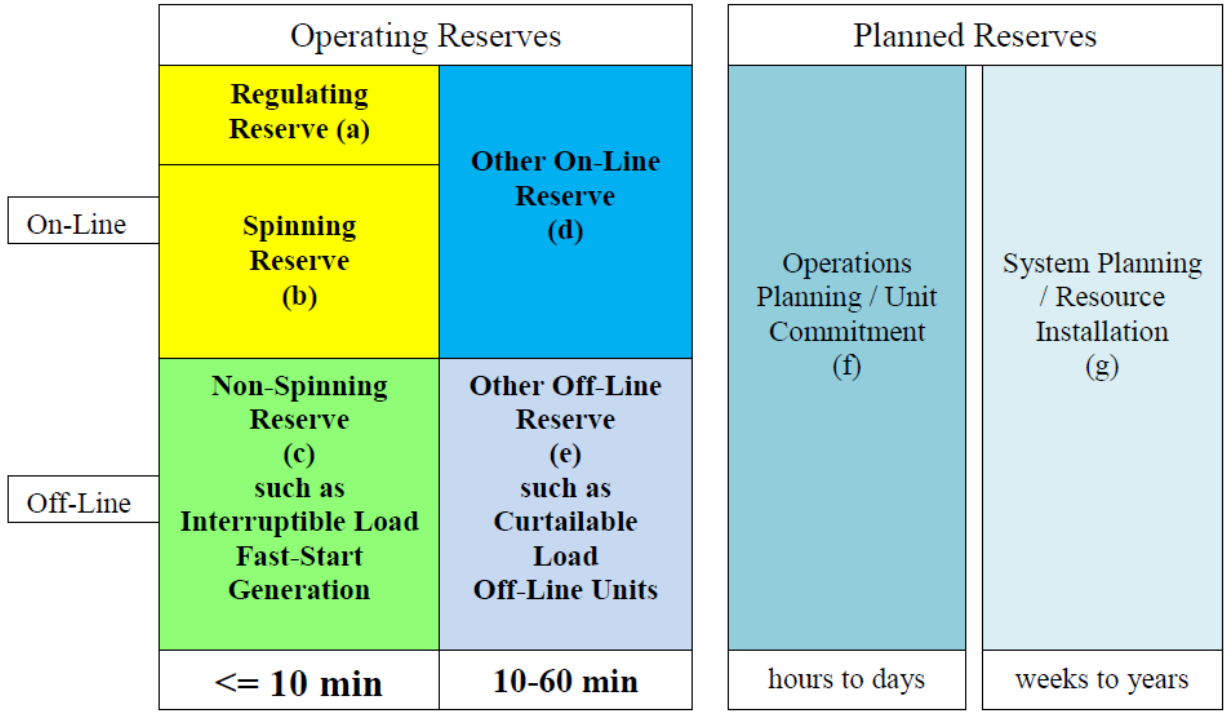
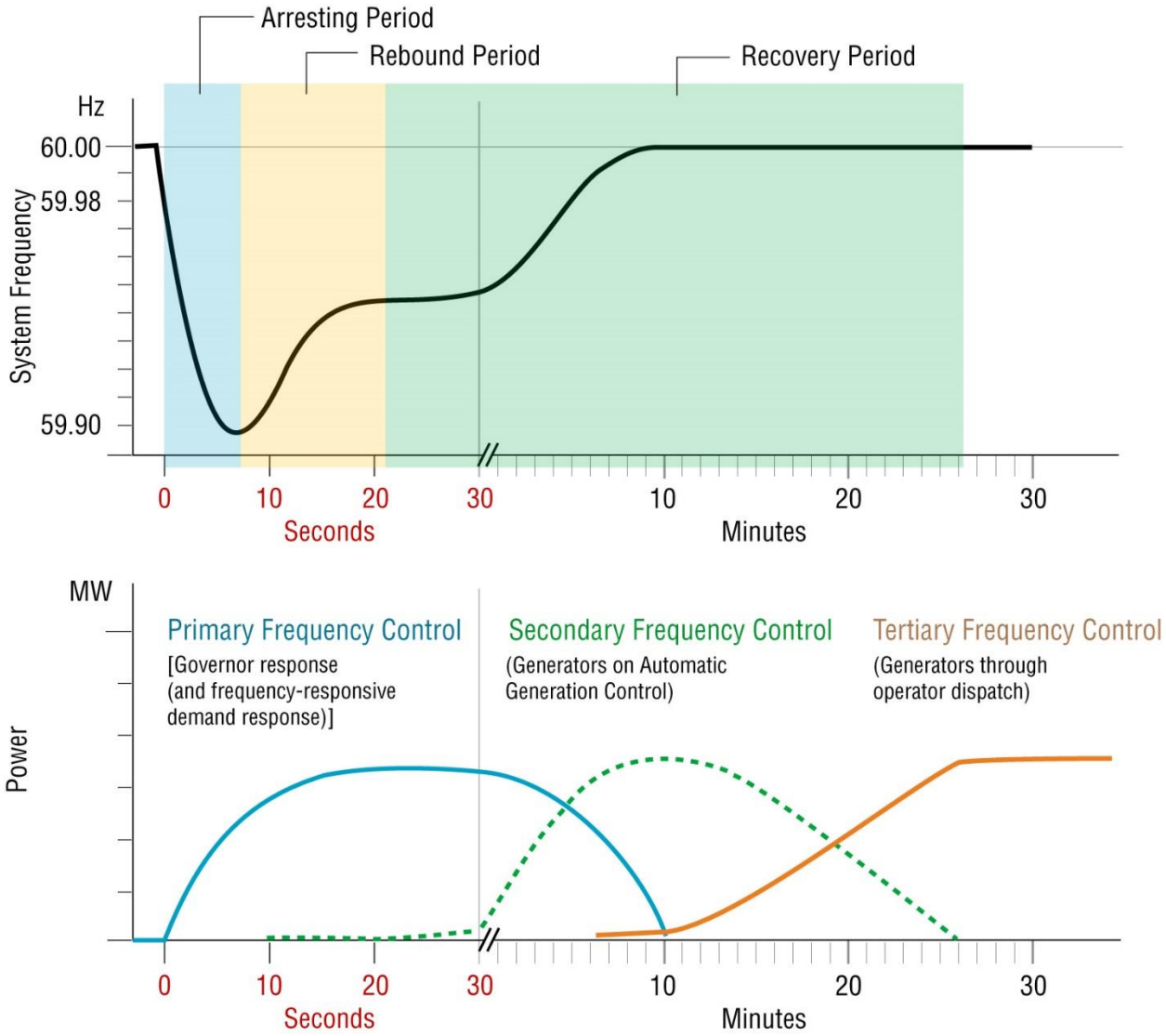


Figure 4.5 shows how system frequency falls after a major generation loss. The decline in frequency is determined by the size of the generation loss event and the availability of frequency control reserves to respond. The frequency rebound that follows is due to automated primary frequency control measures

(governor response from generators and frequency-responsive DR from customer loads controlled by relays). Secondary frequency control may derive from many sources, including from local plant controls, from a centralized control system, or from instructions issued by balancing authorities. Tertiary frequency control refers to operator-initiated, off-line resources. If these frequency management measures don't work, system frequency can keep dropping, resulting in under-frequency load shedding procedures.

Figure 4.5. System Frequency after a Grid Event (Top) and How Frequency Control Mechanisms Work to Restore Frequency (Bottom)[243]



System operators have a number of levels of frequency control to manage a significant grid event.

Not all generators can provide primary frequency control, as explained by Lawrence Berkeley National Laboratory (LBNL):

> Some generators, including all current nuclear generators, most wind turbines in North America, as well as many new natural gas turbines do not provide governor response. Other generators, which may be capable of providing governor response, are sometimes operated in ways that prevent them from providing that response. For example, a generator operated

> at its maximum capability cannot provide upward primary frequency control because it has no head room. Finally, some generators have additional controls […] that override the sustained delivery of governor response.[244]

NERC recognized several years ago that the changes affecting the grid—particularly retirement of traditional baseload capacity, increased generation from VRE, and greater use of DR and distributed generation—could create BPS reliability problems without careful study and management. In 2014, a task force under NERC's direction identified ERS as the elemental reliability building blocks from supply and demand resources that are necessary to maintain grid reliability. NERC stated that:

> To meet the needs of the future Bulk Power System, maintaining sufficient ERS will include a mix of market approaches, technology enhancements, and reliability rules or other regulatory rule changes. While the solution sets will likely be different in various regions, it may be necessary for regulators to make appropriate adjustments to market rules and reliability standards that will ensure reliable operation of the BPS.[245]

Although NERC has requirements for balancing areas,[zz] it does not require that individual generators provide primary frequency response, which involves the automatic, autonomous, and rapid action of turbine governors or equivalent controls. Further, there is no mandatory compensation for primary frequency response, though FERC Order No. 755 provides for compensation for secondary frequency response.[246] Because provision of primary frequency response may require a generator to operate at less than its full output (so it can increase power production if needed to manage frequency), standing prepared to provide frequency response services means that a generator may forgo some potential revenues.

The reliability attributes discussed above are recognized as valuable, but regional procurement and compensation for these services varies across the centrally-organized markets. In vertically integrated regions that use bilaterally organized markets, it is generally the incumbent utility's obligation to provide ERS; some interconnection agreements specify other generators' reliability service obligations if any.

4.1.2 Inertia and Inertial Response

PJM explains how conventional generators provide inertia:

> Due to electro-mechanical coupling, a generator's rotating mass provides kinetic energy to the grid (or absorbs it from the grid) in case of a frequency deviation to arrest frequency change and stabilize the electric system. The contribution of inertia is an inherent and crucial feature of rotating synchronous generators.[247]

Every operating conventional generator has mass that spins, including rotors, turbines and other masses connected to the shaft of the generator or motor. The rotating mass in each generator collectively provides inertia to help keep grid frequency at a relatively stable level, for example slowing the rate of frequency drop after a major grid event and giving other automatic controls time to act to restore frequency. Inertia also works to slow the spike in frequency that occurs after the loss of a large amount of load (for instance, if part of a city "blacks out" suddenly from a transmission or distribution failure).

[zz] NERC Reliability Standard BAL-003-1.1 establishes requirements for balancing authorities, but does not include requirements for individual generator owners or operators. However, some ISOs/RTOs, including CAISO, ISO-NE, and PJM, have implemented operating requirements for individual generating resources within their regions. Regional Reliability Standard BAL-001-TRE-01 (Primary Frequency Response in the ERCOT Region) establishes requirements for the balancing authority, generator owners, and operators in ERCOT.

Recently, manufacturers have designed electronic controls for newer model wind turbines that can provide automatic generation control, primary frequency response and synthetic inertia. General Electric (GE) notes:

> A key difference between wind inertia and fast frequency response from other resources (batteries, PV, flywheels) is that wind turbines do not need to be pre-curtailed in order to provide synthetic inertial response. Wind inertia extracts some of the kinetic energy from the spinning rotor and uses it to provide increased power output within seconds.[248]

There has not yet been much analysis of how much primary frequency response will be needed as the composition of the grid changes, nor how best to complement primary frequency response from traditional sources, such as governors, with electronics-based synthetic inertia or non-governor-based forms of primary frequency response, such as storage or DR. These are substantive engineering questions that merit further study, particularly in a future with increasing VRE levels and decreasing rotating mass-based inertia.[249]

4.1.3 Energy Storage

Energy storage will be critical in the future if higher levels of VRE are deployed on the grid and require additional balancing of energy supply and demand in real time. A few storage mechanisms such as pumped hydroelectric storage and thermal energy storage have been used for years to shift energy demand from peak to off-peak periods. A grid with higher levels of VRE and more dynamic customer loads will need more of the services that energy storage can provide by acting on both the supply and demand side, including energy, capacity, energy management, backup power, load leveling, and ERS, over periods from seconds to hours or days. However, the need for storage may not be as great for a grid more reliant on traditional baseload generation.[250]

DOE has been investing in energy storage technology development for two decades, and major private investment is now active in commercializing and the beginnings of early deployment of grid-level storage, including within microgrids.[aaa] The DOE Grid Energy Storage program notes that as energy storage technologies mature and become commercially viable, they will need to achieve the following:

- Cost competitive energy storage technology—Achievement of this goal requires attention to factors such as life-cycle cost and performance (round-trip efficiency, energy density, cycle life, capacity fade, etc.) for energy storage technology as deployed. It is expected that early deployments will be in high value applications, but long term success requires further cost reductions and the ability to monetize revenues for all grid services that storage provides.
- Validated reliability and safety— Validation of the safety, reliability, and performance of energy storage is essential for user confidence.
- Equitable regulatory environment— Value propositions for supply-side grid storage depend on reducing institutional and regulatory hurdles to levels comparable with those of other grid resources.[bbb] [251]

[aaa] Storage is an important component of most micro-grid designs reliant on VRE and is expected to play an essential role in helping customers and the BPS recover from extreme weather events (and should improve resilience and recovery following severe, high-impact events).

[bbb] A recent FERC Notice of Proposed Rulemaking seeks to identify and reduce such barriers for increased participation by energy storage in centrally-organized wholesale markets.

- Industry acceptance—industry adoption requires manufacturers to have confidence that storage will deploy as expected, and deliver as predicted and promised.[252]

Table 4-1 details DOE analysis of how energy storage options can be used to provide grid-level services.

Table 4-1. How Various Energy Storage Options Can Deliver Grid-Level Applications[253]

Application	Description	CAES	Pumped Hydro	Flywheels	Lead-Acid	NaS	Li-ion	Flow Batteries
Off-to-on peak intermittent shifting and firming	Charge at the site of off peak renewable and/ or intermittent energy sources; discharge energy into the grid during on peak periods	◑	◑	○	●	●	●	●
On-peak intermittent energy smoothing and shaping	Charge/discharge seconds to minutes to smooth intermittent generation and/or charge/discharge minutes to hours to shape energy profile	○	◑	◑	●	●	●	●
Ancillary service provision	Provide ancillary service capacity in day ahead markets and respond to ISO signaling in real time	◑	◑	◑	◑	◑	◑	◑
Black start provision	Unit sits fully charged, discharging when black start capability is required	◑	◑	○	●	●	●	●
Transmission infrastructure	Use an energy storage device to defer upgrades in transmission	○	○	○	●	●	●	●
Distribution infrastructure	Use an energy storage device to defer upgrades in distribution	○	○	○	●	●	●	●
Transportable distribution-level outage mitigation	Use a transportable storage unit to provide supplemental power to end users during outages due to short term distribution overload situations	○	○	○	◑	●	●	●
Peak load shifting downstream of distribution system	Charge device during off peak downstream of the distribution system (below secondary transformer); discharge during 2-4 hour daily peek	○	○	○	●	●	●	●
Intermittent distributed generation integration	Charge/Discharge device to balance local energy use with generation. Sited between the distributed and generation and distribution grid to defer otherwise necessary distribution infrastructure upgrades	○	○	○	●	◑	◑	◑
End-user time-of-use rate optimization	Charge device when retail TOU prices are low and discharge when prices are high	◑	◑	○	◑	◑	◑	◑
Uninterruptible power supply	End user deploys energy storage to improve power quality and /or provide back up power during outages	○	○	◑	●	●	●	●
Micro grid formation	Energy storage is deployed in conjunction with local generation to separate from the grid, creating an islanded micro-grid	○	○	○	●	●	●	●

Definite suitability for application ●; Possible use for application ◑; Unsuitable for application ○

State policies are emerging to encourage further use of energy storage technologies for grid support and energy security. California has directed its utilities to acquire 500 MW of energy storage by 2020; Massachusetts has ordered its utilities to procure 200 MWh of energy storage by the end of 2019; New York's legislators have proposed creation of an Energy Storage Deployment Program, with a 2030 procurement target; Maryland has adopted at 30 percent investment tax credit for storage facilities; and Nevada's legislature has passed a storage incentivize. These programs are generally technology-neutral and will support the use of storage at the grid-level or behind the meter (on the customer's premises).[254] [255]

4.1.4 Transmission

The transmission system is a vast engineered network that transmits electricity from generators to local substations for distribution to end-use consumers. As DOE's *Annual U.S. Transmission Data Review* (2016) states, "Transmission planning activities are undertaken to enable future reliable and efficient utilization of transmission facilities by addressing, among other things, reliability concerns, constraints, and congestion."[256] Transmission reliability is maintained by enforcing operating procedures that ensure efficient system utilization, including preventing users from transmitting more power over a line than its

rated power capacity. Transmission congestion results from the inability to dispatch the lowest-cost generation resources due to transmission constraints.

Transmission investments provide an array of benefits that include providing reliable electricity service to customers, relieving congestion, facilitating robust wholesale market competition, enabling a diverse and changing energy portfolio, and mitigating damage and limiting customer outages (resilience) during adverse conditions. Well-planned transmission investments also reduce total costs. SPP analyzed the costs and benefits of transmission projects from 2012–2014 and found that the planned $3.4 billion investment in transmission was expected to reduce customer cost by $12 billion.[ccc] This yielded an estimated benefit of $3.50 for every dollar invested in the region.[257]

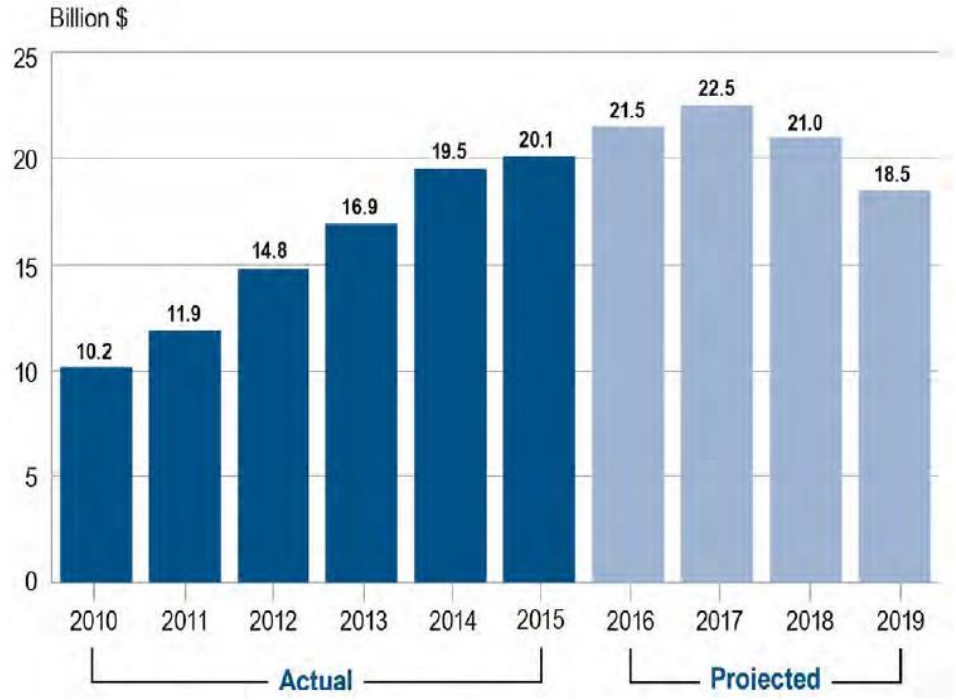
A robust transmission system is needed to provide the flexibility that will enable the modern electric system to operate. Although much transmission has been built to enhance reliability and meet customer needs, continued investment and development will be needed to provide that flexibility.

The challenge for building transmission continues to revolve around the three traditional steps involved, each of which can be time-consuming, involved, and complex: (1) demonstrating a need for the transmission project, also known as transmission planning, (2) determining who pays for the transmission project, also called cost allocation, and (3) state and Federal agency siting and permitting. FERC has taken steps to help with the first two, with reforms such as Order No. 1000, which remains a work in progress.[258] [259] [260] [261] [262] Transmission planning entities, as well as regional state-based groups, are also contributing to improving these three necessary process steps. The current and past administrations, aided by various new Federal laws, have issued various Executive Orders and other initiatives to improve the processes involved in siting and permitting of transmission when Federal lands or waters are involved.

All three transmission building steps can be time-intensive and complex; in particular, siting and permitting for large networks or long multi-state lines is challenging. [263] [264] [265] The second necessary step of cost-allocation can be time-consuming as well. For example, large overlay networks now being built in MISO ("Multi-Value Projects")[266] and SPP ("Highway/Byway Plan")[267] required several years of sensitive negotiations among states brokered by the respective Organization of MISO States and SPP Regional State Committee to determine the cost allocation of each large transmission buildout.[268] [269]

[ccc] Nearly $12 billion in net present value benefits for consumers over the next 40 years, or around $800 for each person currently served by SPP, or $2,400 per each metered customer.

Figure 4.6. EEI Historical and Project Transmission Investment (Nominal Dollars)[270]



Prudent and well planned transmission can reduce total system costs by reducing localized congestion that sometimes leads to high wholesale electricity prices at transmission-constrained nodes. Transmission investments in future years could increase as utilities and system operators seek to mitigate reliability impacts of plant closures and bring new generation to load centers.

4.1.5 System Requirements to Meet Higher Levels of VRE on the Grid

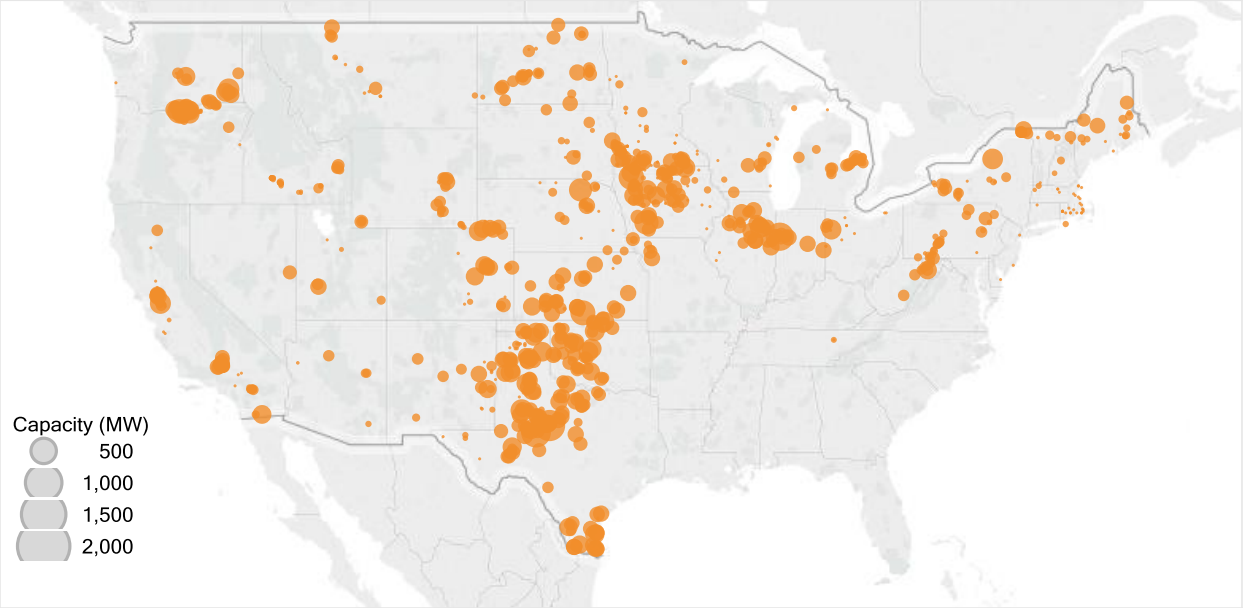
Levels of wind and solar penetration—including distributed and utility-scale installations—have grown in recent years from 0.3 percent of total annual generation nationwide in 2002 to 6.9 percent in 2016.[ddd] [271] Various integration studies (see Appendix B:) have explored grid operations at higher levels of VRE penetration (ranging from 10 percent to 60 percent) and examined the technical challenges for grid operators.[eee] These challenges can generally be met at lower levels through a number of changes to grid operation, planning, and transmission expansion practices, and with other sources of grid flexibility. Solutions vary by region, depending on existing transmission constraints, generators, sources of flexibility, and institutions and markets – each of which comes with associated implementation costs and other consequences to address. Costs can change over time as technologies and markets evolve, or

[ddd] AEO 2017 reference case indicates that this could grow to 17% by 2030.

[eee] The studies (see Appendix B) that look into the distant future are exploratory only and represent initial investigations into how to implement high levels of VRE. They do not look into all the operational aspects of reliability due to the needed complex and computationally challenging modeling. Typical assumptions (sometimes implicit) include successful siting of (at times long multistate) transmission lines and new generation, sufficient new and existing economically viable conventional generation and other resources to support the VRE, institutional and market changes, and relevant grid modernization-type spending at both the transmission and distribution level. One study, for the ease of modeling, even assumes the nation's 66 balancing authorities, including their governing boards and member states, would agree to one national joint dispatch). Some of these assumptions are non-trivial. These studies recognize that given enough time and money, power system engineers can make any resource and configuration reliable, as long as the laws of physics are not violated; whether the changes needed are indeed affordable, doable, and desirable may be a different question. Also, affordability was typically not in the scope of these studies.

as other enabling technologies such as storage mature. Grid operators and planners continually evaluate and determine how to maintain reliability as the resource mix changes and evolves.

Figure 4.7. Location of the Existing Wind Fleet[272]



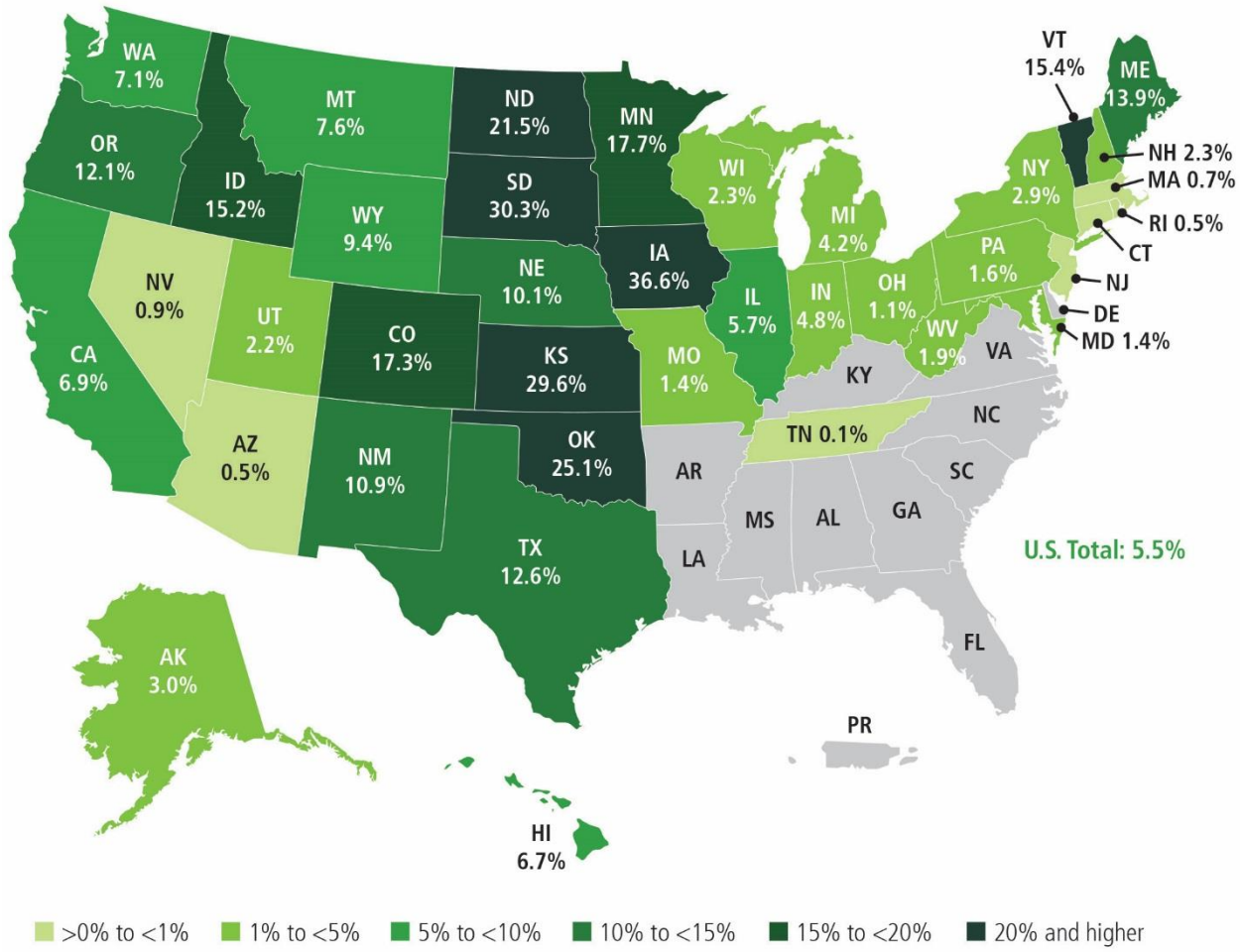
Most of the contiguous United States' wind power plants are installed in the center of the Nation, which has the best wind resources.

Total penetration of VRE is increasing rapidly in several regions, and wind represents the majority of current installed VRE. Wind turbines have contributed more than one-third of the nearly 200,000 MW of total utility-scale generating capacity added since 2007, reflecting a combination of improved wind turbine technology and lower costs, increased access to transmission capacity, state-level RPS, and Federal tax credits and grants. Distribution of wind capacity across the contiguous United States is shown in Figure 4.7.

Percentage wind generation by state is shown in Figure 4.8. In particularly windy hours, wind output in regions with significant wind capacity can be very high. On May 16, 2017, the CAISO hit a new daily renewables record when the combination of wind, solar, hydro, and other renewables served nearly 42 percent of electricity demand; during peak renewables production (the 2:00 p.m. hour), renewables supplied nearly 72 percent of electricity.[273] In Texas, at the end of 2016, ERCOT had more than 17,600 MW of installed wind capacity and 566 MW of utility-scale solar capacity.[274] ERCOT reached 50 percent wind penetration in the early morning on March 23, 2017, when load was below 29,000 MW; at 5:00 p.m. that afternoon, when peak load hit 45,391 MW, wind contributed about 30 percent to the energy needed to meet that peak.[275] SPP recently set a new wind-penetration record of 52.1 percent on February 12, 2017, the highest across North American RTOs.[ggg] [276] [277]

[ggg] On the other hand, there are times when wind generation can be low. For example, ERCOT reports that for 2016, wind generation was below 2,500 MW (approximately 15% of total operating wind capacity as of November 2016) for 17 percent of the year's hours. http://www.ercot.com/news/releases/show/113533.

Figure 4.8 Wind Energy Share of Electric Generation by State, 2016[278]



One of the greatest barriers to widespread VRE adoption is the challenge of managing its variability and corresponding impacts on net load. Table 4-2 summarizes the characteristics of VRE, the challenges to integration, and how to mitigate those challenges.

Table 4-2. Characteristics of VRE, Grid Integration Challenges, and Mitigation Options[279]

Wind & Solar Characteristics	Potential Grid Integration Challenges	Mitigation Options
Variability	Generator output can vary as underlying resource fluctuates.	In many power systems, sufficient flexibility exists to integrate additional variability, but this flexibility may not be fully accessible without changes to power system operations or other institutional factors (e.g., increased ramping of generation and improved coordination across markets and balancing areas) (Lew et al. 2013).
Uncertainty	Generation cannot be predicted with perfect accuracy (day-ahead, day of).	Integration of advanced renewable supply forecasting into dispatch and market operations has reduced uncertainties, improved scheduling of other resources to reduce reserves and fuel consumption, and enabled VRE to participate as dispatchable resources

		(IEA 2014; Lew et al. 2011). Examples: Xcel Energy, U.S. RTOs/ISOs (Porter et al. 2012).
Location specificity	Generation is more economical where highest-quality resources are available.	Competitive Renewable Energy Zones in Texas are an example of an approach to quickly develop generation and transmission in coordination (18.5 GW and 3,600 miles were completed nine years after Competitive Renewable Energy Zones legislation was signed) to access wind resources in remote parts of the state.
Non-synchronous generation	Generators provide voltage support and frequency control in a different manner than traditional resources.	Grid code requirements are evolving in response to technological advances and anticipation of high VRE penetration levels. For example, ERCOT, which is a small interconnection and more vulnerable to frequency excursions, now requires wind generators to provide inertial response, which helps keep a system stable in the initial moments after a disturbance (Bird, Cochran, and Wang 2014).
Low capacity factor	Availability of the underlying energy resource limits the run-time of the plant.	Capacity payments or markets, potentially tied to performance, could ensure sufficient cost recovery. The potential for stranded assets is not unique to VRE and can occur whenever generation with lower marginal costs is added to the system. For example, low natural gas prices have reduced the market competitiveness of nuclear plants, contributing to recent retirements (Wernau and Richards 2014).

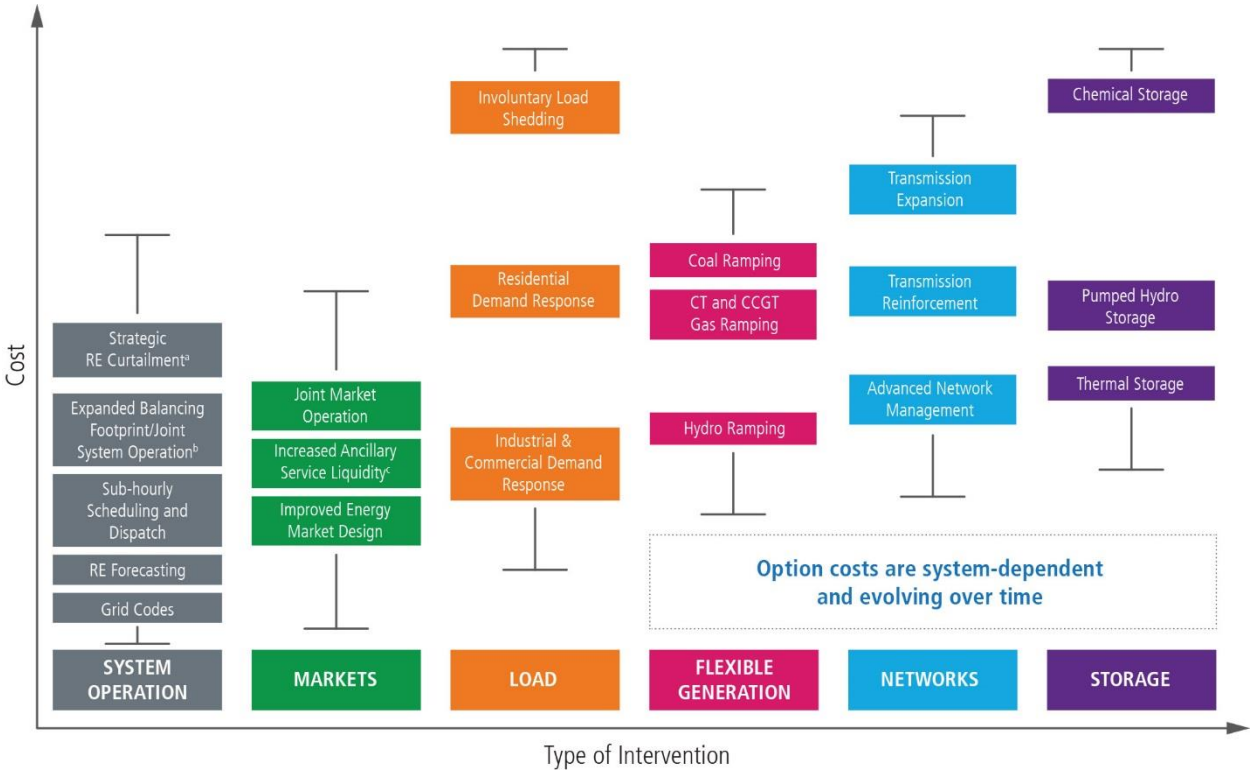
Utility-scale wind and solar plants are more location-limited than some other generation types, so they may require transmission construction to be able to interconnect with the grid and secure deliverability to customer load centers. LBNL researchers state that power systems with large or growing amounts of VRE:

> [W]ill benefit if the rest of the electricity system is flexible – able to respond to shifts in demand and VRE availability. VRE impacts and system costs will be driven lower as power systems transform to manage the unique characteristics that VRE resources introduce. Power systems that resist change as VRE penetrations increase will experience greater challenges in maintaining reliability and managing costs.[280]

Figure 4.9 shows a suite of options for integrating VRE effectively, spanning physical, operational, markets, load, and other means.[hhh]

[hhh] However, proponents of dispatchable renewables (biomass, hydro, and geothermal) argue that other approaches should also be considered. http://www.sciencedirect.com/science/article/pii/S1040619015000024X

Figure 4.9. Ways To Integrate VRE, Arrayed by Type of Intervention and Cost (2014)[281]



Forecasting of VRE is a critical challenge to system operators to manage high-risk weather days. Specific issues include wind icing forecasts and weather fronts that result in low-level jet winds and other wind cut-out scenarios. Since long-term VRE forecasting is not practicable today, system operators will have to rethink outage scheduling if a region has high dependency on wind as a resource.[282]

FERC, NERC, and the RTO/ISOs have undertaken several initiatives to modify requirements for interconnecting VRE to improve grid reliability. These initiatives include early work to develop low-voltage ride-through requirements for interconnecting wind and solar generation (which are included as a requirement for wind plant interconnection under the FERC open access transmission tariff), as well as California updating its solar photovoltaic (PV) distribution interconnection requirements to include smart inverters. Other nations have grid codes that require the provision of specific ERS for new VRE resources as a condition of interconnection. And FERC and several RTOs and ISOs have sought to remove barriers to participation in organized markets by DR resources that can deliver some ERS and provide benefits to consumers.

The Bonneville Power Administration (BPA) offers a good example of managing the challenges of integrating VRE effectively using better operational and business practices. Wind generation capacity in BPA's balancing authority area grew from 250 MW to 4,782 MW within a 10-year span, driven by state RPS requirements and Federal tax credits. Much of the wind generation is located along the Columbia River Gorge, connecting to the high-voltage transmission system serving the Federal Columbia River hydroelectric plants, so the wind fleet had little diversity and could swing output as much as 1,000 MW within an hour. BPA began charging for using hydropower to balance the wind generation (also called a balancing capacity rate and since adopted by FERC for other regions), and it set a penalty rate to encourage accurate wind production scheduling. Wind forecasting and scheduling practices and tools have since improved significantly.[283]

Because wind generation receives the PTC and has PPAs that encourage production regardless of system demand, it can be economical for wind to generate even when market prices are negative. As a result, generators that are "must-run" (either for statutory or reliability reasons) must compete with resources that will generate when prices are negative. Anticipating the growing challenges posed by the changing resource mix in the region, BPA worked with stakeholders to develop the Oversupply Management Protocol to displace generation in BPA's balancing authority area and replace it with Federal hydroelectric generation that must run for endangered fish operations. Displaced generators are compensated for any costs that they incur, and BPA recovers these costs through rates to its wholesale customers.[284]

However, this over-supply situation combined with sustained low natural gas prices has continued to erode the price of wholesale power in the western wholesale market. Changes in the wholesale market may be necessary to better balance state priorities, maintain grid reliabilities, and appropriately compensate baseload and other flexible resources, such as hydropower, for the ERS they provide.[285]

The process of BPS consolidation and market cooperation among producers across a larger electric market and operational region has been shown to smooth out VRE output variability. MISO found that

> [T]here are significant benefits from the geographic diversity of wind generating facilities and the size of the MISO operating footprint. The large number of individual turbines and plants, spread across a large geographic area with dimensions in the hundreds of miles, results in statistical smoothing of production changes driven by local meteorological effects. Large changes in aggregate production are driven by large-scale meteorological phenomena such as weather fronts, and occur over longer timescales from many tens of minutes to several hours.[286]

4.1.6 Impact of VRE on Net Load

More than 60 percent of all utility-scale electric generating capacity that came online in 2016 was from wind and solar technologies.[287] In March 2017, wind and solar accounted for 10 percent of total U.S. electricity generation, up from 7 percent for the whole of 2016.[288] The increase in VRE has altered grid operation in some regions and the way dispatchable generation and DR are used to protect the grid and meet loads.

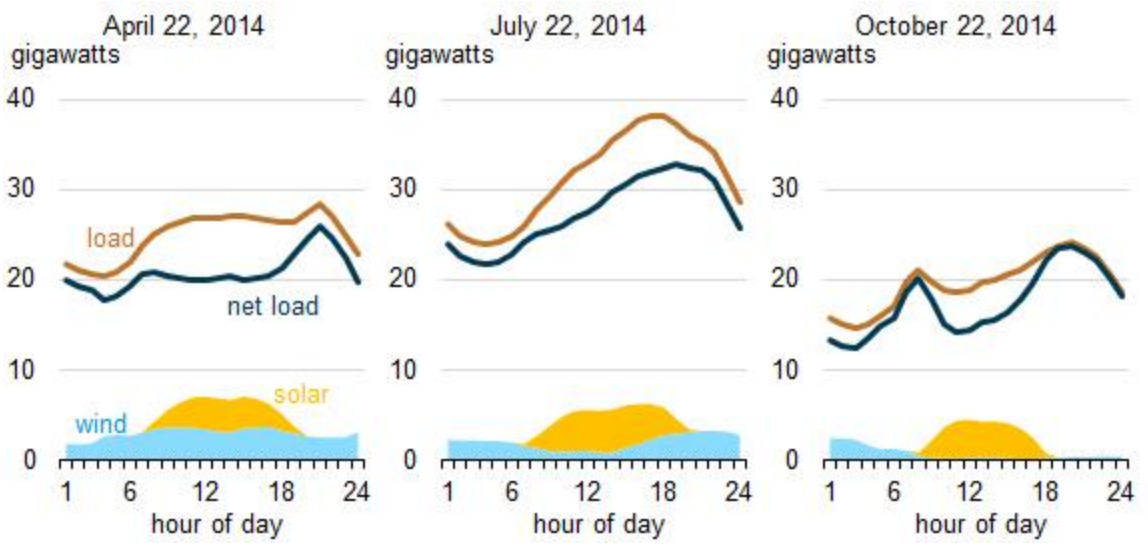
The Western Area Power Administration (WAPA), a Federal power marketing agency, operates 8,000 MW of hydroelectric generation and three balancing areas in 15 states across the West. WAPA sums up the operational changes and challenges for grid managers facing VRE, variable loads, and a variety of generation types with differing capabilities and constraints:

> Generation operators, including VERs [Variable Energy Resources], must coordinate with their host Balancing Authority (BA) to ensure that their output continuously matches load. Generation is adjusted throughout the day to meet scheduled output and is made available to regulate moment variations intra-hour. For VERs when the wind drops off or clouds pass over a solar array, less energy may be produced than scheduled (over-scheduled/under-produced), and additional resources must be brought on-line to make up the difference. There is a cost associated to these added generation resources. Similarly, if VERs are producing more than what was scheduled, or if electrical demand is less than anticipated, other resources must be backed down to ensure resources and load are balanced. Not all generation is capable of responding. Traditional generation, like coal, is not capable of reacting quickly to changing needs and takes hours or days to reach full operating potential. Gas turbines can react fairly quickly, but only if the plants are not already producing at full rated generating capacity. Hydro generation, while being an ideal resource to help with VER

integration, is generally scheduled to meet reservoir requirements or provide for downstream water demands, including fish, wildlife, and other environmental mitigation requirements.[289]

To illustrate how VRE can increase the need for flexibility, Figure 4.10 demonstrates how VRE impacts system operations. The figure introduces the concept of "net load"—electricity demand minus VRE generation—which represents the demand that must be supplied by the conventional generation fleet if all VRE is to be utilized. The dark orange line in the graph represents total demand and shows the daily variability of demand on an hourly basis. The light blue area shows wind energy, and the yellow area shows solar energy. The dark blue line represents the demand (less VRE) that must be supplied by the remaining generators, assuming no curtailment of wind energy. The graph shows that often the output level of the remaining generators must change more quickly and be turned up or down inversely with VRE production.

Figure 4.10. CAISO Load, Net Load, and Wind and Solar Output on Example Weekdays during 2014[290]

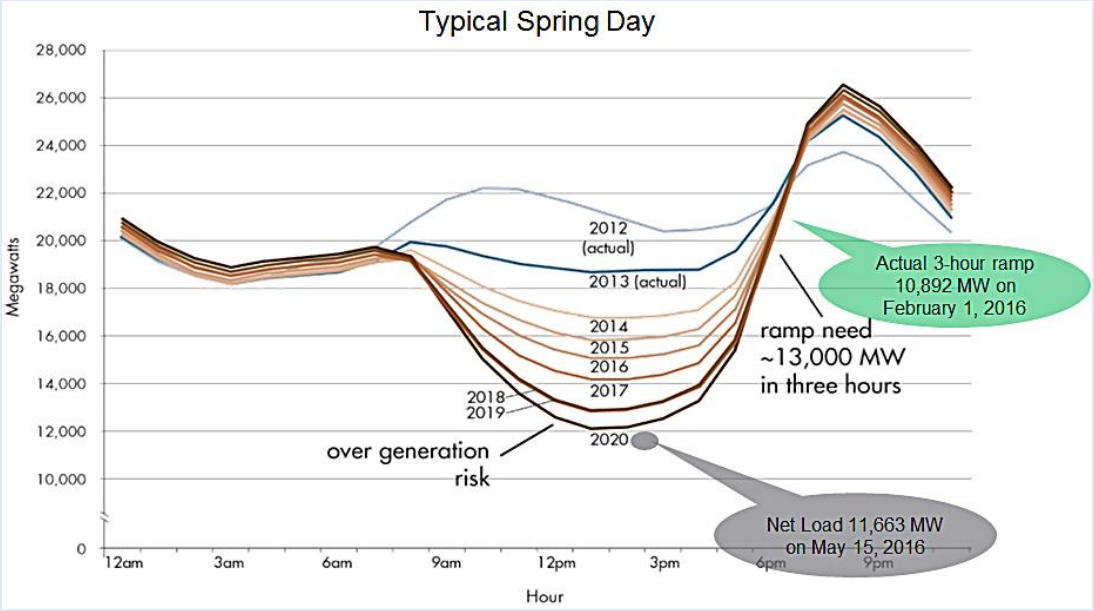


CAISO data show the effect of VRE on net load (total customer load minus wind and solar output) during representative days in the spring, summer, and fall. As the amount of VRE generation increases, daily net load decreases, and the impacts on net load become more acute in shoulder months.

In regions with high penetration of VRE, sharper fluctuations in net load require increased flexibility (ramping up and down) from conventional sources. While the resulting 'duck curve' of daily net load has so far been limited to regions such as California and the Southwest where solar generation is highest, other regions such as the Carolinas are beginning to see similar net load patterns.[291]

What the Duck Curve Tells Us About Managing a Green Grid[292]

Figure 4.11. The CAISO Duck Curve



The electric grid and the requirements to manage it are changing… The ISO created future scenarios of net load curves to illustrate these changing conditions. Net load is the difference between forecasted load and expected electricity production from variable generation resources. In certain times of the year, these curves produce a 'belly' appearance in the mid-afternoon that quickly ramps up to produce an "arch" similar to the neck of a duck — hence the industry moniker of 'The Duck Chart.'

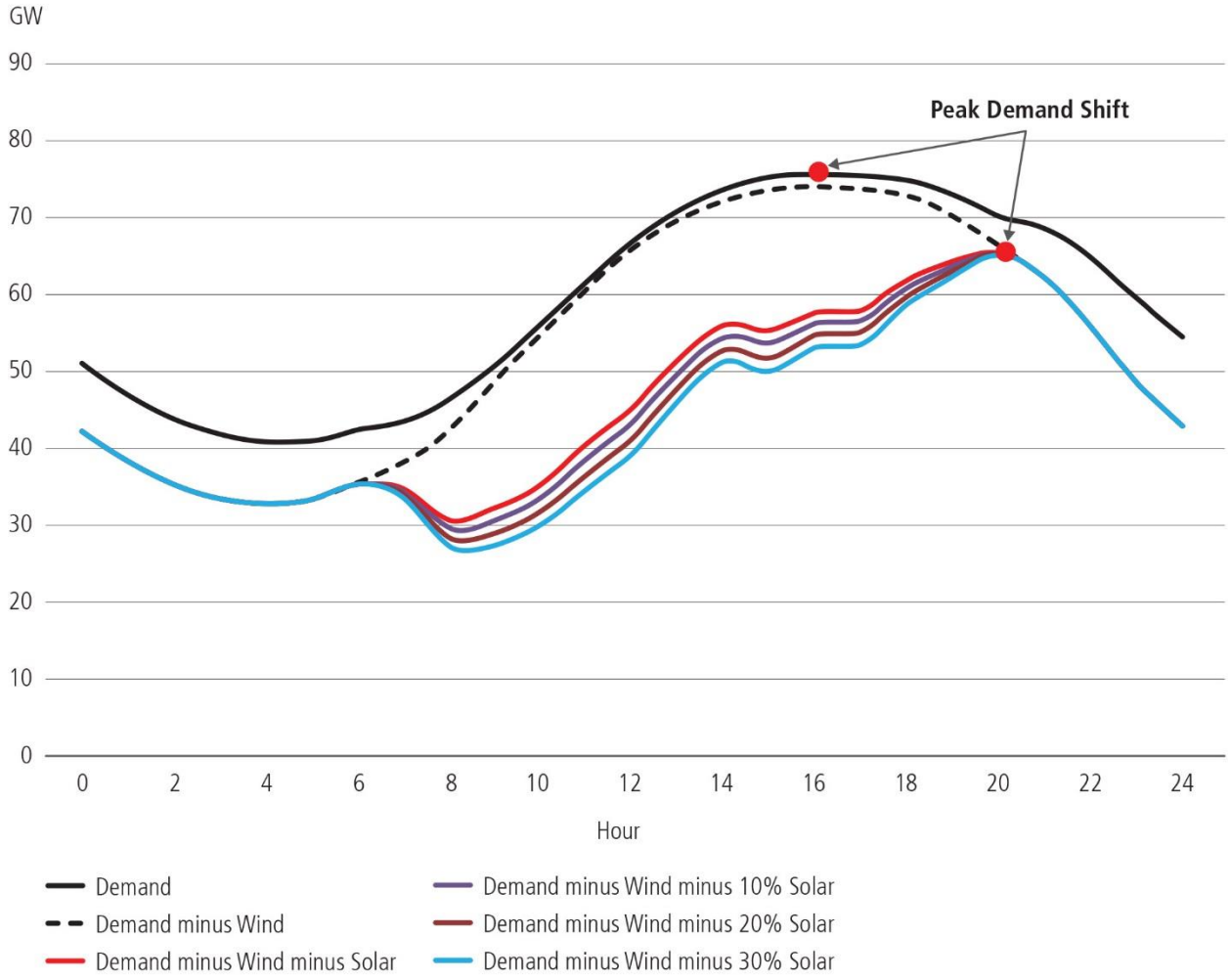
…[S]everal conditions emerge that will require specific operational capabilities:

- Short-steep ramps – when the ISO must bring on or shut down generation resources to meet an increasing or decreasing electricity demand quickly, over a short period of time;
- Oversupply risk – when more electricity is supplied than is needed to satisfy real-time electricity requirements; and
- Decreased frequency response – when less resources are operating and available to automatically adjust electricity production to maintain grid reliability."

[…] To ensure reliability under changing grid conditions, the ISO needs resources with ramping flexibility and the ability to start and stop multiple times per day […] Addressing concerns about frequency response capabilities in times of low load and high renewable generation may require operating renewable generators such that they can increase power with automated frequency response capability.

At some level of penetration of distributed PV, the collective amount of PV will shift the time of peak load net of solar generation away from its previous point to later in the evening when insolation (and therefore PV production) is lower, as shown by NERC in Figure 4.12.

Figure 4.12. Demand and Net Demand Shapes at Different Distributed Energy Resource Penetration Levels[293]



To date, RTOs and ISOs are working hard to integrate growing levels of VRE through extensive study, deliberate planning, and careful operations and adjustments.

The Role of Technical Standards and Grid Codes for Effective VRE Integration

Several types of standards apply to VRE and other generation. Interoperability standards define basic technical and engineering performance requirements, such as the Institute of Electrical and Electronics Engineers Standard 1547, which defines uniform requirements for the performance, operation, testing, safety, and maintenance of interconnection between distributed generation resources and the grid. Regulatory requirements such as FERC's *pro forma* open access transmission tariff (including interconnection requirements) dictate further reliability and performance terms for generators. As the level of installed wind and solar generation has grown, early technical requirements and standards for wind and solar have required updates to ensure performance under disturbance conditions.

The examples described below illustrate the need to evolve standards as the penetration of non-synchronous generation increases.

- In August 2016, the Blue Cut wildfire crossed a major transmission corridor in Southern California, resulting in 15 line faults. One of these faults caused the near-instantaneous loss of

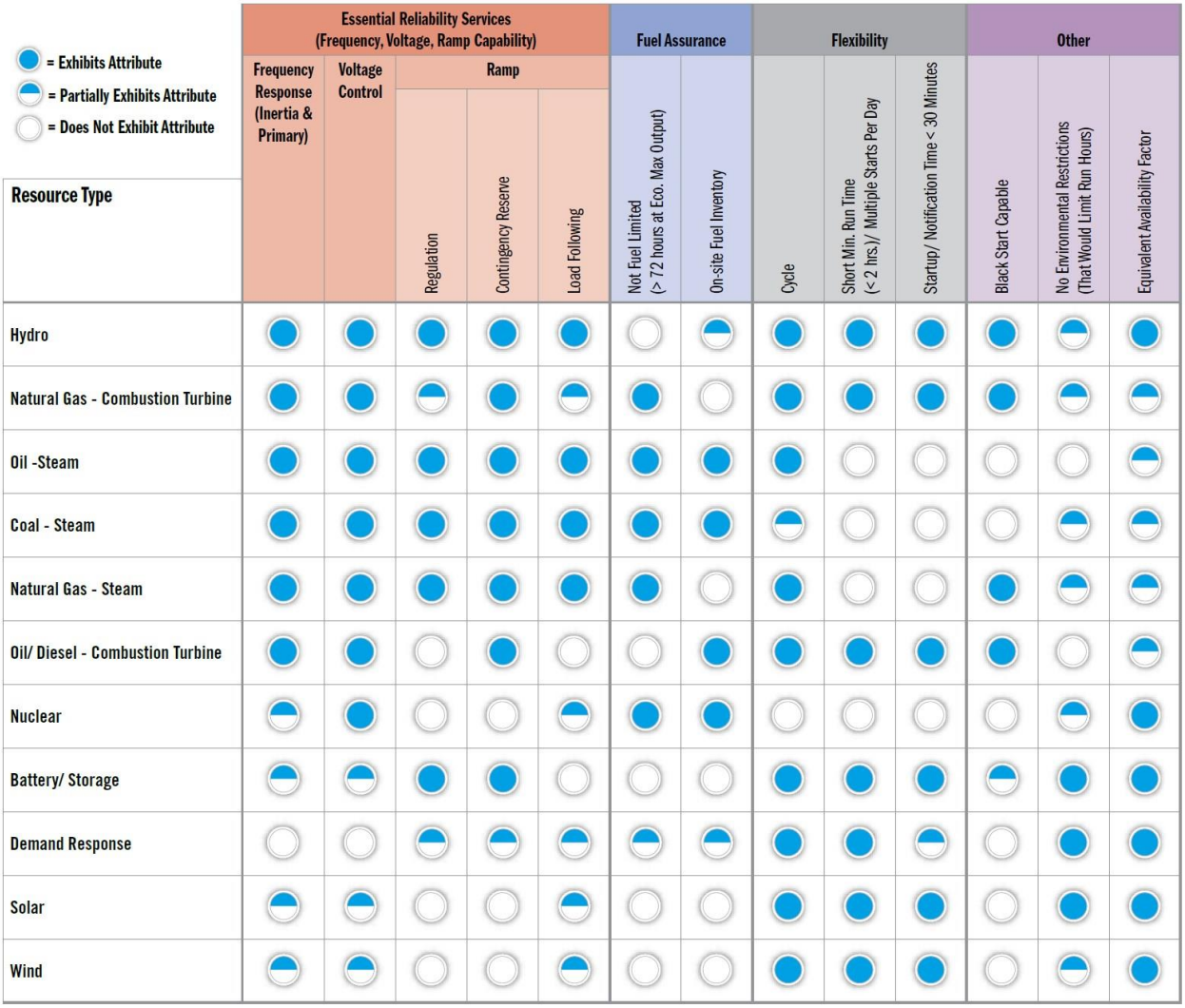
1,200 MW of utility-scale PV in Southern California. Approximately 700 MW of this loss occurred when PV inverters tripped due to a "perceived, though incorrect, low system frequency condition."[294] Another 450 MW of this loss occurred when system voltage fell below the low-voltage ride-through setting of the inverters—resulting in "momentary cessation."[295] The subsequent NERC disturbance report determined that 11 similar inverter events occurred between August 16, 2017 and February 6, 2017, and NERC made several recommendations with respect to inverter settings and standards that would prevent or mitigate these events.[296]

- Australia's Renewable Energy Target has achieved significant VRE use; 35 percent of South Australia's generating capacity is wind-powered. On September 28, 2016, severe weather resulted in multiple faults on the South Australian transmission system. A number of faults in quick succession caused 456 MW of wind generation to trip off-line within approximately seven seconds as a result of a protection feature that disconnects or reduces wind turbine output when the number of low-voltage ride-through events in a specific time period exceeds a predefined limit.[297] This loss of generation increased imports from the AC interconnector until protective relays activated, islanding South Australia. Unable to rapidly shed load to match the reduced supply, the islanded region experienced a blackout. The Australian Energy Market Operator's report on the incident noted the role of changes in the fuel mix: a low amount of synchronous generation dispatched—and hence low inertia—at the time of the event resulted in a faster frequency change than had previously been experienced during separation events.[298] The report produced a list of 19 recommendations, including changes to operating procedures, regulations, and performance standards.
- The German *Energiewende* initiative encouraged high levels of wind and distribution-level solar installations, leading to over-generation and the need for VRE' curtailment in some hours. The grid technical code in place at the time required PV inverters to immediately disconnect from the grid if system frequency increased from nominal 50 Hz to 50.2 Hz. However, Germany discovered that the combination of this technical code and the growing amount of distribution-level PV capacity heightened the risk of some excess PV generation causing all PV capacity to disconnect simultaneously and create severe under-frequency conditions, potentially causing rolling blackouts and grid collapse.[299] In response, Germany modified its standards to require inverter retrofits with different low-frequency performance requirements.[300]

4.1.7 Mapping Reliability Attributes to Generation Resources

To assess its changing resource mix, PJM developed a matrix of reliability attributes needed to maintain reliable grid operation under its operating procedures (see Figure 4.13). Ultimately, a diverse generation portfolio is necessary to provide the reliability attributes discussed in this section.

Figure 4.13. Mapping Reliability Attributes Against Resources[iii] [301]



Conventional generation sources—particularly hydroelectricity, combustion turbines (natural gas and oil), and steam turbines (oil, coal, and natural gas)—performed very well against most of PJM's reliability requirements. Nuclear units are not optimized for significant flexibility or ramping capability, but do exhibit strong fuel assurance[jjj] attributes. Batteries and storage meet all flexibility requirements, and DR offers high flexibility and ramping management capability. Wind and solar are highly time dependent and do not offer fuel assurance on their own, but can offer good flexibility if they have the proper controls and contractual arrangements.

The Electric Power Research Institute (EPRI) summarizes how regional grid operators use centrally-organized markets to procure specific reliability attributes from generators:

[iii] Combined-cycle plants are included in the Natural Gas – Steam group.

[jjj] Fuel assurance is the resource portfolio's ability to access sufficient fuel to meet system needs and maintain reliability; aspects of fuel assurance include onsite fuel storage, as well as a generator's access to sufficient fuel supplies through markets or bilateral contracts.

Ancillary Services in Centrally-Organized Markets[302]

… [E]ach ISO also operates auction markets for spinning, non-spinning reserves, and regulation with uniform clearing prices, with additional performance payments for regulation. (ERCOT, however, does not offer performance payments). Table 2 [Figure 4.14 on the following page] presents some of the terminology and characteristics. The hourly requirements for these services are set based on reliability standards and operational requirements that vary by ISO. The market designs generally co-optimize energy and reserves. Although ancillary service market designs can be complicated, the level of procurement typically only comprises less than 2% of total market volume. Ancillary service pricing is also used to signal short-term supply shortages. Because procurement of these ancillary services is allowed to be deficient before load is curtailed, the failure to procure sufficient reserves is often a first indicator of supply shortage. Hence, the ISOs include administrative scarcity prices in the market designs. Such pricing allows ancillary service prices—along with energy prices, when opportunity costs are included—to increase during shortages to levels more consistent with the value of lost load than the energy market offer caps. These scarcity prices are established differently in each ISO.

There are a number of recent initiatives to modify the ancillary service markets. CAISO and MISO have recently implemented types of ramping reserves, intended to increase the ramping range from committed resources available during real-time energy dispatch. Some ISOs, notably ERCOT, have also begun to develop designs for frequency-responsive and inertial response reserve markets.

Two ancillary services—voltage support/reactive power and black start services—are not yet considered to have the appropriate characteristics for competitive markets and are thus compensated through cost-based rates.

Figure 4.14 Selected Ancillary Service Market Design Characteristics

	ISO-NE	NYISO	PJM	MISO	SPP	ERCOT	CAISO
Regulation							
Product name	Regulation	Regulation	Regulation	Regulation	Regulation up, Regulation down	Regulation service	Regulation up, Regulation down
Performance component name (details in Table 3-12)	Regulation service	Regulation movement	Regulation performance	Regulating mileage	Regulation-up mileage, Regulation-down mileage	N/A	Regulation mileage up Regulation mileage down
Day-ahead procurement		✓		✓	✓	✓	✓
Real-time procurement	✓	✓	✓	✓	✓		✓
Contingency Reserves							
Product name—spinning reserve	Ten-minute spinning reserve (TMSR)	Spinning reserve	SR	Spinning reserve	Spinning reserve	Responsive reserve	Spinning reserve
Product name—non-spinning reserve and supplemental reserve	Ten-minute non-spinning reserve (TMNSR); Thirty-minute operating reserve (TMOR)	Non-spinning reserve	Non-synchronized reserve (NSR)	Supplemental reserve	Supplemental reserve	Non-spinning reserve	Non-spinning reserve
Forward (pre-day-ahead) procurement	✓						
Day-ahead procurement		✓	*	✓	✓	✓	✓
Real-time procurement	✓	✓	✓	✓	✓		✓

Continued on next page

Figure 4.15. Ancillary Service Products Exchanged in the Centrally Organized Markets, Listed by RTO/ISO and Category of Ancillary Service

	ISO-NE	NYISO	PJM	MISO	SPP	ERCOT	CAISO
Product name—ramp reserve				Ramp capability			Flexible ramping product
Ramp reserve—when procured				DAM and RTM			FMM and RTM (not DAM)
Voltage control—payment mechanism provision and capability	Lost opportunity cost and American Electric Power (AEP) method	Lost opportunity cost and fixed tariff rate	Lost opportunity cost and AEP method	Lost opportunity cost and AEP method	Compensation rate for provision	Lost opportunity cost for provision	Provision payment based on lost opportunity cost or contract
Black start service payments	Paid standard black start rate or station-specific rate	Paid cost-based rates	Receive revenue based on 110% of annual black start costs	Receive cost-based rate after committing to 3-year period	Not procured through SPP	Procured through bi-annual competitive process	Contracted through reliability contracts

Note: ("DAM" = day-ahead market; RTM = real-time market)

Several flexibility options are available to grid operators, such as DR, fast-ramping natural gas generation, and energy storage. As stated in QER 1.2:

> A recent study of the value of fast-ramping gas for supporting variable renewables noted that, '…to date FRF [fast ramping fossil] technologies have enabled RE [renewable energy] diffusion by providing reliable and dispatchable back-up capacity to hedge against variability of supply... renewables and fast-reacting fossil technologies appear as highly complementary and… should be jointly installed to meet the goals of cutting emissions and ensuring a stable supply.'[303]

In addition to existing sources of flexibility and reliability services, there is a growing understanding of the abilities of VRE to economically contribute to grid flexibility and reliability through operational changes and advanced power electronics. Recent technology advancements now enable wind plants to provide nearly the full spectrum of ERS (synthetic inertial control, primary frequency control, and automatic generation control). Similarly, for PV, CAISO, First Solar, and NREL recently demonstrated a First Solar 300 MW PV plant that provides active and reactive power controls, plant participation in automatic generation control, primary frequency control, ramp rate control, and voltage regulation.[304]

A recent NERC assessment on reliability in the BPS noted that DR can enhance system flexibility and reliability by providing, "regulation, governor response, spinning reserve, non-spinning reserve, and supplemental operating reserve[. F]or example, ERCOT obtains half of its spinning reserves from DR and is considering a DR-based Fast Frequency Response Service that is positioned between inertia and governor response."[305] Consumer end uses—including building energy management systems, as well as water and space heating and cooling—can also serve as DR resources using load control and communicating technologies to ramp their consumption up or down in order to support VRE integration.[306]

Demand-side flexibility via "smart charging" plug-in electric vehicles is another potential source of grid flexibility. This involves a utility or some other centralized entity remotely controlling the charging patterns of participating vehicles and/or charging stations. An aggregated fleet of vehicles or chargers can act as a DR resource, shifting load in response to price signals or operational needs; for example, vehicle charging could be shifted to the middle of the day to absorb high levels of solar generation and

shifted away from evening hours when solar generation disappears and system net load peaks. Research in this area is currently underway at the national laboratories.[307]

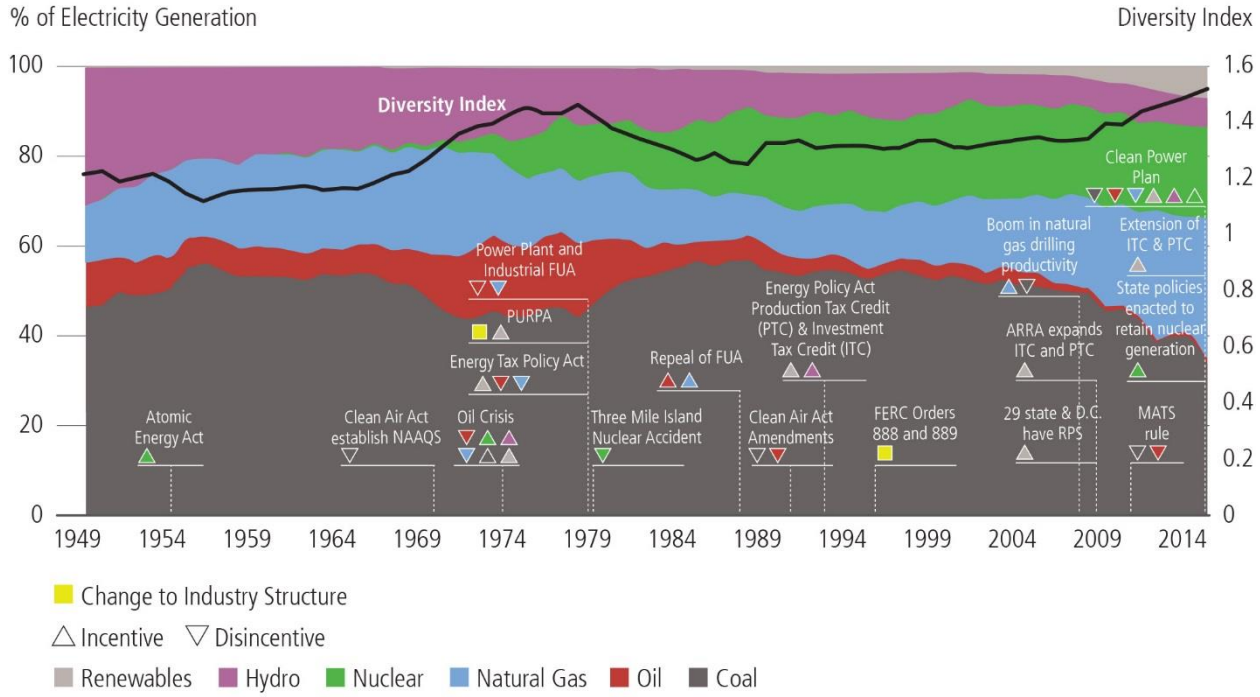
4.2 Diversity, Fuel Assurance, and Onsite Storage

The April 14 memo raises the questions of whether the diversity of the generation resources in the electric system has diminished and whether this is a problem for grid reliability and resilience. In fact, when looked at nationally, the electric system is more diverse today than it was 20 years ago, although increased national diversity does not necessarily mean diversity has increased in all regions. A holistic view of reliability and risk management, however, must include both diversity and fuel assurance.

4.2.1 Fuel Diversity

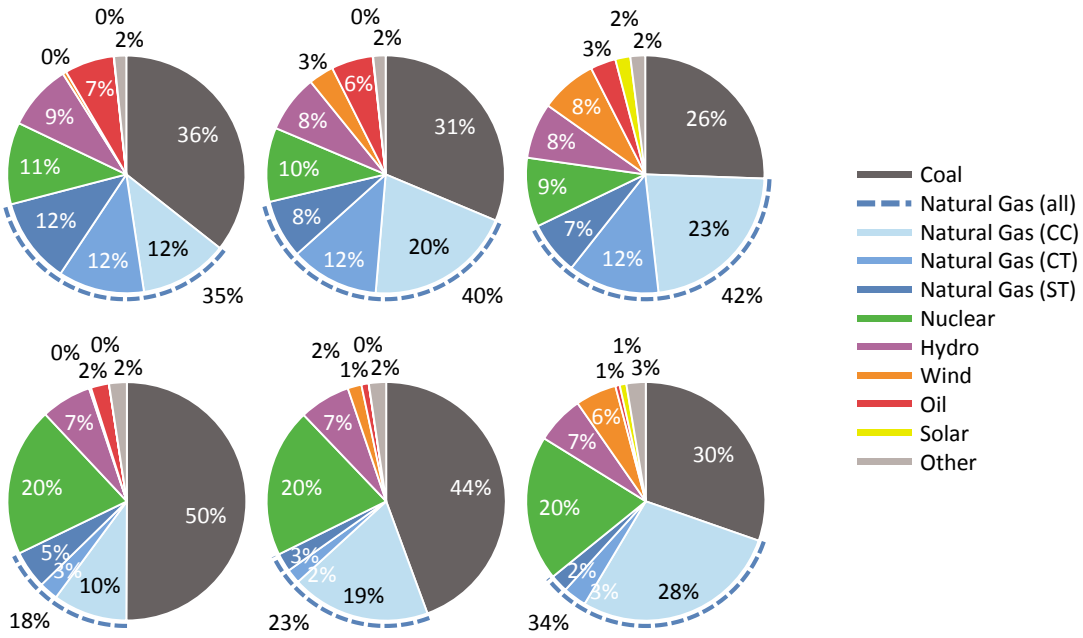
The U.S. generation mix has continually evolved as changes in technology, economics, government policy, and geopolitical forces affected the relative availability, economics, and feasibility of competing energy sources. PJM documents this evolution in Figure 4.16, which also displays a diversity index showing increasing diversity levels from about 2000 through 2014. PJM observes that, "government policy has played a major role in the development of generation resources, including policies that focused on energy security, jobs, environmental protection and conservation."[308] The chart shows how the mix of U.S. electricity use has moved in cycles for decades—how the generation share of hydroelectric facilities (most built with Federal funds during the 1930s and 1940s) declined as coal and natural gas grew (helped with funding from low-cost Federal land and mineral leases); how nuclear generation grew (aided by Federal policy and funding assistance) in the 1960s; how nuclear energy displaced hydroelectricity and natural gas-fired electricity in the 1970s; and how coal, nuclear, and natural gas-fired electricity have displaced oil-fired generation since the 1980s.

Figure 4.16. Generation Mix and Various Economic and Policy Drivers Since 1949, Including Diversity Index[309]



Closely tracking the PJM trends, the national picture of the resource mix shows coal and oil being displaced by gas and VRE. In addition to this, Figure 4.17 shows how the national U.S. capacity and generation mix have become more diverse over time. Changes in capacity (top) have moved the resource mix toward a greater proportion of natural gas, wind, and solar, while coal and oil capacity have decreased. Energy generation trends for these resources (bottom) have tracked changes in capacity, with natural gas generation almost doubling in proportion. While nuclear capacity has decreased relative to other resources, the proportion of nuclear generation remains unchanged as capacity factors for nuclear units have increased

Figure 4.17. Changes in U.S. Capacity (Top) and Generation (Bottom) Mix over Time (Left to Right: 2002, 2009, 2016)[310]



The grid was, on average, more diverse in 2016 than in 2002 in terms of both capacity and generation.

Diversity can be a useful tool for managing both reliability and financial risks. For the power system, developing and maintaining a portfolio of diverse generation, storage, and demand-side options can be useful for system planners and operators in creating optionality and hedging risks. Physical and financial risks can also be managed and hedged using reliability standards, operating rules, and financial markets and contracts. Better system diversity with greater use of domestic energy sources enhances U.S. energy security. However, greater fuel diversity does not *always* translate to increased system reliability.

Risk, Reliability, and Fuel Diversity[311]

In a summary of the policy implications of the impacts of fuel diversity on risk and reliability, Devin Hartman of the R Street Institute states that:

Policymakers and regulators should recognize that fuel diversity is a poor proxy for valid policy objectives, like risk management and reliability. Specifically, a high level of fuel diversity does not necessarily mean that an electricity system manages risk efficiently or meets reliability needs. Conversely, policies or market-design changes intended to increase fuel diversity will not necessarily improve risk management or reliability.

Fuel neutrality is essential for both monopoly-utility resource planning and competitive markets to manage risk and achieve reliability efficiently. Interventions to promote specific fuel types—such as

bailouts for coal and nuclear or mandates and subsidies for renewables—skew investment risk and can undermine incentives for reliability-enhancing behavior (e.g., a public intervention to finance pipeline expansion removes incentives for the private sector to invest in fuel security). Fuel-specific subsidies and mandates replace individual choice with collective choice. This one-size-fits-all approach to risk mitigation ignores variances in individuals' risk tolerances, results in high-cost risk mitigation, and creates perverse incentives for market participants by transferring risk and costs from the private to the public sector.

For regulators, attempts to achieve fuel diversity in market designs explicitly would likely result in inefficient and potentially discriminatory practices that are inconsistent with the Federal Power Act. The reliable performance of power generators varies across and within fuel types and changes with fluctuating conditions. This renders any attempt to value fuel diversity very complex. It would require extensive administrative judgment, expanding the potential for government failure. Ultimately, the central aim of market design should remain to procure specific reliability attributes at the least cost.

4.2.2 Fuel Assurance and Onsite Storage

FERC uses the term fuel assurance to mean a generator's access to sufficient fuel supplies through markets or bilateral contracts (and the degree to which those arrangements are firm). On the RTO/ISO level, fuel assurance refers to the regional resource portfolio's ability to access sufficient fuel to meet system needs and maintain reliability.[312] [313]

NERC's 2017 *State of Reliability* report identified "lack of fuel" among the top ten causes of forced outages for 2014 and 2015.[314] While lack of fuel is a relatively infrequent cause of generator outages, it can still have major repercussions when it does occur because system fuel supply chain disruptions can impact many generators during a single widespread fuel shortage event. Nuclear and coal plants typically have advantages associated with onsite fuel storage compared to natural gas. While having fuel onsite reduces the risk that a generator will be unable to operate when needed, every type of fuel and power generation source has known vulnerabilities that can compromise its ability to perform reliably.

Valuation or regulation of onsite fuel storage varies across the Nation's organized markets. Onsite fuel supplies can be required, incentivized, or not compensated—depending on the RTO/ISO in question. For example, some dual-fuel generators in the New York City region (NYISO Zone J) are required under local reliability rules to maintain onsite fuel to protect against the loss of gas supplies.[315] Several markets have also attempted to incentivize firm and onsite fuel supplies by adding performance requirements to their capacity markets. In PJM and ISO-NE, these requirements were adopted after generator underperformance occurred during several instances of system stress between 2010 and 2014.[kkk] The incentives in these markets are designed to reward or penalize generators based upon how they respond to the system operator during performance events.

According to Gordon van Welie, President and CEO of ISO-NE:

> We currently have a precarious operating situation in the winter time and we're worried about it becoming unsustainable beyond 2019… The reality is that we're really operating with a very slim operating margin during the winter time that may not cover these large contingencies that worry us.[316]

[kkk] These events included both situations in which natural gas power plants were unable to draw fuel from pipelines, as well as ones in which sufficient fuel was available but unit outages and/or start times inhibited operation.

Both programs remain in their infancy: ISO-NE's takes effect in 2018, and PJM's has only been active since 2016 (with a gradual phase-in through the 2019/2020 delivery year). In the interim, ISO-NE instituted a stopgap measure called the Winter Reliability Program, which compensates some dual-fuel generators for procuring onsite fuel.[317] Outside of these regions, onsite fuel is not compensated or, in the case of VIEU, is incorporated into integrated resource planning (IRP) efforts. Other aspects of fuel assurance include having dual fuel capabilities and having low exposure to supply chain interruptions (including adequate, reliable infrastructure and sufficient contractual arrangements for fuel delivery).

Natural Gas

NERC refers to the "single point of disruption risk" as the increasing risk of fuel disruption that threatens generator availability. In a letter to Secretary Perry, NERC CEO Gerry Cauley observed that:

> Growing reliance on natural gas continues to raise reliability concerns regarding the ability of both gas and electric infrastructures to maintain the BPS reliability at acceptable levels. Many efforts have focused on the gas-electric interface and yet, insufficient progress has been made reconciling the planning approaches and operating practices (scheduling situation awareness, information sharing) between these two inter-linked sectors. Planning approaches, operational coordination, and regulatory partnerships are needed to assure fuel deliverability, availability, security (physical and cyber), and resilience to potential disruptions. Unfortunately, an approach not obvious in electricity markets today.[318]

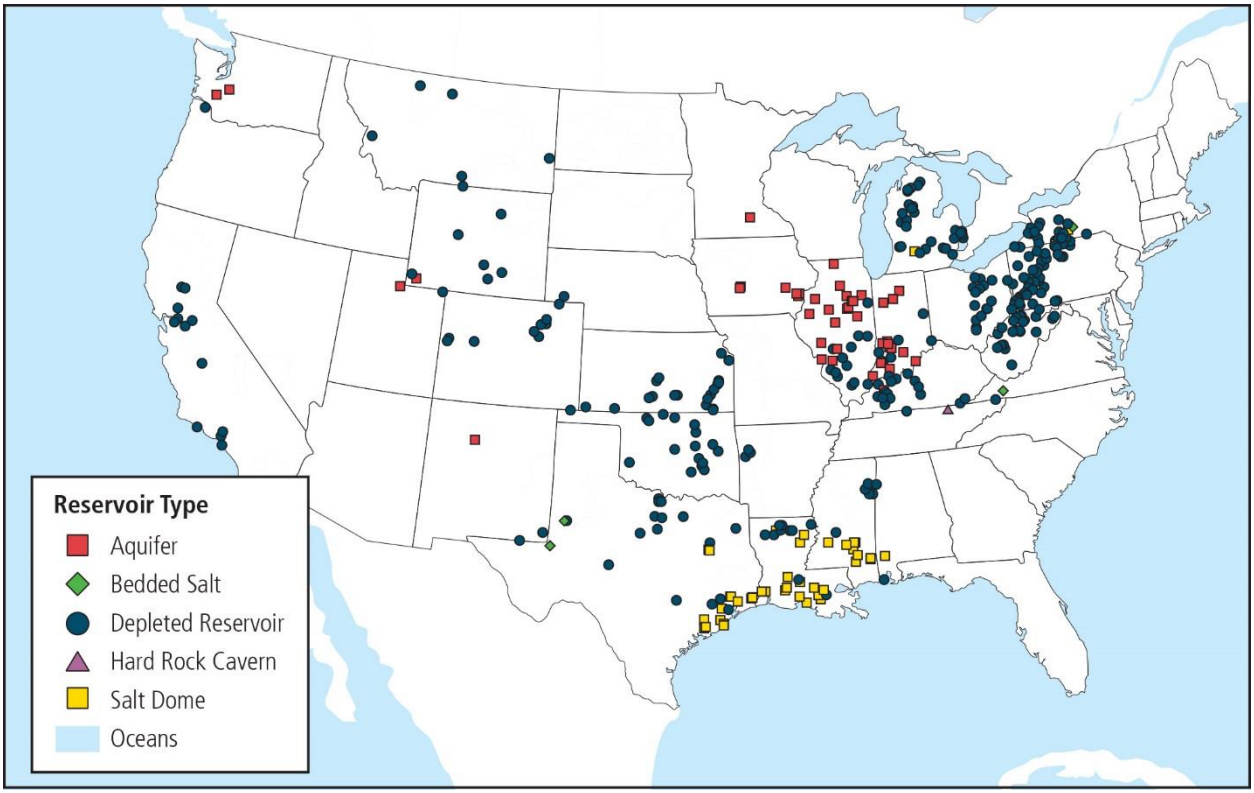
Natural gas-fired generators have been described as relying on "just-in-time" fuel delivery.[319] NERC, FERC, and several of the ISOs and RTOs have studied the gas-electric interactions and interdependence, which are most severe in the areas where natural gas generation is growing most quickly, but natural gas pipeline infrastructure is more constrained—particularly New England and California. NERC has concluded that:

> […] areas with a growing reliance on natural gas-fired generation are increasingly vulnerable to issues related to gas supply unavailability. Common-mode, single contingency-type disruptions to fuel supply and deliverability in areas with a high penetration of natural gas-fired generation are reducing resource adequacy and potentially introducing localized risks to reliability. Not only can impacts to BPS reliability occur during the gas-load peaking winter season, but they can also manifest during the summer season when electric demand is high and natural gas facilities are out of service, which can lower the operational capacity and flow of the pipeline system.[320]

NERC recommends a number of planning and operational changes to address this challenge, including risk-based approaches to study the potential regional reliability implications of greater natural gas dependence; the potential for wide-spread, common-mode failure events such as interstate gas pipeline or supply source losses; regional mitigation strategies; better information-sharing and coordination between electric generators, gas suppliers, and pipeline operators; and ensuring the availability of more flexible resources for use to mitigate the added uncertainties associated with natural gas fuel risks.[321]

Natural gas storage is a way to reduce the just-in-time delivery problem. Natural gas is stored in depleted natural gas and oil fields, depleted natural aquifers, and salt caverns. Figure 4.18 shows natural gas storage facilities across the Nation. The ideal storage facilities are near major gas consumption centers, where storage can supplement gas pipelines to meet high demand levels and fill in deliveries in the event of any delivery disruptions.

Figure 4.18. Natural Gas Storage Facilities[322]



The United States has over 400 natural gas storage facilities; the majority are depleted natural gas fields used for storage, with salt domes concentrated in the Southeast and aquifer storage concentrated in Illinois and Indiana.

Data presented at a recent testimony before FERC offers an interesting perspective on areas that depend on just-in-time energy. The data in Table 4-3 show a dozen states that depend on high levels of just-in-time imports, whether those imports are natural gas for in-area generation or transmission-enabled electricity imports. These areas may need greater planning and resilience measures to ensure fuel security, which may include some availability of petroleum-based fuels for units that can use them when natural gas may be difficult or expensive to source.

Table 4-3. Dependence on Imported Just-in-Time Energy for Electricity[323]

Risk Rank	State	Electricity Consumed in 2015 (GW Hour)	Net Electricity Imports (Exports)	Electricity Generation Using Imported Natural Gas	Total Imported Energy for Electricity
1	Washington DC	12,099	100%	0%	100%
2	Rhode Island	8,200	15%	80%	96%
3	Delaware	13,016	40%	51%	91%
4	Massachusetts	59,367	46%	35%	81%
5	Nevada	38,479	-1%	75%	74%
6	California	289,703	32%	36%	68%
7	Florida	256,344	7%	61%	68%
8	Vermont	5,885	66%	0%	66%
9	New Jersey	81,931	9%	45%	54%
10	Maryland	66,596	45%	7%	52%
11	Virginia	122,050	31%	20%	51%
12	New York	160,285	14%	35%	49%

The leaks discovered at California's Aliso Canyon natural gas storage facility in October 2015 California illustrate another natural gas common failure mode problem, according to analysis completed by PJM:

> Analysis performed after the leak identified 17 nearby electric generators with a combined output of over 9,800 MW that relied on Aliso Canyon for fuel supply. Some of these generators are required for local reliability; however, without supply from Aliso Canyon, low pressure in gas pipelines could stop the flow of gas to the generators, leaving them unable to operate.[324] The loss of Aliso Canyon gas storage field highlights the risk to the power grid from failures in the pipeline infrastructure. Electric market and regulatory changes in California resulting from this event include: expedited procurement of electric storage resources, enhanced gas-electric coordination, expanded demand response program and a constraint in the electric market that reflects gas limitations.[325]

After the 2014 Polar Vortex, when many gas-fired power plants were forced off-line due to natural gas production and delivery problems, inadequate gas supply contracts, and spiked natural gas prices, NERC recommended the following:

> Examine and review the natural gas supply issues encountered during the event. Industry should also work with gas suppliers, markets, and regulators to quickly identify issues with natural gas supply and transportation so that appropriate actions can be developed and implemented to allow generators to be able to secure firm supply and transportation at a reasonable rate.[326]

FERC has since promulgated orders to improve coordination between natural gas and power industry operations. While various electric and gas industry groups, including NERC, have had and continue coordination efforts, a significant amount of coordination remains unresolved.

Nuclear

As NERC noted, low exposure to fuel supply issues is one of the fundamental necessities of a reliable BPS. Still, fuel availability does not always guarantee dependable performance, particularly during extreme weather events. In 2010, the Browns Ferry nuclear plant in Alabama was throttled back to 50 percent of its maximum output because the plant was unable to draw and return enough water (due to environmental regulations) to cool all three of its reactors.[327]

Nuclear generators have onsite fuel storage due to their 18-month or 24-month refueling cycles.[328] During the Polar Vortex, some coal and nuclear plants had fuel onsite but failed to perform nonetheless. However, overall nuclear generators performed extremely well during the Polar Vortex, with an average capacity factor of 95 percent.[329]

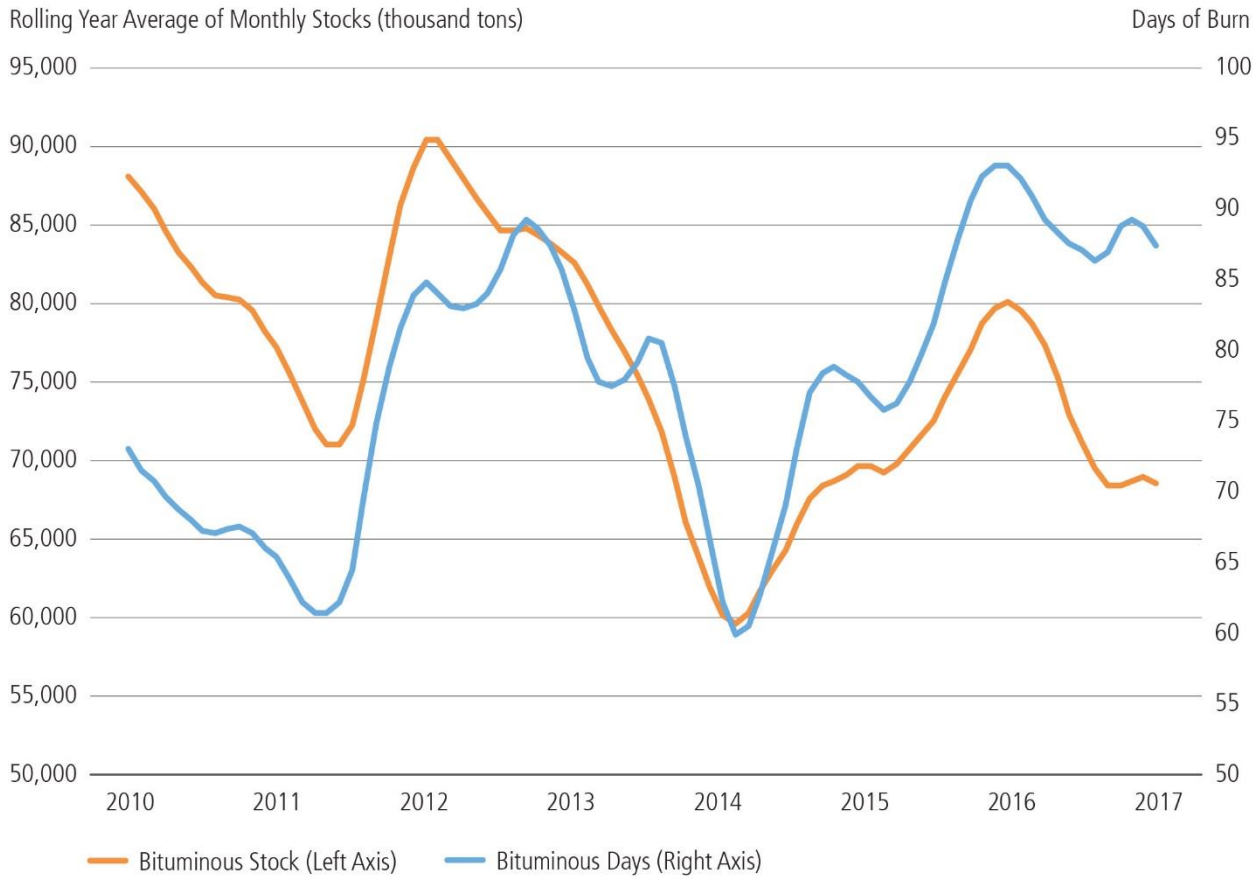
Nuclear power plants tend to have a very high number of "days of burn" onsite relative to coal, as their refueling occurs in 18-month or 24-month cycles. During each refueling, about one-third of the core is replaced with new fuel. The new fuel arrives onsite between nine and five weeks prior to the planned refueling. However, even if there is a delay in the arrival of new fuel, the reactor could continue to operate for an additional three months before reaching 70 percent capacity and two more months beyond that (for a total of five months) before decreasing to 50 percent capacity. The fuel that is replaced during each refueling has typically been used in the reactor for four-and-a-half to six years before it is removed. Planned refueling outages are typically scheduled for the spring and fall and average 35 days.[330]

Coal

A limited number of coal plants, including all plants that use lignite coal, are "mine-mouth" facilities that rely on dedicated, nearby coal mines. Otherwise, coal plants rely on rail, barge, or truck delivery of coal, and they maintain onsite coal stockpiles to accommodate both normal variance in deliveries and the possibility of a major supply disruption. Coal stockpiles have recently been slightly smaller than historical averages, while days of burn have increased slightly relative to historic averages from the 70–80-day range to the 85–100-day range (see Figure 4.19).[III] [331]

[III] At an individual plant, stockpiles can be viewed in terms of days of burn. The days-of-burn calculation considers both the current stockpile level at a plant and its estimated consumption (burn) rates in coming months to approximate how many days the plant could run at historical levels before depleting its existing stockpile.

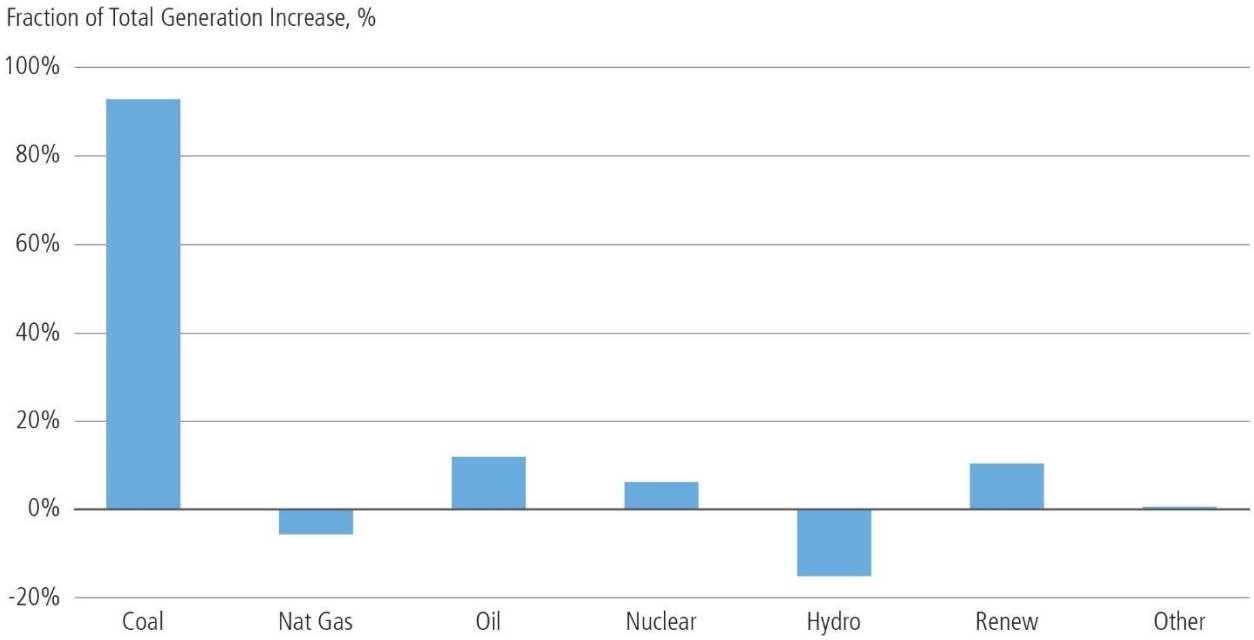
Figure 4.19. Coal Stocks and Days of Burn, January 2010–May 2017[332]



While bituminous coal stockpiles in tons have been slightly lower than historic averages in recent months, these stocks are expected to last relatively longer than historic average (measured in days of burn) due to lower capacity factors and expected lower fuel consumption in coal plants. Subbituminous coal stocks (not pictured) have increased in recent months relative to historic averages both in terms of tons and days of burn.

For the winter of 2014, compared to 2013, coal-fueled generation provided 92 percent of increased generation, as shown in Figure 4.20. Although electricity demand was greater in 2014, natural gas generation decreased because natural gas was diverted to fuel residential heating needs and gas prices rose to greater than three times those of coal.

Figure 4.20. Electricity Generation Changes from 2013 to 2014 by Fuel Type



Competition for natural gas between residential heating and power production caused a rise in natural gas prices in the early months of 2014. The high gas prices coupled with onsite coal storage led to a sharp increase in coal electricity production in those months compared to the winter of 2013.

Coal plants can also experience delivery interruptions. In 2013, there were 166 power plants (172,000 MW of generating capacity) across the United States that used subbituminous coal from the Powder River Basin. During the winter of 2013–2014, BNSF Railway rationed and limited coal deliveries to many of these generators due to construction and other disruptions. Stockpiles fell from 25 percent to 40 percent below normal levels at coal plants across the Midwest, Central, and Texas regions; many plants feared that they might not be able to rebuild their inventories in time to meet winter electric demands.[333]

4.3 High-Risk Events and System Resilience

The April 14 memo asks whether wholesale energy and capacity markets are adequately compensating attributes that strengthen grid resilience and, if not, the extent to which not compensating resilience attributes could affect grid reliability and resilience in the future.

A resilience approach recognizes that while not all risks can be avoided, many risks can be managed to mitigate damage and expedite recovery. Some options to improve grid resilience may be risk-specific (e.g., to protect against flooding) or component-specific (to protect a transformer), while others are "threat-agnostic, providing system-wide resilience to a broad range of threats including those that cannot be anticipated" according to the Grid Modernization Lab Consortium (GMLC).[334] As the fuel mix evolves and as threats change, there will be more ways that elements and regions of the BPS can fail. Causes of failure can include extreme weather events and cyber or physical attacks on grid infrastructure. [335] [336]

Extreme Weather Events

In January and February 2014, the Nation was swept by the Polar Vortex as a band of very cold weather spread across much of the eastern United States, creating record-high winter peak electric demand for heating and equally high demand for natural gas for residential heating. While the Polar Vortex tested the integrity of electricity supply, grid operators generally met demand, even under these severe conditions.

However, electricity and gas prices surged for many consumers as energy supplies were stressed. The extremely cold weather caused a variety of power system performance problems, including the loss of 35,000 MW of generation capacity across a wide stretch of the Nation, with 55 percent of the affected generation from natural gas plants, 26 percent coal plants and five percent nuclear.[337] In PJM, one of the regions most affected by the event, 22 percent of generating capacity was in forced outage.[338]

Many natural gas-fired generators had their fuel supplies curtailed because they were buying gas on non-firm, interruptible contracts, or because demand was so high that pipelines implemented delivery restrictions to power plants located near major metropolitan areas. In the Northeast, after several days of extremely cold weather, some generators experienced fuel-gelling, where the natural gas froze in the fuel injectors and was unable to feed into the turbines.[339] In Texas, a major source for natural gas production and a transport hub, several gas field production facilities froze up, as did some gas compressor stations along pipelines—shutting down gas feeds into and through pipelines that were to be shipped into New Mexico and elsewhere. This caused fuel shortages to the power plants served by those pipelines.[340] Limited supplies led to natural gas price spikes across much of the country; in some areas, gas to produce electricity was more expensive than liquid fuel, even though the price of oil for generation rose to over $400 per barrel. [341]

Many coal plants could not operate due to conveyor belts and coal piles freezing[342], which—coupled with outages across other fuels and high electricity demand—led operators to call on older plants nearing the end of their useful lives. American Electric Power reported that it deployed 89 percent of its coal units scheduled for retirement in 2014 to meet demand during the Polar Vortex, and Southern Company reported using 75 percent of its coal units scheduled for closure.[343] Using these retiring units enabled utilities to meet customer demand during a period when already limited natural gas resources were diverted from electricity production to meet residential heating needs.[344] [345] Once retired, however, these units will not be available for the next unseasonably cold winter.

In October 2012, Superstorm Sandy caused large-scale flooding and wind damage in the Mid-Atlantic and Northeast, as well as blizzard conditions in the central and southern Appalachians. Three nuclear reactors totaling 2,845 MW of capacity were shut down, and five operated at reduced levels due to disruptions in transmission infrastructure, reduced demand from distribution outages, and precautionary measures to protect equipment.[346] The storm impacts significantly disrupted East Coast refining activity. Spectra Energy lost two natural gas compressor stations on its Texas Eastern Transmission pipeline in northern New Jersey due to the loss of commercial power and the failure of backup generation to operate as intended, which affected gas supply to upstream gas-fired power plants. New Jersey Natural Gas shut down part of its natural gas infrastructure serving Ocean and Monmouth counties, including Long Beach Island and the barrier islands from Bay Head to Seaside Park, with subsequent distribution line damages.[347] Sandy also damaged solar PV installations in New Jersey, with storm surges causing $3 million of damage to ground-mounted PV systems and wind and lightning damage to rooftop PV systems.[348]

4.4 Enhancing Reliability and Resilience

Recently, based on extensive information about the operational profiles of PJM resources, PJM assessed the capability of each generator type to provide different ERS.[mmm] PJM then built a series of hypothetical resource portfolios using different mixes of generation types to determine how well each portfolio performed at delivering sufficient reliability. PJM also considered the risk that each portfolio would fail to meet resource adequacy needs and thus cause reliability problems. After simulating many combinations and portfolios, the following conclusions were reached:

- The expected near-term resource portfolio is among the highest-performing portfolios and is well equipped to provide the generator reliability attributes.
- As the potential future resource mix moves in the direction of less coal and nuclear generation, generator reliability attributes of frequency response, reactive capability and fuel assurance decrease, but flexibility and ramping attributes increase.
- A marked decrease in operational reliability was observed for portfolios with significantly increased amounts of wind and solar capacity (compared to the expected near-term resource portfolio), suggesting de facto performance-based upper bounds on the percent of system capacity from these resource types. Additionally, most portfolios with solar unforced capacity shares of 20 percent or greater were classified infeasible because they resulted in LOLE criterion violations at night. Nevertheless, PJM could maintain reliability with unprecedented levels of wind and solar resources, assuming a portfolio of other resources that provides a sufficient amount of reliability services.
- Portfolios composed of up to 86 percent natural gas-fired resources maintained operational reliability. Thus, this analysis did not identify an upper bound for natural gas. However, additional risks, such as gas deliverability during polar vortex-type conditions and uncertainties associated with economics and public policy, were not fully captured in this analysis. Risks with respect to natural gas may lie not in capability to provide the generator reliability attributes but rather in these other uncertainties.
- More diverse portfolios are not necessarily more reliable; rather, there are resource blends between the most diverse and least diverse portfolios which provide the most generator reliability attributes.[349] [original footnotes omitted]

Significantly, when PJM tested the most desirable portfolios (in terms of reliability) against a polar vortex event, only a third of those were resilient:

> Only 34 of the 98 portfolios which were classified as desirable were resilient when subjected to a polar vortex event. This sensitivity specifically captured the increased risk of natural gas delivery under extremely cold and high load conditions. The polar vortex sensitivity highlights the importance of resilience, which is not captured by the generator reliability attributes that were considered in this study.[350]

DOE, NERC, and industry stakeholders prepare for a variety of potential threats, including high-impact, low-frequency events, to improve resilience and recovery. Planning, practice, and coordination on an all-hazards basis are as important for improving resilience as having a mix of resources and fuels available when a major grid disturbance occurs. A diverse resource portfolio could complement wholesale market products that recognize and compensate providers for the value of ERS on a technology-neutral basis.

[mmm] The PJM study assumed firm gas supply contracts for natural gas-fired generators.

DOE's Grid Modernization Initiative (GMI) works to better understand what resilience means for the power system and how to measure and achieve it.

Transmission planning also supports grid reliability and resilience through interconnecting diverse resources, and it occurs at a variety of levels—ranging from individual utility system studies to regional and interconnection-wide studies. In 2009, DOE issued a series of grants to support interconnection-wide transmission planning. In 2011, FERC issued Order No. 1000, which (among other requirements) mandates regional transmission planning and interregional coordination. As noted in a recent study for the WIRES group:

> The analytical approaches applied to interregional [transmission] planning should look beyond "base cases" or "business-as-usual cases" and explicitly consider a broader range of plausible market conditions, system contingencies, and public policy environments to capture the short- and long-term flexibility benefits and insurance value that a more robust interregional transmission infrastructure can offer in terms of shielding customers from high-cost outcomes.
>
> … we recommend that such futures be evaluated to identify transmission projects that address current needs but also provide the insurance and flexibility value to mitigate high-cost outcomes across a range of uncertain but not implausible futures.[351]

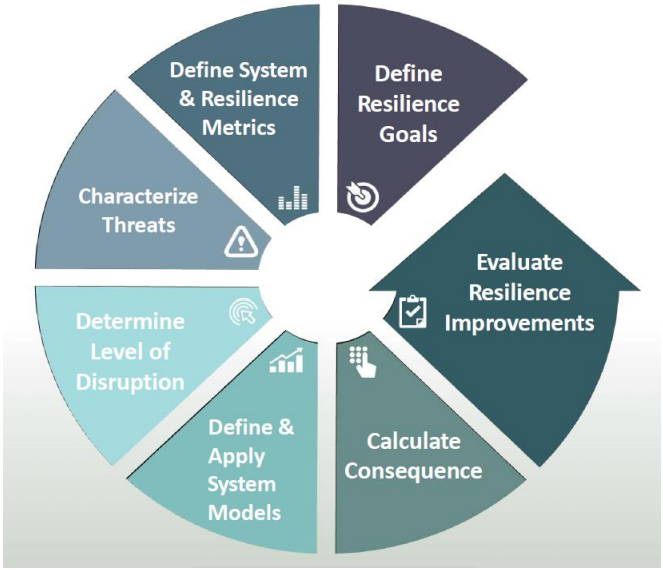
Given the many problems that can affect different generation and fuel types, system-wide reliability and resilience can be supported by a diverse portfolio of generation resources that limit over-dependence on any single fuel or technology type, plus demand-side resources that reduce overall demand and better protect customers in the event of a widespread extreme event.

4.5 Reliability and Resilience Looking Forward

Although the BPS is performing reliably today with the current mix of resources, technologies, and loads, the entire system remains volatile. Low customer demands and a flatter supply curve mean that many generators face continuing economic stress, retirements may continue, and utility-scale and customer-side VRE additions (enabled by subsidies and mandates) will continue. These factors and the uncertainty about future conditions are making it harder for grid planners and operators to maintain today's level of reliability.

Any successful strategy to address BPS reliability and resilience going forward should include developing portfolios of resources that deliver both resource adequacy and ERS to advance reliable grid operations. Resource portfolios could be complemented with wholesale market and product designs that recognize and complement resource diversity by compensating providers for the value of ERS on a technology-neutral basis. More work is needed to define, quantify, and value resilience; Sandia National Laboratories has made efforts to do so, as shown in Figure 4.21.

Figure 4.21. Sandia National Laboratories' Resilience Analysis Process[352]



5 Wholesale Electricity Markets

The wholesale electricity market issues outlined in the April 14 memo are central to the future of U.S. electricity markets and policy. At the same time, they are the subject of intense debate among stakeholders with differing regional and economic interests. Noting the wide range of opinion on these issues, DOE staff offer three general findings:

1) Changing circumstances are challenging centrally-organized wholesale markets. Flat demand growth, Federal and state policy interventions, and the massive economic shift in the relative economics of natural gas compared to other fuels are creating stresses on wholesale electricity markets. The centrally-organized markets are successfully achieving reliable and economically efficient delivery of wholesale electricity in their short-term operations, but the changing circumstances portend potential long-term problems for centrally-organized and, to a lesser extent, bilateral markets.

2) New technologies with very low marginal costs, i.e. VRE, reduce wholesale prices, independent of—and in addition to—the effects of low natural gas prices. To the extent that additional development of such resources is driven by subsidies and mandates, their price suppressive effect might place undue economic pressure on revenues for traditional baseload (as well as non-baseload) resources and could require changes in market design.[353] [354] [355]

3) Markets need further work to address grid resilience. Market mechanisms are designed to incentivize individual resources rather than develop balanced portfolios. System operators are working toward recognizing, defining, and compensating for reliability- and resilience-enhancing resource attributes (on both the supply and demand side), but more work must be done.

U.S. market structures vary widely, but despite substantial differences between markets, some patterns emerge and are worth addressing in response to the April 14 memo.

5.1 Evolution of U.S. Wholesale Electricity Markets

Until the 1970s, investor-owned electric utilities were vertically integrated (i.e., provided generation, transmission, and distribution of electricity to their customers at regulated rates and with administratively determined profits). This concept was loosely referred to as the “regulatory

compact."[nnn] Interspersed with VIEUs were—and still are—over 3,200 cooperatively owned electric utilities.[ooo] [356]

In the 1920s, policymakers accepted the idea that non-utility companies might be able to generate electricity at equal or lower cost than VIEUs, to the benefit of electricity consumers.[357] In 1978, Congress passed the Public Utility Regulatory Policies Act (PURPA), which introduced competition to the VIEU model and set the stage for later regulatory reform of the electricity industry.[358] At the time, PURPA was largely an effort to curb the electricity industry's reliance on high-cost natural gas and oil.[ppp] PURPA provided for "increased conservation of electric energy, increased efficiency in the use of facilities and resources by electric utilities, and equitable retail rates for electric consumers." [359] It also made developing new generation resources easier—specifically renewable energy and cogeneration facilities.[360]

The Energy Policy Act of 1992 allowed FERC to approve "exempt wholesale generators," using any fuel and any generation technology, to go into the generation business and sell electricity at competitive prices. The act also authorized FERC to order transmission owners to provide transmission service.[361] Also in 1992, Congress enacted the PTC to incentivize VRE energy production, which Congress has extended and modified several times since.[362]

In 1996, FERC required transmission owners under its jurisdiction to provide open-access transmission to the interstate transmission grid through its landmark Order No. 888. Open access means charging all similarly situated parties the same rate (including, if applicable, what the utility would charge itself to use its transmission facilities) and providing service to all similarly situated parties under the same terms and conditions.[363] This action by FERC greatly assisted the development of competition among wholesale power producers because it meant that utilities would find it difficult to limit access to their transmission facilities as a means of protecting their generation assets from competitors. FERC Order No. 2000 (issued in December 1999) promoted voluntary participation in RTO/ISOs by further clarifying both necessary characteristics of RTO/ISOs and benefits of such participation.[364]

Between 1998 and 2006, 23 states made changes to require their VIEUs to divest some or all of their generating assets and thus allow competition.[365] Divestiture was pursued most aggressively by the states with high retail electricity prices (most of New England, New York, the Mid-Atlantic states, and

---

[nnn] "The 'state regulatory compact' evolved as a concept 'to characterize the set of mutual rights, obligations, and benefits that exist between the utility and society.' It is not a binding agreement. Under this 'compact,' a utility typically is given exclusive access to a designated—or franchised—service territory and can recover its prudent costs (as determined by the regulator) plus a reasonable rate of return on its investments. In return, the utility must fulfill its service obligation of providing universal access service within its territory. https://www.energy.gov/sites/prod/files/2017/02/f34/Appendix--Electricity%20System%20Overview.pdf

[ooo] Most public power utilities are distribution-only; however, some are vertically integrated. Distribution-only cooperatives typically purchase all or some of their electricity at the wholesale level from generation and transmission cooperative utilities.

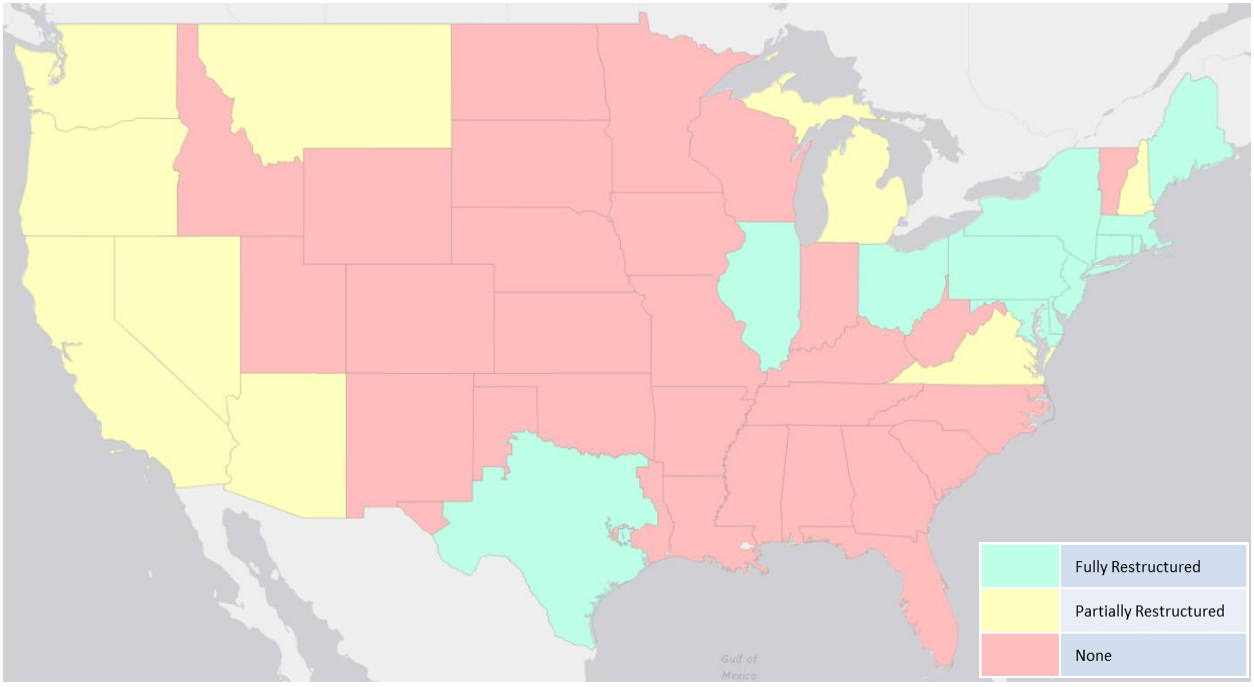
[ppp] Also in 1978, the Power Plant and Industrial Fuel Use Act prohibited "(1) the use of natural gas or petroleum as a[n] energy source in any new electric power plant; and (2) construction of any new electric power plant without the capability to use coal or any alternate fuel as a primary energy source." https://www.congress.gov/bill/95th-congress/house-bill/5146

The Fuel Use Act was mostly repealed in 1987, which "set the stage for a dramatic increase in the use of natural gas for electric generation and industrial processing." https://www.eia.gov/oil_gas/natural_gas/analysis_publications/ngmajorleg/repeal.html

California) with the hope that competition would bring lower retail consumer prices.[qqq] [366] Generating units that had been operating under cost-of-service regulation were sold to merchant plant owners or transferred to unregulated, investor-owned utility affiliates.

This wave of restructuring did not sweep the entire Nation. In large areas—particularly the Southeast and the West, apart from the expanding Energy Imbalance Market—the wholesale electricity industry is still vertically integrated. In these areas, the wholesale market consists of bilateral transactions. Because restructuring did not take hold in all states, a range of organizational structures exist at the wholesale level in the United States today, as shown in Figure 5.1. States considered "Partially Restructured" below have divested some generation and/or allowed a portion of customers to choose their energy provider.

Figure 5.1. Utility Restructuring by State as of May 2017[367]



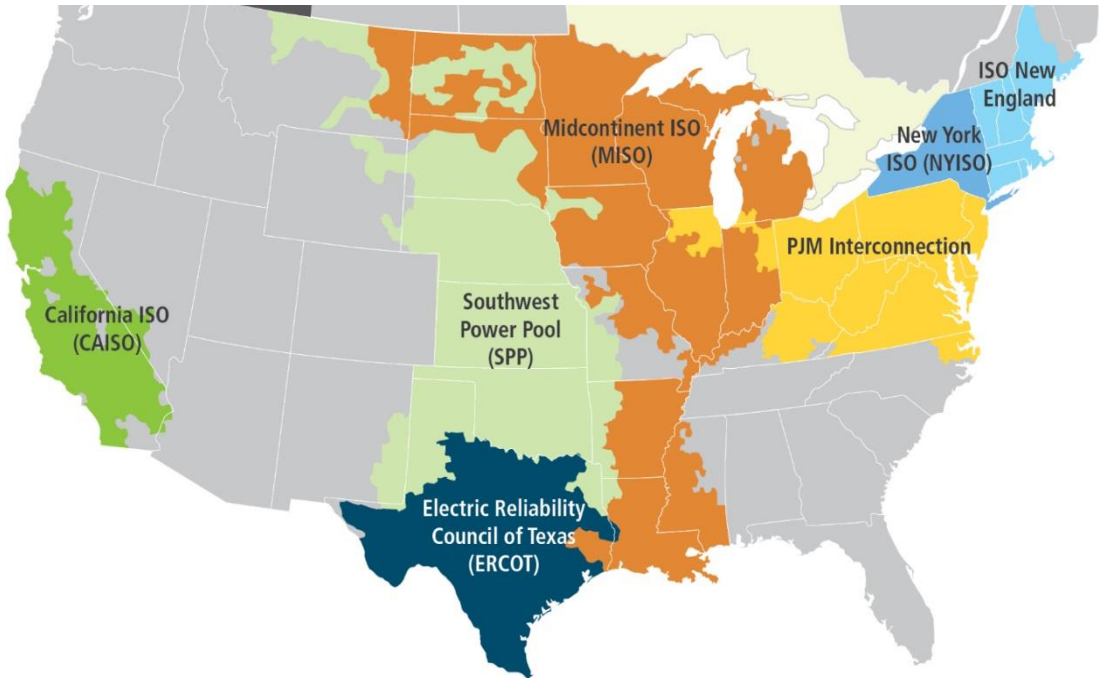
5.2 Wholesale Electricity Markets Today

Over the past two decades, a diverse set of wholesale electricity markets has evolved in different regions of the United States. These wholesale markets can be divided into two broad categories. For the purposes of this section, regions of the country that have not joined RTO/ISOs are called traditional

[qqq] Whether this objective has been achieved is mixed in the literature. Availability rates for generation have improved significantly and, as predicted, as competition incentivized operators to run their units as efficiently as possible. Dispatch over the much broader footprints of RTO/ISOs also increases efficiency and thus reduces costs. PJM notes (July 26, 2017 written statement before Subcommittee on Energy, U.S. House Committee on Energy and Commerce) "nearly $2 billion of annual savings to customers." On the other hand, Borenstein's 2015 review claims "the electricity rate changes since restructuring have been driven more by exogenous factors - such as generation technology advances and natural gas price fluctuations - than by the effects of restructuring." See two meta-studies: Severin Borenstein and James Bushnell, "The U.S. Electricity Industry after 20 Years of Restructuring," May 2015, https://ei.haas.berkeley.edu/research/papers/WP252.pdf and James Bushnell, Erin T. Mansur, and Kevin Novan, "Review of the Economics Literature on US Electricity Restructuring," April 2017, for DOE, unpublished.

bilateral markets, while those that have are called centrally-organized markets. These regions are shown in Figure 5.2, with RTO/ISOs labeled and colored, and bilateral markets depicted in gray.

Figure 5.2. The Seven RTOs or ISOs in the United States[rrr] [368]

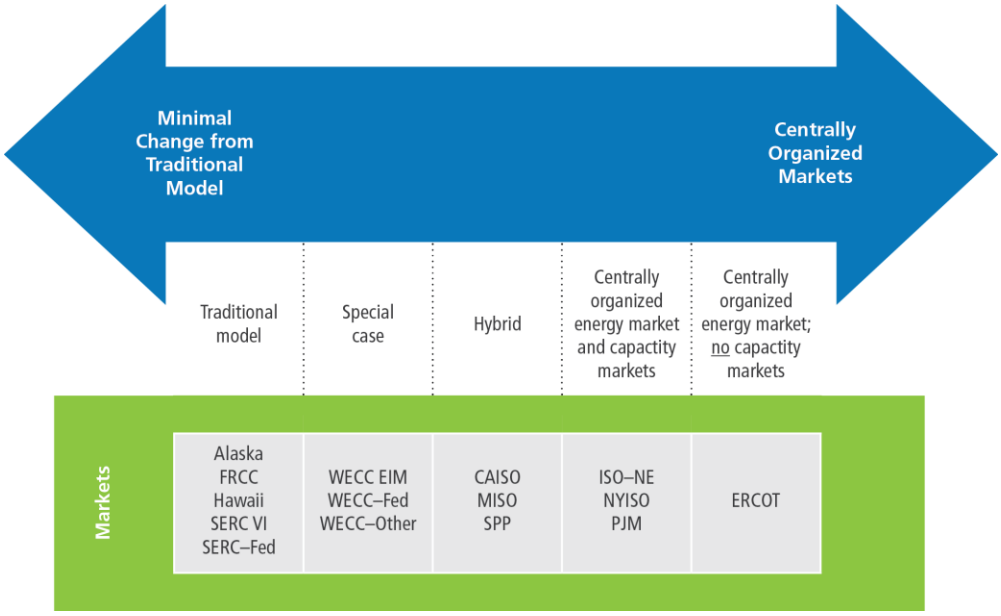


There are currently seven centrally-organized markets operating across the United States.

The diversity of approaches to market organization and resource adequacy can be visualized along a spectrum, as shown in Figure 5.3—from VIEUs with minimal market organization on one end, to fully restructured markets without formal resource adequacy requirements on the other. Between vertically integrated and energy-only regions, there are diverse approaches to allocating the financial risk of generation investment and the responsibility to provide resource adequacy.

[rrr] Map redrawn from FERC's December 2016 website.

Figure 5.3. States and Regions along the Spectrum from Traditional to Fully Restructured Electric Markets[369]



In the Southeast and West, bilateral markets are dominated by VIEUs that operate under a regulated cost-of-service model. States in these regions retain strong control over electric utility resource decisions and oversee resource adequacy, and they consider non-market factors in their oversight of utility decisions through a utility's IRP process. Once approved by state regulators, ratepayers guarantee the cost recovery of VIEU generation investments through retail rates (or merchant generators through long-term PPAs with utilities). Thus, the financial viability of these generators is not immediately exposed to the same price volatility that generators face in market-oriented regions. However, new resource decisions in VIEU regions are beginning to account for low natural gas prices, low load growth, and zero-marginal cost generation.[sss]

Public power and rural cooperative utilities also have a significant presence in some regions. Utility asset ownership models can vary from vertically integrated to distribution-only. Merchant generators also operate within these regions, but most electricity is produced and delivered by the integrated utilities, with minimal additional spot transactions.[370]

In centrally-organized markets, generators offer electricity bids on a day-ahead and real-time basis. The RTO/ISO then pools these bids into a single supply curve and calculates the clearing price that matches supply to demand, considering transmission limitations for the next interval. This calculation yields a set of market-clearing prices, one for each location and time horizon. Centrally-organized markets also compensate resources that provide certain ERS through ancillary service markets. Furthermore, in some cases, RTO/ISOs provide supplemental revenues to generators that are dispatched out-of-market, such as ones that are needed to ensure local reliability.

[sss] See, for example, 152 FERC ¶ 61,013 (Florida Power & Light Company) or Steve Wright, General Manager, Chelan County PUD, a vertically integrated utility in Washington, told DOE staff in a June 19, 2017, conversation that the relatively low wholesale prices traditionally seen in the Northwest due to an abundance of low-cost hydro are now further stressed by the export of surplus zero-marginal cost California rooftop solar, so much so that he is "finding it hard to even justify spending on energy efficiency in [his utility's] integrated resource plan."

RTOs/ISOs operate as a single balancing authority and achieve cost savings by procuring reserves and other ancillary services for the system. For example, MISO estimates that because it operates an ancillary service market across the entire region, spinning reserve requirements can be based upon the entire region's needs rather than the sum of individual balancing authorities' spinning reserve requirements. By operating the ancillary services market, MISO reduced its average spinning reserves requirement from 1,482 MW to 935 MW and saved almost $25 million per year for its members by freeing up generation from having to meet the reserve requirement.[371]

CAISO, MISO, and SPP retain aspects of the bilateral markets, particularly that states still oversee resource procurement and resource adequacy of their VIEUs, through the IRP process.[372] California, MISO and SPP, as well as traditional bilateral market states, incorporate considerations other than short-term economic efficiency into their resource choices, such as portfolio diversity, job retention or creation, environmental protection, and other factors.

5.2.1 Responsibility for Resource Adequacy and Capacity

Some states require utilities to build new or subsidize specific power plants outside the RTO/ISO resource adequacy processes. Other centrally-organized markets (namely PJM, ISO-NE, and NYISO) have implemented capacity markets as a mechanism to provide sufficient revenue for resources to ensure resource adequacy. In these markets, the system operator conducts an auction process, and wholesale customers procure resources (including generation, energy efficiency, DR, and transmission-enabled resource imports) to meet the electricity demands of their customers. These markets can be mandatory (PJM Interconnection and ISO New England); voluntary, where states can choose to operate under an IRP process and where load-serving entities can satisfy their requirements through a combination of the market and/or showing that they have rights to adequate capacity (MISO); or voluntarily backstopped by a mandatory process (NYISO). ERCOT does not have a formal resource adequacy requirement.

5.3 Challenges in Wholesale Electricity Markets

Centrally-organized markets are now 15–20 years old, and their original designs (even with continual and evolving updates) are showing signs of strain from the pace of change now underway in the electricity industry. Many of these changes were not foreseen during the restructuring and wholesale market designs of the 1990s–2000s. Flat demand growth, flattened supply curves, Federal and state policy interventions, and the massive economic shift in the relative economics of natural gas compared to other fuels are placing pressures on centrally-organized wholesale electricity markets, resulting in low average wholesale energy prices. These markets were designed when supply curves tilted sharply upward, demand grew over time, and capacity was not explicitly compensated to make up for insufficient revenues from an energy-only market. A 2014 FERC staff report notes:

> A failure to properly reflect in market prices the value of reliability to consumers and operator actions taken to ensure reliability can lead to inefficient prices in the energy and ancillary services markets leading to inefficient system utilization, and muted investment signals.[373]

The issue of revenue insufficiency and generator retirements in centrally-organized electricity markets is a complex topic, with causality difficult to assign beyond the individual asset/owner level.[ttt] Each plant has its own cost structure, and plant revenues can differ between neighboring nodes in a single market.

Traditional, bilateral-only wholesale markets are not immune to these issues either, but may not be seeing them yet at the same scale as the three eastern RTO/ISOs that have a predominance of merchant generation. An issue that is more prevalent in these regions than in regions with bilateral markets is the PURPA "must-purchase obligation" that still applies to those regions. After Congress amended PURPA in the Energy Policy Act of 2005, many utilities in regions with centrally-organized wholesale markets have sought and received from FERC orders terminating their obligations.[374]

By contrast, utilities in regions with traditional, bilateral-only wholesale markets remain subject to the PURPA requirement to buy power from Qualifying Facilities (QFs) under PPAs, with up to 20-year terms and at rates that the applicable state regulator has determined reflect the purchasing utility's avoided costs. In some instances, generation purchased from QFs has displaced utility-owned generation and thus reduced utility revenue. PURPA remains a subject of ongoing debate within the industry, as evidenced by a discussion during a FERC June 2016 Technical Conference.[375]

5.3.1 Revenue Insufficiency due to Market Structure: The Missing Money Problem

In the mid-2000s it became apparent that merchant generators were failing to recover sufficient revenues through the energy-only markets to cover both their variable and fixed costs. The issue subsequently became known as the "missing money problem."[uuu] In testimony before a 2014 FERC technical conference, David Patton, the independent market monitor for ERCOT, ISO-NE, MISO, and NYISO, described the issue as stemming from overly-stringent planning reserve requirements:

> With reasonable assumptions about capacity cost and energy prices, [the one-day-in-ten-years] reliability standard implies a value of lost load of $100,000 to $200,000 per MWh.
>
> Hence, without substantially inflated shortage prices, energy-only markets cannot provide enough revenue to satisfy planning reserve requirements. Additional revenue is needed to satisfy these requirements, which is the "missing money" problem addressed by the capacity markets.[376]

William Hogan of Harvard University noted in 2005 that the missing money problem can also be attributed to price caps:

> The missing money problem arises when occasional market price increases are limited by administrative actions such as price caps. By preventing prices from reaching high levels during times of relative scarcity, these administrative actions reduce the payments that could be applied towards the fixed operating costs of existing generation plants and the investment costs of new plants.[377]

To mitigate the missing money problem, centrally-organized markets have, to varying degrees, utilized shortage pricing and capacity markets.

[ttt] The market issues discussed in this section are most pertinent to a merchant generator operating within centrally-organized markets that are not subject to regulated rate recovery.

[uuu] The first use of this term is attributed to Roy Shanker in his 2003 testimony before FERC. William W. Hogan, Harvard University, "'Energy Only' Electricity Market Design for Resource Adequacy," September 23, 2005

Shortage Pricing

Shortage pricing, also referred to as scarcity pricing, seeks to ensure that energy market revenues reflect the value consumers place on reliability. It does this through administrative rules that raise prices above marginal costs during times of system stress. FERC has actively sought to improve the utilization of techniques like shortage pricing. In a 2014 analysis, FERC staff provided a useful overview of the rationale for shortage pricing:

> When the system operator is unable to meet system needs, it applies administrative pricing rules to ensure that costs, including the costs associated with the failure to meet minimum operating reserve requirements, are reflected in market prices. …Under such conditions, prices should rise, inducing performance of existing supply resources and encouraging load to reduce consumption so that the system operator would not need to administratively curtail load to maintain reliability. [378]

All of the Nation's RTO/ISOs currently employ shortage pricing to some degree; however, the designs are not uniform. FERC Order No. 831 raised energy offer caps in jurisdictional RTO/ISOs from $1,000 to $2,000/MWh.[379] Conditions required to trigger shortage pricing vary from year to year. This variance could present challenges to market participants who require a threshold level of certainty to make an investment decision. Remarks by market monitors David Patton and Joe Bowring critique the practice of relying solely on shortage pricing:

> [David Patton:] Shortage pricing is not like a capacity market where you're going to get a level of revenue that might fluctuate by 10 to 20 percent per year. With shortage pricing, you might get 10 years of revenue in one year and then the other nine years the generators are going to think they're going bankrupt.[380]
>
> [Joe Bowring]: What will happen if you go through eight years of very low revenues under scarcity pricing … and a significant number of units decide to retire because they can't see into the future? They don't know if [in] the ninth or 10th year there's going to be $20 billion. They retire if the revenues aren't adequate.[381]

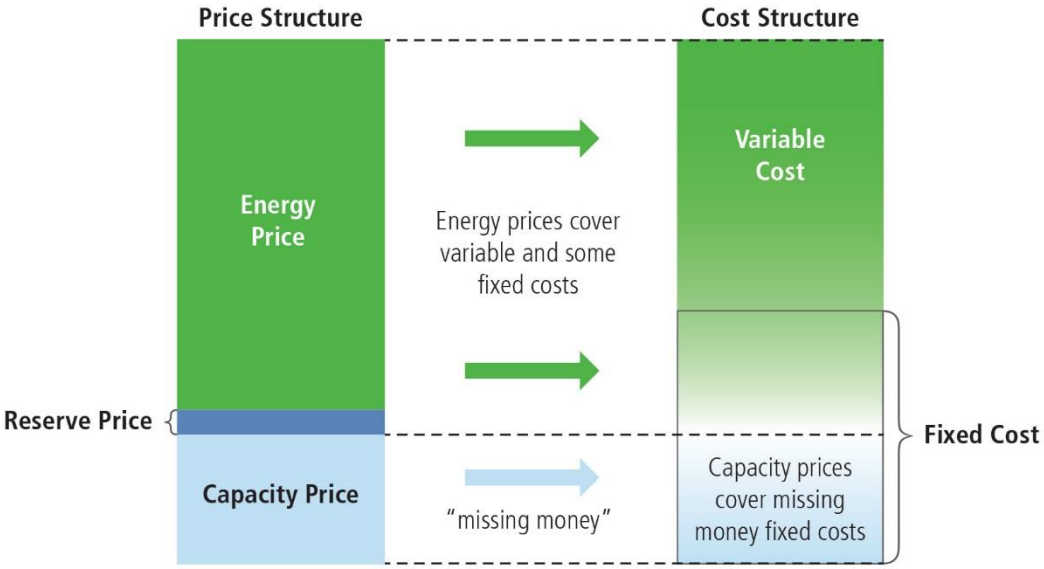
Capacity Markets

Four RTO/ISOs currently operate centralized capacity markets: ISO-NE, NYISO, and PJM hold mandatory auctions, while MISO's is voluntary. Capacity markets address the missing money problem by imposing resource adequacy requirements on load-serving entities (LSEs). Spees, Newell, and Pfeifenberger provide a useful overview of how this process works:

> A resource adequacy [requirement] requires LSEs to procure sufficient generation or demand-response capacity to serve their own customers' coincident peak load plus a mandatory planning reserve margin. If each LSE procures their required capacity, then the system as a whole will be able to meet its planning reserve margin requirement and target resource adequacy level. … [Capacity] has value as a stand-alone commodity, the demand for which is driven by LSEs needing to meet their resource adequacy requirement.[382]

According to the authors, capacity market revenues should in theory ameliorate the missing money problem by providing "the incremental payment needed to recover their investment costs in addition to the operating profits earned through energy and ancillary service sales."[383] Figure 5.4 provides a useful illustration of how capacity payments are intended to close the missing money gap.

Figure 5.4. How Market Prices Allow Resource Costs to be Recovered in a Centrally-organized Wholesale Market[384]



Revenues from energy sold in the wholesale market pay for a generators' variable costs and some portion of fixed costs (indicated by green arrows). The unrecovered portion of fixed cost (missing money) is recovered through capacity market revenues (indicated by blue arrow).

Some observers note that capacity markets may not provide sufficient revenues as originally intended. For example, the 2016 PJM Market Monitor's report finds PJM's markets can provide adequate revenue to support *some* existing capacity, but the outlook varies widely by technology, fuel choice, time interval, and location:

> Analysis of the total unit revenues of theoretical new entrant CTs and CCs for three representative locations shows that units that entered the PJM markets in 2007 have not covered their total costs, including the return on and of capital, on a cumulative basis through 2016. The analysis also shows that theoretical new entrant CTs and CCs that entered the PJM markets in 2012 have covered their total costs on a cumulative basis in the eastern PSEG [New Jersey] and BGE [Baltimore] zones but have not covered total costs in the western ComEd [Chicago] Zone. Energy market revenues were not sufficient to cover total costs in any scenario except the new entrant CC unit that went into operation in 2012 in BGE, which demonstrates the critical role of capacity market revenue in covering total costs.[vvv 385]

5.3.2 Revenue Insufficiency due to External Forces

While RTO/ISOs have sought to address the missing money problem as previously defined, newer variants of it continue to permeate stakeholder discussions. Economist Severin Borenstein notes that the definition has expanded to include the supply curve impact of subsidies:

> Money has been going missing for many years, according to owners of power plants. They've used the term for more than a decade to refer to the fact that wholesale electricity markets have price caps (mostly between $1,000 and $10,000 per MWh) that constrain how

[vvv] As part of the review of market performance, the market monitor analyzed the net revenues earned by CTs, NGCCs, coal, diesel, nuclear, solar, and wind generating units.

> much sellers can make when supply is tight. Without that income, generators argue, it may not be profitable to build new capacity, or extend the life of existing capacity, that is needed to meet demand.
>
> More recently, the definition of missing money has been expanded to include the price impacts of subsidized or mandated renewables generation. In California, New York and many other states, wind and solar are pushing down wholesale prices and making continued operation of some nuclear and fossil fuel generation unprofitable. [386]

Shifts in the Generation Supply Curve

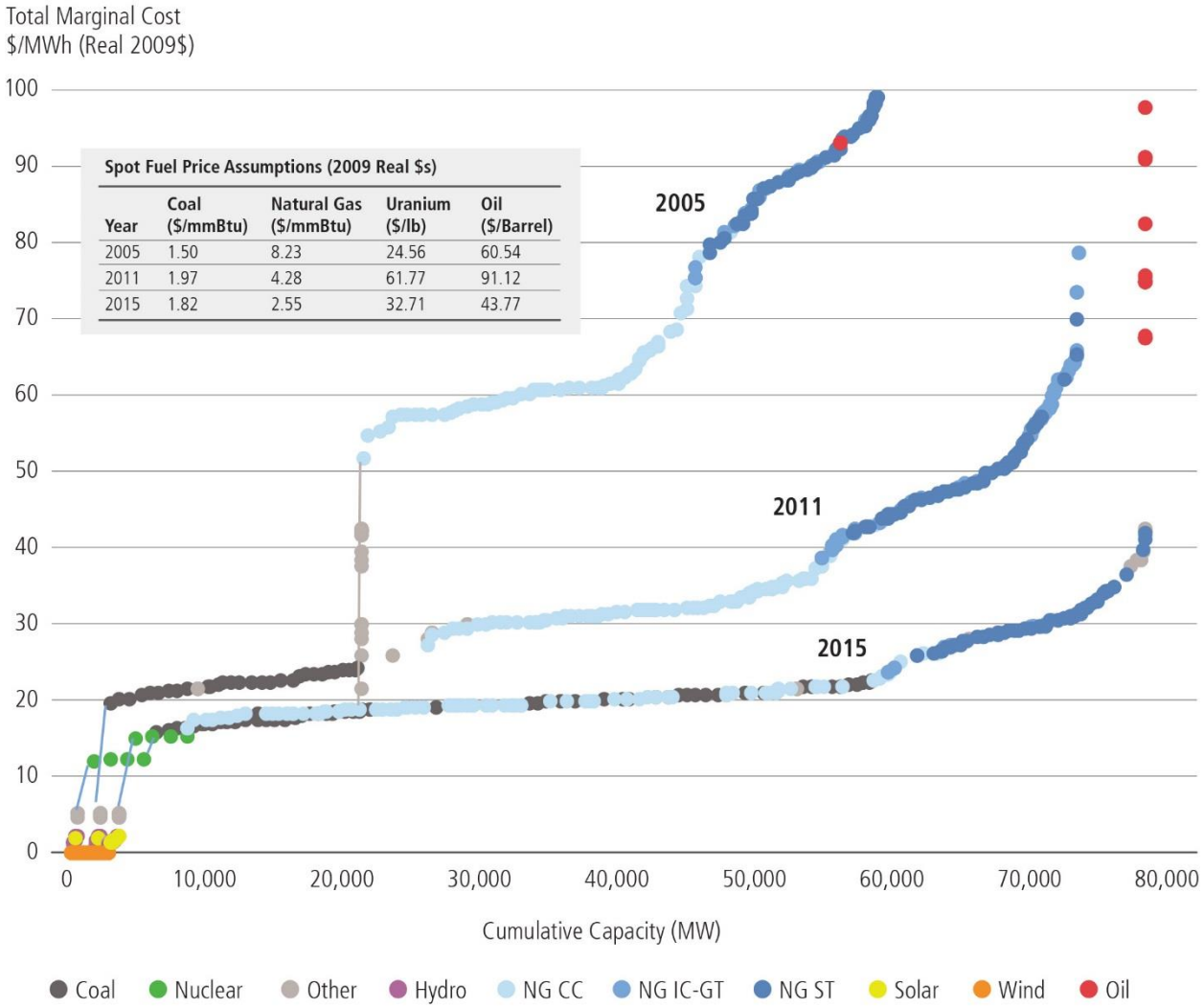
Changes in the Nation's generation mix have generally reduced revenues for incumbent baseload generators in wholesale markets, as highlighted in QER 1.2:

> [P]rice suppression is occurring in RTO/ISO wholesale markets, with noticeable amounts of wind and solar generation (and low-cost gas generation). While passing on savings to consumers is desirable, in some regions, these low prices have put pressure on baseload units, particularly zero-carbon emissions nuclear generation.[387]

Put more specifically, shifts in market supply curves have lowered the infra-marginal rents[www] earned by baseload generators. Crucially, this reduction has occurred because of changes along *both* axes of the supply curve. Along the horizontal (supply) axis, the entry of new resources has pushed the curve to the right, resulting in a lower clearing price at the same level of demand. Meanwhile, reductions in marginal fuel costs (vertical axis) have lowered the slope of the curve. The net effect of these changes—as illustrated by a simulated dispatch curve in ERCOT—is shown in Figure 5.5.

[www] Infra-marginal rents are the differences between the market-clearing price and the submitted bid of each generator. Generators that bid less than the market-clearing price receive a payment equal to this difference.

Figure 5.5. Simulated ERCOT Dispatch Curves[xxx]



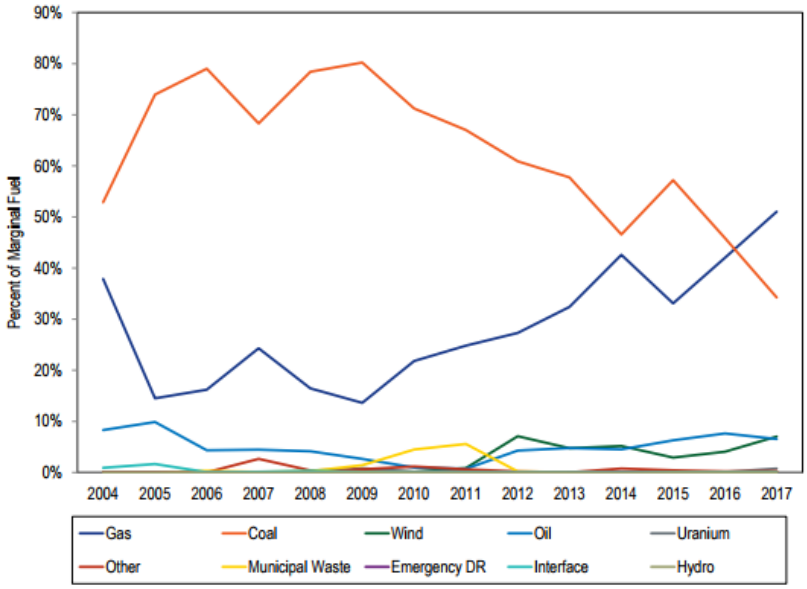
Changes in fuel costs and the supply mix have impacted market clearing prices, and thus lowered infra-marginal rents for incumbent generators. Reductions in natural gas prices have clearly flattened the curve, reducing revenues for generation resources. The entry of new, near-zero marginal cost resources has also pushed the overall curve to the right. The entry of wind and solar resources is visible in lower left.

Natural Gas and Incumbent Baseload

The frequency with which natural gas sets the price of electricity has increased in many of the Nation's markets. For example, 2017 could mark the first time in PJM's history that gas is marginal for more intervals than coal (see Figure 5.6). This transition means that infra-marginal rents that were previously based on the marginal cost of coal resources have been supplanted by the marginal cost of natural gas resources.

[xxx] EIA, analysis performed for DOE using EIA and ABB Ventyx software to show estimated plant-specific estimated production costs for July 15 of each year modeled, using then-current delivered energy prices (in 2009 $) within ERCOT and estimated, plant-specific heat rates to estimate plant-specific marginal costs of electricity production, June 2017

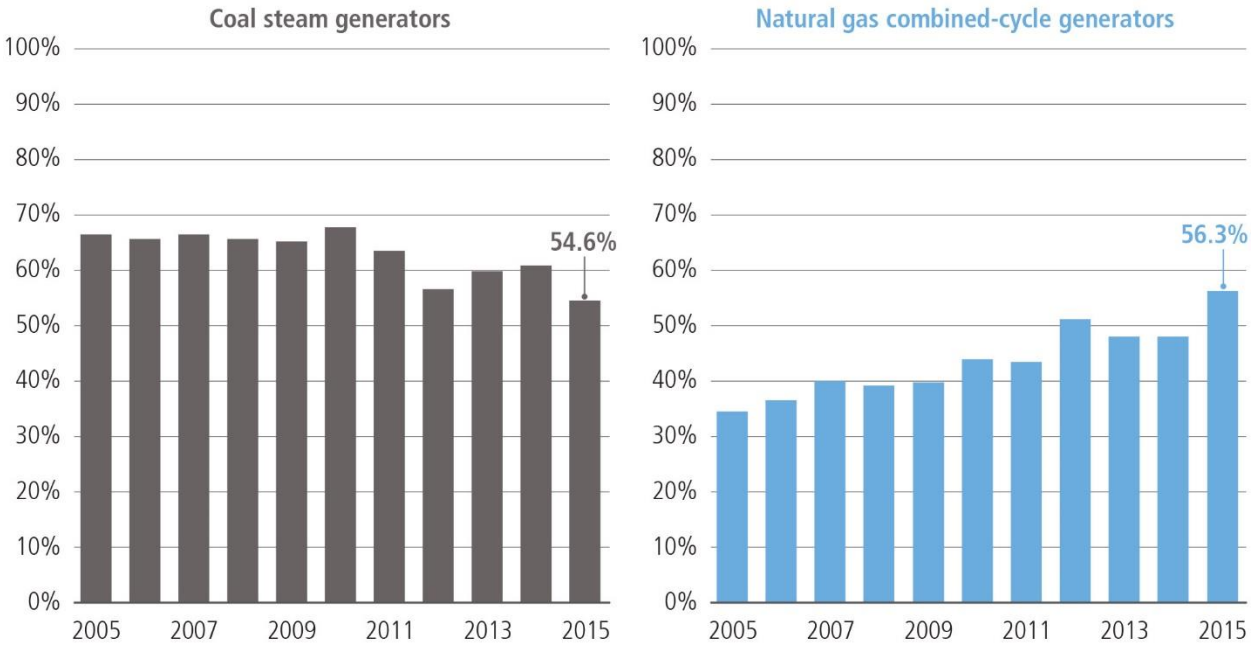
Figure 5.6. Type of Fuel Used in PJM (by Real-Time Marginal Units): 2004 through March 2017[388]



Natural gas is rising as the marginal electricity generation source in PJM.

The low price of natural gas has resulted in the competitive displacement of coal in many of the Nation's markets. This trend is visible in Figure 5.7 by comparing the 2005 curve to the 2015 version. The interspersed nature of the coal and gas generators in the 2015 curve reflects that the two now compete for the same runtime. While gas had been a mid-merit source in previous years, it has become more of a baseload resource in recent years. The phenomenon is visible on a national level by examining the capacity factors of the respective technologies.

Figure 5.7. Annual Average Capacity Factors of Coal and Natural Gas Generators



NGCC generators have seen a steady increase in fleet average capacity factor from 35% in 2005 to 56% in 2015; in that year, the NGCC fleet average eclipsed that of coal generators, which has declined from approximately 68% in 2010 to 55% in 2015.[389]

Negative Pricing

Negative pricing events in electricity markets reflect a complex set of economic, reliability, environmental, and safety variables. The interaction of these variables differs depending on the region, season, and time in question, but negative pricing often reflects some combination of excess generation (often exacerbated by must-run requirements), transmission constraints, and economic factors. According to analysis from LBNL, negative pricing events have historically been rare at many major pricing hubs (less than two percent of total hours in real-time markets in 2016), and have had almost no impact on annual average day-ahead or real-time wholesale electricity prices. However, more frequent negative pricing has been observed in CAISO, and in constrained hubs that feature a relatively large amount of VRE and/or nuclear generation.[390] In addition, PJM has observed that "prices go negative at nuclear units buses in approximately 2,176 hours – representing 14 percent of off-peak hours."[391]

The term economic factors in this case serves as a catchall for those negative pricing events that are not the direct result of must-run requirements. EIA provides examples of why generators might choose to run, even if it means accepting negative prices:

> Technical and economic factors may drive power plant operators to run generators even when power supply outstrips demand. For example:
>
> - For technical and cost recovery reasons, nuclear plant operators try to continuously operate at full power.
> - Eligible generators can take a 2.2¢/kWh or $22/MWh[yyy] production tax credit (PTC) on electricity sold. This means that some generators may be willing to sell their output for as low as -$22/MWh to continue producing power. Typically, wind generators are the largest such group in any region.
> - There are maintenance and fuel-cost penalties when operators shut down and start up large steam turbine (usually fossil-fueled) plants as demand varies over a day or a week. These costs may be avoided if the generator sells at a loss to attract a buyer when demand is low.[392]

As EIA notes, the PTC can create an incentive for wind generators to bid at negative prices. If other generators located at nodes in the areas affected by negative prices are unable or unwilling to reduce output, they will have to pay the negative price for their output. That scenario has unfolded on some buses in PJM, as outlined in comments to DOE from PJM staff:

> Tax and subsidy policies have had an impact on the economics of certain types of generation. The Renewable Energy Production Tax Credit and renewable energy mandates have had the most significant impact on nuclear generation. Specifically, the nuclear and wind generation are competing to clear in the market during off-peak hours when wind resources are the strongest and load is reduced. In those off-peak hours, the production tax credit has created an incentive for renewable resources to bid negative prices as they must run in order to receive their payment from the federal treasury. Since 2014, PJM has seen prices go negative at nuclear unit buses in approximately 2,176 hours—representing 14 percent of off-peak hours.[393] [footnotes omitted from original text]

[yyy] While the PTC value was $23/MWh in 2016, this figure was based upon EIA's interpretation of the PTC benefit at the time. https://www.eia.gov/todayinenergy/detail.php?id=8870

ERCOT's market monitor identified 130 negative-priced hours for the entire system in 2016, an increase from 50 hours in 2015.[394] Negative prices in ERCOT are now on the rise due to subsidized wind, as noted by William Hogan and Susan Pope in a recent study filed with the PUC of Texas by Calpine and NRG:

> Prior to the increase in wind and other intermittent capacity in the ISOs, negative prices sometimes occurred in the middle of the night, as load dropped and generators needed for operation the following day were pinned at their minimum loads. In contrast, the increasing incidence of negative prices in ERCOT is caused by the incentive of the owners of wind generation capacity receiving the PTC to continue to produce even when the locational price is negative.[395]

In addition to the PTC, VRE may also be incentivized to submit negative bids into markets by demand for RECs (to satisfy state environmental mandates and/or corporate sustainability goals).

Conventional generators also face economic factors that lead them to submit negative bids. Existing nuclear plants in the United States, as well as some fossil units, may bid in during these periods to avoid costly start-ups and shutdowns.[396] For example, steam turbine plants may choose not to cut back their production if they are not designed to cycle economically.

Operational attributes can also create or exacerbate negative prices. For example, hydroelectric plants are limited in their ability to curtail output because of environmental and safety reasons. Flood control and wildlife regulations are two important reasons this can take place. As this winter's record precipitation gave way to snowmelt this spring, CAISO found itself with an abundance of un-curtailed hydroelectricity that competed with solar generation.[397] A similar dynamic played out in 2011 following significant precipitation in the Pacific Northwest, as shown in Figure 5.8.[zzz]

[zzz] In Figure 5.8, Off-peak is 10 p.m. to 6 a.m. on Monday through Saturday and all hours on Sunday. Mid C is Mid-Columbia, COB is California-Oregon Border, and NOB is Nevada-Oregon Border.

Figure 5.8. Negative Northwest Off-Peak Daily Spot Prices ($/MWh) in 2011[398]

5.3.3 State Actions Impacting Wholesale Markets

There is growing concern about the impact of state government intervention in wholesale markets, such as the creation of ZEC programs to keep nuclear plants in operation, as well as RPS and other state policy requirements. This concern was reflected in comments at the May 1–2, 2017 FERC Technical Conference on state policies in the three eastern wholesale markets:[aaaa]

> [Roy Shanker, independent consultant]: It is difficult to identify any element in the wholesale electric market (energy, capacity, ancillary services and transmission) that is not being directly and materially impacted by discriminatory mandates driven by state policy actions. Price taking energy and capacity offers linked to these mandates directly impact price formation. The intermittent nature of virtually all RPS resources requires material modification of dispatch and significant increases in flexible resources and associated ancillary services.[399]
>
> [William Hogan, Harvard University]: The increasing impact of Federal and state policies to support particular technologies, raises questions about the viability of wholesale power markets.[400]
>
> [Susan Tierney, Analysis Group]: These state policies can and often do affect the price of electricity in wholesale power markets, and the entry, exit and cost of operations of electric generating resources…there is no reason to expect that state decision makers will make

[aaaa] The full transcript of (and all written statements from) this technical conference is available on FERC's website. FERC Technical Conference, "Docket No. AD17-11-000", May 1-2, 2017.

> determinations that singularly focus on economic efficiency and the continued viability of wholesale capacity-market designs ahead of other all objectives… Already, we see that in a market that depends upon the flow of private capital and diversity in the asset mix, some suppliers of capacity resources (including demand-response and nuclear generation) have recently decided that the markets are not producing financial outcomes consistent with the requirements of private capital markets… I remain concerned that the current centralized wholesale capacity markets in PJM, NYISO and ISO-NE will not be sustainable, from an economic, financial and political point of view and in light of states' policies and preferences.[401]
>
> [Cliff Hamel, Navigant Consulting]: [P]roblems in the current centralized [capacity] market approach are fundamental.[402]
>
> [Samuel Newell, The Brattle Group]: The centralized wholesale markets do not, however, and should not be expected to meet goals they were not designed to meet. Many states now have far-reaching carbon and clean energy goals. Yet today's centralized energy, ancillary services, and capacity markets are mostly not designed to differentiate generation resources based on their unpriced carbon emissions or other unpriced attributes.[403]
>
> [Lawrence Makovich, IHS Markit]: In summary, out-of-market interventions cause predictable distortions and consequences, including:
>
> 1. Reduced market-based cash flows for non-peaking generating resources, causing lower investment in electric generating production efficiency.
>
> 2. Uneconomic displacement of lower cost energy production causing a shift toward a less cost-effective fuel and technology mix and resulting in higher overall average electricity supply costs.
>
> 3. Less supply diversity causing more generation production cost and availability risk.
>
> 4. Premature retirements of low CO2 emitting resources, causing replacement with higher CO2 emitting resources that subvert market intervention policy goals.[404]

While this panel of economists commented on these effects on the wholesale markets resulting from state policies, members of a panel of state officials at the same FERC Technical Conference clearly said their states will continue to pursue their policies:

> [Jeffrey Bentz, New England States Committee on Electricity]: States aren't interested in having markets just for the sake of having markets…[405]
>
> [Angela O'Connor, Department of Public Utilities of Massachusetts] […] what the legislature requires us to do we have to do…[406]
>
> [Sarah Hofman, Vermont Public Service Board]: […] we cannot tell what our legislators [what to] do. And so they are going to have policies and it doesn't matter what anybody here or any place else says, they will have policies that set the stage for what the state wants and that's what legislators are for.[…] there is no question that state lawmakers will continue passing legislation that sets public policy. It is now our challenge to continue to work together to find effective ways to carry out those policies while also continuing to benefit from competitive wholesale markets.[407]

Tony Clark recently expressed similar views on the original policy assumptions behind the creation of centrally-organized wholesale markets:

> Affordable power was the goal. The current markets are still procuring affordable power but many state public policy makers no longer see that as the only goal. It is little wonder we hear some decry that the markets are not delivering what people want. It is because they were never designed for job creation, tax preservation, politically popular generation, or

> anything other than reliable, affordable electricity. To the degree policy makers and elected officials have moved the goal posts, it is time to consider rational pathways forward.[408]

5.4 Wholesale Electricity Markets Looking Forward

Changes in the centrally-organized markets must catch up to the broad technology-driven and policy-driven electricity market dynamics identified in the April 14 memo. Overall, centrally-organized wholesale electricity markets are effective at driving energy prices toward suppliers' short-run marginal costs. However, the revenue insufficiency problem has become more pronounced in recent years.

Generator profitability could become a public policy concern if so much generation is financially challenged that the reliability or resilience of the BPS become threatened. New market structures may be necessary to reflect these market dynamics, particularly in an industry in which suppliers with high fixed capital costs and relatively low marginal costs often struggle to recover their long-run average costs.

In addition, while markets as currently designed do not explicitly recognize or compensate system resilience, RTO/ISOs are considering ways to better support system resilience objectives in the same way that they explicitly recognized and administratively incorporated reliability standards into dispatch practices in the past. For example, the variety of problems that arose during the Polar Vortex (as discussed in Section 4) caused PJM and ISO-NE to change their capacity market rules to ensure generator performance during scarcity conditions.[409] [410]

In summary, the debates surrounding wholesale markets are complex and multifaceted, but the institutions and the grid itself have historically proven flexible, strong, and able to adapt. Questions about revenue sufficiency and resilience must be addressed quickly, before the fast-moving evolution of our power system outpaces our ability to understand and manage it responsibly.

6 Affordability

The April 14 memo asked whether the loss of coal, natural gas, nuclear, and hydroelectric baseload power is making the grid less affordable. There is no widely accepted metric for an "affordable" grid or an "affordable" electricity bill. DOE's GMI defines affordability as "maintain[ing] reasonable costs to customers."[411] Typically, the meaning of "affordable" is contextual, i.e. dependent on the size of a consumer's household budget. This indicator of energy affordability can be represented as *energy burden,* which is a household's annual spending on energy as a percentage of its gross annual income.[412] [413]

Because electricity is an important energy service, it can be broken out as "electricity burden."[bbbb] In 2011, the median electricity burden for all households was four percent, but it averaged 8.3 percent for low-income households and 2.9 percent for non-low-income households.[414] [415] [416] For low-income families, more spending on energy bills translates into less spending on other expenses, such as food, health care, and education.[417] The limited increases in electricity rates suggest that electricity bills have not become less affordable for most customers. However, changes in cost allocation and rate designs could have disparate effects on bills for different groups of customers.

For example, utilities raising fixed charges to counterbalance decreases in revenues from energy efficiency gains could disproportionately impact low-consumption customers, for whom fixed charges comprise a larger portion of the bill. Customers on fixed incomes and those who rely on electricity-intensive medical devices may have an acute need to maintain affordability.[418] Most states and utilities offer programs like concessionary rates for these customers, and ensuring affordability options for vulnerable customers remains a priority as electricity stakeholders explore market, regulatory, and rate reforms to accommodate an evolving grid.

Low electricity prices can also boost businesses' competitiveness and bring new economic activity to an area, as evidenced by companies locating electricity-intensive industrial facilities, such as server farms, to regions with low, stable electricity prices.[419] [420] [421] [422] Today, many businesses are more actively managing their energy costs by investing heavily in energy efficiency, energy management systems, solar PV installations, and direct PPAs with VRE providers.[423] Industrial electricity prices are typically close to wholesale prices because providing electricity to high-voltage, high-use industrial customers is less expensive and more efficient than serving distribution-level customers.[424] Thus, low wholesale electricity prices can allow businesses and industrial customers to thrive, support job growth, and drive economic development.[425]

6.1 Affordability of Generation Portfolios

The affordability of a given generation portfolio is largely shaped by region- and state- specific market structures. Merchant investment decisions (where applicable) and regional resource availability (for example, NGCC has a lower levelized cost of electricity (LCOE, the per-MWh cost of building and operating assets over their lifetime) in the Gulf States where gas is abundant than it has in the North

[bbbb] However, this is complicated by the fact that electricity usage varies significantly from region to region, so the electricity burden would be much higher in regions that use electricity for heating and cooling, as is common in the West and South. In addition to electricity, *energy* burden includes direct fuel use, such as natural gas or propane for cooking and heating, and can vary based on a household's activities, appliances, and location.

Central states) contribute to regional variation in charges to end-users. [426] The Energy Information Administration estimated in the Annual Energy Outlook for 2017 that the BPS (generation and transmission) comprises roughly two-thirds of the total average price of electricity. Generation costs accounted for 57 percent of the average price of electricity in 2016, compared to distribution's 32 percent and transmission's 11 percent.[427]

In vertically integrated areas, state PUCs seek to avoid uneconomic outcomes and ensure affordable service to customers[428] by requiring VIEUs to submit IRPs in which they consider least-cost, long-term plans for providing service including, among other things, LCOE.[429] The IRP must also account for any additional state-mandated requirements such as energy efficiency resource standards or RPS.[430] Notably, VIEU assets are usually guaranteed the recovery of investment and operational costs regardless of whether they would prove to be cost-competitive in a short-run marginal cost market environment.[431] [432]

By contrast, in some of the centrally-organized markets (e.g., most of the states in PJM, ERCOT, all but two in ISO-NE, NYISO, and Illinois for MISO), the generation portfolio is determined by the wholesale market itself (subject to any generation and demand-side mandates) rather than a state-overseen IRP by the VIEU.[cccc] Merchant generators make investment decisions by comparing an asset's expected lifetime costs with the expected revenues from any PPAs, financial incentives such as tax credits, and sales in wholesale energy and capacity markets. Lifetime costs considered by merchant generators include fixed investment costs and operational costs.

6.2 The Wholesale-Retail Disconnect

Tracing the relationships between wholesale and retail prices is difficult because ratemaking practices vary widely from state to state, and there are many other contributing factors involved besides the wholesale cost of electricity.[433] [434] Retail rates include a variety of charges that are not included in the bulk electricity charges passed through by RTO/ISOs or VIEUs. These include components of the transmission costs not captured in the RTO prices (such as state-regulated transmission investments), payments that the distribution utility makes to merchant transmission suppliers, various fixed charges, customer service, state and local sales taxes and franchise fees, and public benefits charges.[435]

Retail electricity bills can also include additional costs to support state policy goals—such as RPS, energy efficiency resource standards, or programs to promote use of distributed energy resources, among others.[436] Most utilities have undertaken substantial programs to modernize their distribution systems, and a significant subset have invested in infrastructure needed to integrate higher levels of distributed energy resources.[437] Under established cost-of-service ratemaking principles, these costs are typically allocated to retail customers and periodically examined by regulators.

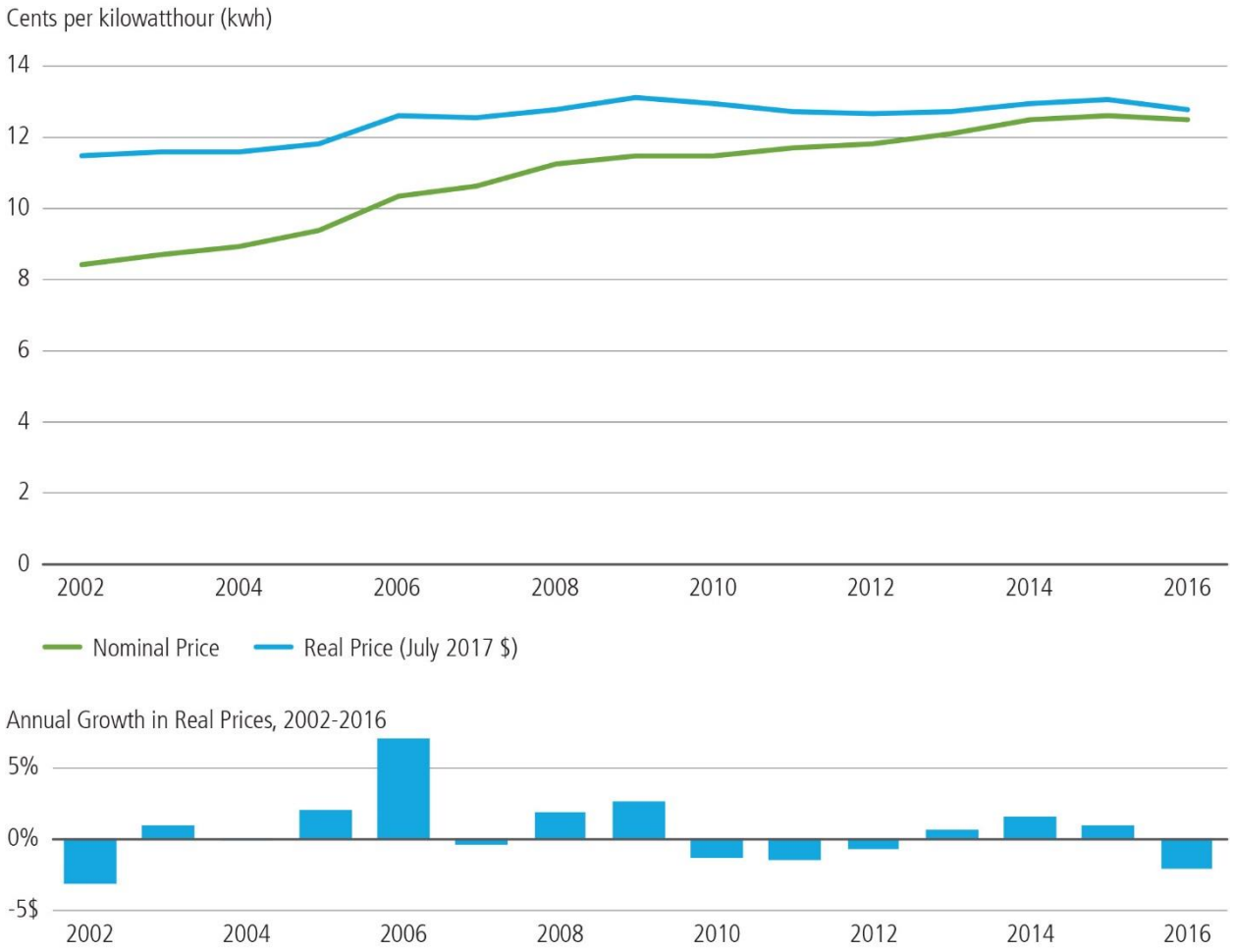
The wholesale-retail electricity price disconnect means that, in most areas, the conventional generation retirements can affect wholesale rates but have little or no immediately visible impact on retail rates.

[cccc] Many state, regional, and Federal policies can impact the expected profits for merchant generators, including environmental regulations; carbon trading programs; tax credits; and state procurements, mandates, or other mechanisms that take generation or demand-side resources out of markets available to merchants and/or subsidize those resources.

However, despite the difficulty in attributing retail price impacts to wholesale changes, considering the trends in both wholesale and retail prices can provide greater understanding of affordability.

On average, national retail electricity rates have been roughly flat for more than a decade, and rates have closely followed the historical average since 1960.[dddd 438] Retail rates in nominal dollars have been increasing at a low annual rate for approximately two decades, while the real retail price has stayed relatively constant over the last decade, as shown in Figure 6.1. From 2011 to 2016, nominal residential prices increased at an average of 1.9 percent annually, about the same rate as overall inflation.[439] In 2016, the national average retail electricity price declined for the first time since 2002, with residential customers paying a national average of 12.55 cents/kWh.

Figure 6.1. Average U.S. Residential Sector Retail Electricity Prices over Time[440]

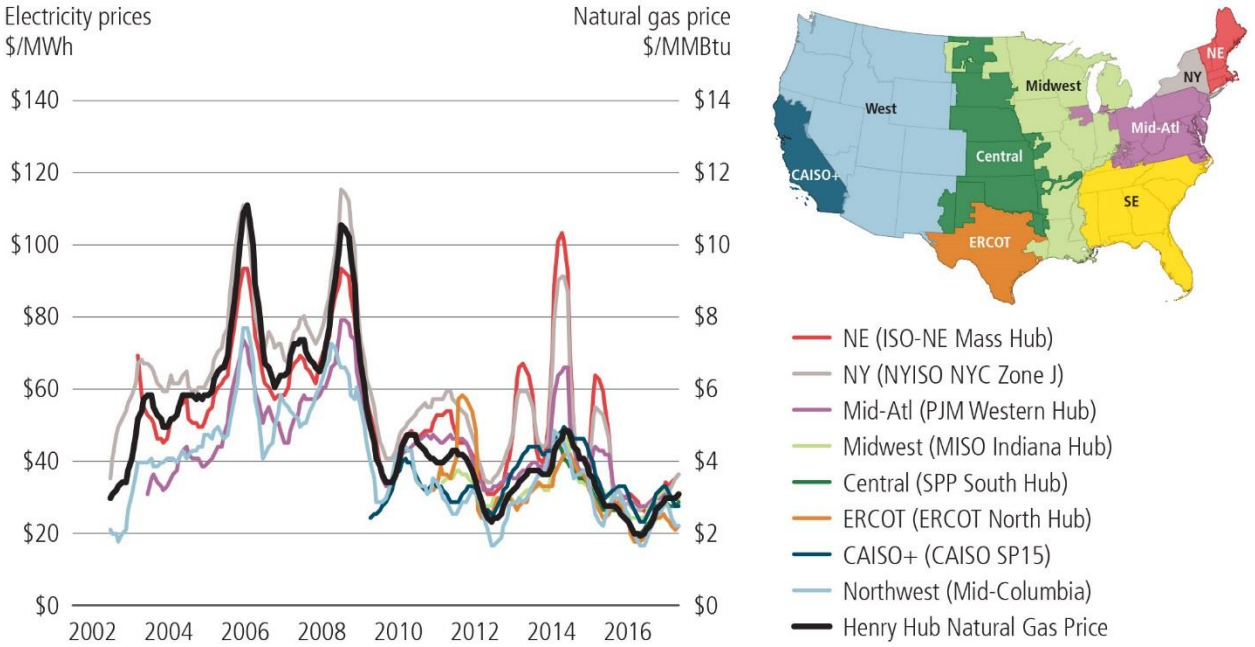


[dddd] The use of national averages for this analysis provides a broad picture, but limits insight into regional and state-level impacts of BPS changes that may lead to higher-than-average retail rate increases among some customers and utilities. National averages mean little to subsets of ratepayers seeing significant retail rate increases or those who have faced consistently high bills. Even use of state-level retail averages can mask exceptions that greatly vary from the average. For example, California residents who live near the coast enjoy a temperate climate with limited need for cooling or heating. In contrast, those living inland see very hot summers that require high use of air conditioning and thus see high electric bills. A more thorough analysis would consider affordability and rate increases at a more granular level.

Average retail prices vary widely across states and regions, with New England, California and the Mid-Atlantic paying the highest rates.[441] However, a comparison of electricity rates alone can be misleading; for instance, California's average residential electricity rate is over 18 cents/kWh (one of the highest in the Nation), but due to low average residential consumption, the average California electricity bill is only $95/month, ranking it in the bottom third of the Nation. By comparison, Washington state has the lowest average retail rates in the Nation at less than nine cents/kWh (less than half the average rate in California), but because of higher consumption, residential customers in that state see average bills of $95/month, the same average electricity bill as in California.[442] [443]

It is not yet clear what impact recent coal, nuclear, and natural gas plant retirements will have on customer bills in the future, nor how the continuing trend of retirements will affect the overall cost of the BPS, which will ultimately be borne by ratepayers. Natural gas generation has proven to be a strong competitor with coal and nuclear power because natural gas prices have fallen over the past decade. Wind and solar generation have also increased, and while their capital costs are much higher than those of natural gas (particularly if normalized by capacity factor), their marginal cost is nearly zero.[444] Changes in the BPS since 2002—lower demand, lower natural gas prices, and growth in VRE—have reduced wholesale electricity prices, as shown in Figure 6.2.[445]

Figure 6.2. Average Wholesale Electric Costs/MWh Have Fallen between 2002 and 2016[446]

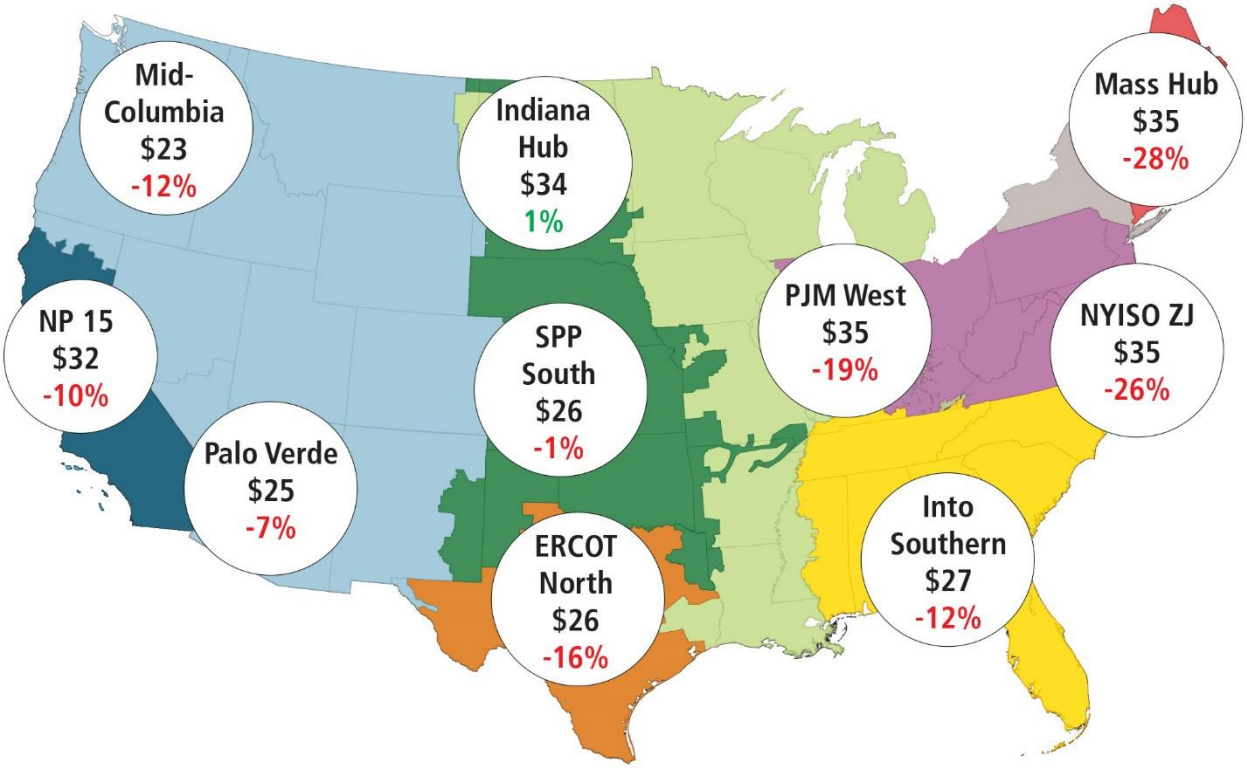


From 2002–2016, wholesale electricity prices have increasingly tracked natural gas prices, and as natural gas generation has increased over time, the differences in price between regions have also decreased (e.g., prices in NYISO and PJM are much closer in 2016 than in 2004).

Figure 6.3 illustrates wholesale prices at electricity trading hubs, emphasizing 2016 prices on a regional basis as derived by FERC staff.[eeee] FERC notes in its 2016 *State of the Markets* report that prices were down in 2016 from 2015, and that prices in PJM were the lowest they have been since the RTO formed in 1999.[447]

[eeee] Derived by FERC staff from S&P Global Intelligence data. Prices are a simple average of day-ahead, on-peak physical prices.

Figure 6.3. Day-Ahead, On-Peak Wholesale Electric Prices Reach Near-Record Lows in 2016[448]



FERC's most recent *State of the Markets* report shows that all areas of the United States are experiencing low wholesale electricity prices. In 2016, prices were highest in the Northeast, Mid-Atlantic, and Midwest and were lowest in the Northwest. Historically, wholesale prices would show much more regional variation. The dollar values are average 2016 day-ahead on peak prices; the percentages indicate the change from 2015 to 2016.

While wholesale electricity prices have tracked natural gas price trends, the impacts of other generation trends on affordability are less obvious.[449] Because coal, hydro, and nuclear plants have historically had relatively stable and predictable fuel costs, these power plants have provided a valuable hedge against the price volatility of natural gas and oil. Today, nuclear, hydro, and VRE all serve as hedges against generation whose fuel cost is more volatile and represents a larger portion of the total delivered price (i.e. natural gas and oil). For example, the variable operating, maintenance, and fuel costs of hydroelectric and nuclear average just $5/MWh and $12/MWh, respectively, compared to $41/MWh for NGCC and $34/MWh for coal.[450] Increasingly, VRE also performs a price stabilizing role—wind, solar PV, hydropower, and geothermal generation offer near zero-marginal-cost electricity. To the degree that VRE and nuclear can stabilize the short run cost of bulk power, those resources could also improve the month-to-month manageability of customer bills.

Among the nine regions examined in this study, the CAISO+, Midwest, ERCOT, and Central regions have the most non-hydro VRE generation today. RPS compliance costs were found to total $2.6 billion in

2014, averaging $12/MWh for VRE and equating to 1.3 percent of average retail electricity bills.[ffff] [451] The actual effects of zero-marginal cost electricity on consumers' bills is situational, and growth in VRE can drive additional costs, including transmission and integration costs.[452] [453] Because many utility-scale VRE plants are built in locations distant from load centers, they sometimes require major transmission additions to connect the remote generation to the rest of the grid and to load centers. Over the past five years, a portion of the 24,000 miles of new transmission built (about twice the number of miles added from 2006–2010) and $102 billion invested to strengthen the grid and interconnect new generation has been made to interconnect VRE.[454] [455] Transmission investments (regulated or merchant) can increase bulk power costs and therefore increase customers' retail bills to the extent that they are not offset by savings attributable to access to lower-cost generation or reduced congestion costs.

Higher levels of VRE penetration also require system integration services, such as additional ERS. It is unclear how the costs of these integration requirements will affect wholesale electricity costs as VRE penetrations continue to increase. In addition, as the PTC for wind generation expires and the ITC for residential solar PV installations reduces in the coming years, their costs relative to other resources will rise. However, declining wind and solar capital costs and higher productivity will likely somewhat offset these losses, albeit to an unknown degree.[456] [457] [458] [459]

Finally, several states have created subsidies to favor or retain nuclear generation. If such subsidies are being funded by taxpayer dollars – like the PTC and ITC – rather than a charge to electricity customers, this will affect wholesale costs in some way, but will probably have little discernable effect on the customers' retail electricity bills. However, if subsidies for power plant retention are funded as a direct charge to retail electricity customers, electricity bills could rise and affordability could decrease.

Overall, ISOs and RTOs face many challenges that ultimately affect the allocation of transmission and integration costs when they make decisions on how to spread those costs among cost-causers, reliability and other service providers, and consumers, as well as decisions on how to keep cost allocation practices up to date as the generation mix, transmission capacity, and load evolves over time.[460] [461] [462] [463]

6.3 Affordability Looking Forward

There appears to be little near-term risk that natural gas prices will rise significantly and thereby reduce electricity affordability. However, natural gas is an extractive commodity traded internationally—prices are affected by policies impacting how the resource is produced, and prices show periodic regional, seasonal, or local price spikes, and even sustained price increases. It is reasonable to expect continuing regional differentials between natural gas delivered costs, reflecting differences in proximity to natural gas production fields, production costs, and deliverability (including the effects of pipeline or liquefied natural gas deliverability constraints). If natural gas prices rise, wholesale electricity costs are likely to rise in regions where natural gas remains the marginal fuel in a significant number of hours. This would be true for both RTO/ISO and non-RTO/ISO regions. It is unclear how rising natural gas prices and

[ffff] Studies on RPS compliance costs do not fully capture the "all-in" costs that the ratepayer (and taxpayers) ultimately bear. These other costs are harder to measure, but may not be insignificant. They may be harder to quantify for many reasons, such as having multiple drivers behind those investments and various distribution-level grid modernization investments (e.g., smart meters and others that are touted to aid VRE integration). New transmission (other than the direct transmission interconnection charged to the renewable generation project and thus reflected in their PPA), as well as effects of VRE variability on the dispatchable fleet, are other examples of costs often not included in grid integration cost studies. Costs of various tax and other subsidies are also not counted.

additional VRE generation would affect the large-scale displacement of coal and nuclear generation, and ultimately, electricity affordability for affected consumers.

The variety of generation portfolios operating throughout the U.S. lends itself to further study. To date, limited work has focused on the affordability of the BPS as a system or portfolio—relatively more attention has focused on retail electricity prices[464] or the stand-alone cost of generation technologies (such as LCOE). Some research has focused on analysis of system-wide LCOE,[465] but more can be done.

Looking forward, another potential challenge to affordability is determining how the proliferation of distributed PV across much of the Nation is changing the cost structure for non-participating customers. A growing body of research considers whether and how distributed PV users continue to benefit from their grid connection for balancing services and energy storage, as well as how to reallocate utility energy, capital, and system costs and rates fairly among all users. Concerns about more customers installing distributed PV under net metering tariffs,[gggg] which potentially shifts costs and increases the burden on non-distributed PV customers, have caused multiple states to re-open their net metering tariff processes and, in some cases, implement new policies. However, some studies have quantified the retail rate impacts of net metering to all residential customers (i.e., participants and non-participants) and found that current and projected levels of net metering have very little impact, especially compared to broader drivers of retail rate increases in the electric industry.[466]

[gggg] According to the EIA, "net metering tariffs enable customers to use the electricity they generate in excess of their consumption at certain times to offset their use of electricity from the grid at other times. These tariffs are designed to encourage distributed renewable generation. These arrangements describe how an electric utility customer who installs a qualifying generator (typically a rooftop solar array, less often a small wind turbine, or a small combined heat-and-power system) will be compensated by their utility for the electricity they generate in excess of their consumption." https://www.eia.gov/todayinenergy/detail.php?id=6190

7 Policy Recommendations

The April 14 memo asked staff to "not only analyze problems but also provide concrete policy recommendations and solutions." To that end, DOE staff prepared a list of recommendations below. Some actions fit squarely within DOE's authority, while others might fall to other government agencies or private organizations.

Wholesale markets: FERC should expedite its efforts with states, RTO/ISOs, and other stakeholders to improve energy price formation in centrally-organized wholesale electricity markets. After several years of fact finding and technical conferences, the record now supports energy price formation reform, such as the proposals laid out by PJM[467] and others.[468] Further, negative offers should be mitigated to the broadest extent possible.

Valuation of Essential Reliability Services (ERS): Where feasible and within its statutory authority, FERC should study and make recommendations regarding efforts to require valuation of new and existing ERS by creating fuel-neutral markets and/or regulatory mechanisms that compensate grid participants for services that are necessary to support reliable grid operations. Pricing mechanisms or regulations should be fuel and technology neutral and centered on the reliability services provided. DOE should provide technical and policy support that strengthen and accelerate these efforts.

Bulk Power System (BPS) resilience: DOE should support utility, grid operator, and consumer efforts to enhance system resilience. Transmission planning entities should conduct periodic disaster-preparedness exercises involving electric utilities, regional offices of Federal agencies, and state agencies. NERC should consider adding resilience components to its mission statement and develop a program to work with its member utilities to broaden their use of emerging ways to better incorporate resilience. RTOs and ISOs should further define criteria for resilience, identify how to include resilience in business practices, and examine resilience-related impacts of their resource mix.

Promote Research and Development (R&D) of next-generation/21st century grid reliability and resilience tools: DOE should focus R&D efforts to enhance utility, grid operator, and consumer efforts to enhance system reliability and resilience. DOE R&D opportunities include the following activities:

- Develop grid technical tools to facilitate new-generation technologies' operations to support BPS reliability (e.g., by enabling technologies to provide ERS), and maximize use of the DOE national laboratories.
- Expand cooperation on grid reliability across North America, including working with NERC to further enhance the reliability of our shared BPS through technical engagement with Mexico and Canada.
- With the National Science Foundation, sponsor the development of new open-source software for the next-generation electric grid research community.
- Focus R&D on improving VRE integration through grid modernization technologies that can increase grid operational flexibility and reliability through a variety of innovations in sensors and controls, storage technology, grid integration, and advanced power electronics. The Grid Modernization Initiative should also consider additional applications of high-performance computing for grid modeling to advance grid resilience.

Support Federal and regional approaches to electricity workforce development and transition assistance: In partnership with other agencies and the private sector, DOE should facilitate programs

and regional approaches for electricity sector workforce development. Unemployed workers nearing but not yet eligible for retirement may have difficulty retraining after careers built on specialized skills that may be in declining demand. Where possible, Federal agencies should leverage existing government, nongovernment, labor, and industry workforce consortia.

Energy dominance: Executive Order 13783 (Promoting Energy Independence and Economic Growth) outlined an approach to promote the clean and safe development of energy resources while at the same time minimizing regulatory barriers to energy production, economic growth, and job creation. The Order called for a rescission of certain energy and climate related policies, rescinded specific reports, and ordered the review of key environmental regulations. While DOE is not the main agency tasked in the Order, it should continue to prioritize energy dominance and implementing the Executive Order broadly and quickly.

Infrastructure development: DOE and related Federal agencies should accelerate and reduce costs for the licensing, relicensing, and permitting of grid infrastructure such as nuclear, hydro, coal, advanced generation technologies, and transmission. DOE should review regulatory burdens for siting and permitting for generation and gas and electricity transmission infrastructure and should take actions to accelerate the process and reduce costs. Specific reforms could include the following:

- *Hydropower*: Encourage FERC to revisit the current licensing and relicensing process and minimize regulatory burden, particularly for small projects and pumped storage.
- *Nuclear Power*: Encourage the NRC to ensure the safety of existing and new nuclear facilities without unnecessarily adding to the operating costs and economic uncertainty of nuclear energy. Revisit nuclear safety rules under a risk-based approach.
- *Coal Generation*: Encourage EPA to allow coal-fired power plants to improve efficiency and reliability without triggering new regulatory approvals and associated costs. In a regulatory environment that would allow for improvement of the existing fleet, DOE should pursue a targeted R&D portfolio aiming at increasing efficiency.

Electric-gas coordination: Utilities, states, FERC, and DOE should support increased coordination between the electric and natural gas industries to address potential reliability and resilience concerns associated with organizational and infrastructure differences. DOE and FERC should support well-functioning commodity markets for natural gas by expeditiously processing liquefied natural gas export and cross-border natural gas pipeline applications.

8 Areas for Further Research

DOE staff identified several research topics that are relevant to the April 14 memo and merit further in-depth analysis. Some topics may be appropriate for offices within the Department, national laboratories, academia, other government agencies, or private organizations.

Market structure and pricing

- Study mechanisms for enabling equitable, value-based remuneration for desired grid attributes—such as ERS, fuel availability, high resilience, low emissions, flexibility, etc.—with alternative market and non-market structures. This research could assess potentially under-recognized contributions from baseload power plants, using fuel-neutral metrics and values relevant to analyze all resource options.
- Evaluate ongoing capacity market reforms. Several of the Nation's electricity markets use mandatory capacity markets to procure capacity for future years and ensure resource adequacy. The design of these constructs has been the subject of near-constant debate within the RTO/ISOs and before FERC. After undergoing substantial changes from 2014–2015, capacity markets have come under new scrutiny in light of recent actions by restructured states to preserve or promote certain resources or resource types and to further state policy goals.
- Explore market operations in a higher VRE/low marginal cost system, and examine recent changes in energy price trends—including the drivers of wholesale electricity prices in the context of limited load growth—quantifying the relative contributions of fossil fuel prices. With significant amounts of near-zero marginal cost generation available, security-constrained economic dispatch of BPS based on marginal costs may not sufficiently compensate resources for all fixed and variable costs. Academic and other research should be expanded in this area, to include capacity market reforms and the role of capacity markets in a higher VRE/low marginal cost system.

Reliability and resilience

- Develop policy metrics and tools for evaluating BPS-wide provision of resilience and considering all aspects of the electricity system that contribute to resilience, including regional generation characteristics, imports and exports, fuel supply and storage, transmission capability, DR, electricity storage, inertia, and other factors that determine the ability of grid operators to provide reliable electricity supplies.
- As PJM notes, "criteria for resilience are not explicitly defined or quantified today."[469] Each RTO/ISO should strive to explicitly define resilience on its system and conduct resource diversity assessments to more fully understand the resilience of different resource portfolios. Federal, state, and local work to define and support system-wide resilience is also needed.
- EIA and NERC should examine ways to improve power generator fuel delivery data collection; additional data on fuel deliveries and potential disruptions would further improve forecasting necessary for electric reliability planning.

Cost and affordability

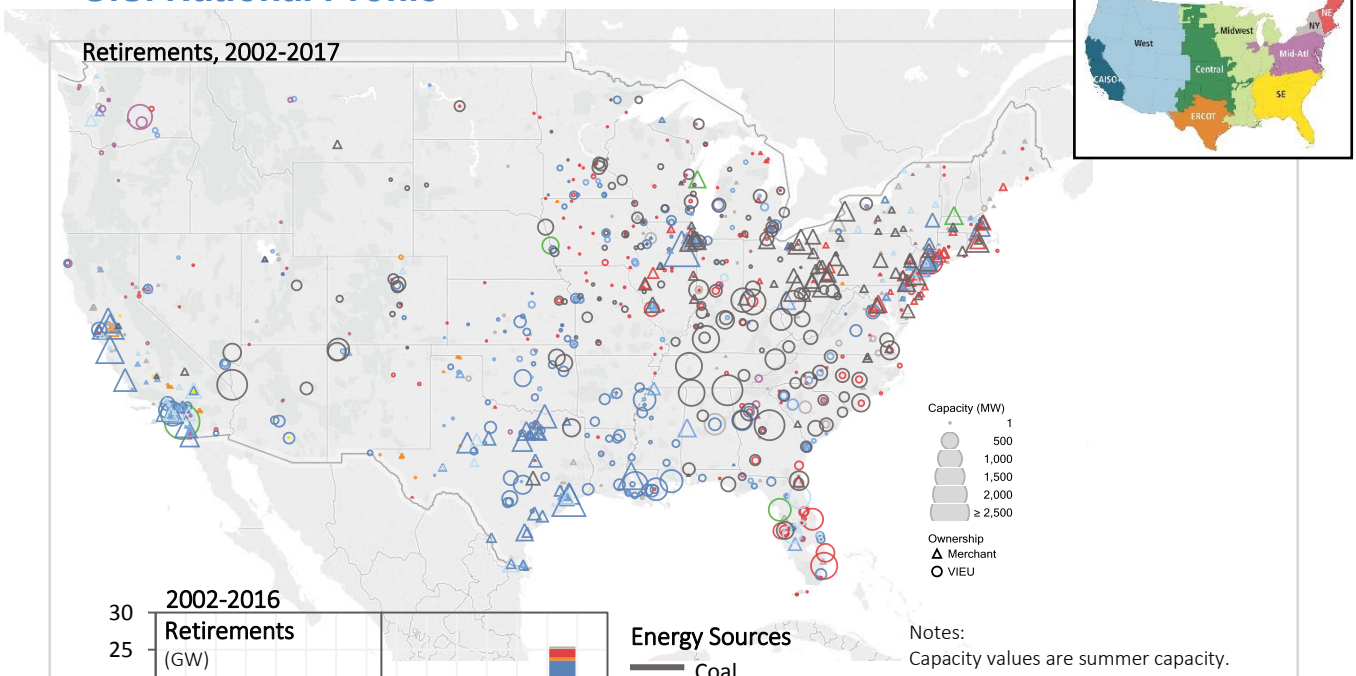
- Estimate the bulk power system-wide costs of different generation mixes, also considering the sensitivity of system costs to various fuel price fluctuations. Further, examine the relationship between wholesale and retail electricity rates to understand the present disconnect.
- On a regular basis, update the EIA analysis of subsidies and support for electricity production (most recently updated using FY 2013 data).[470]

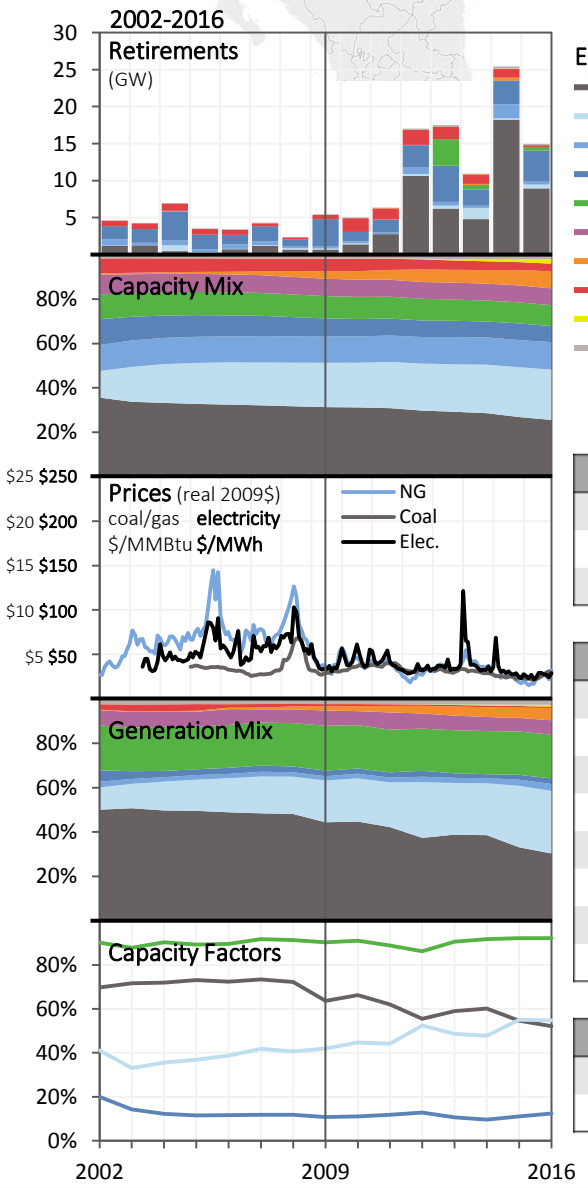
Regulatory

- Explore the potential for utilizing existing Federal authorities under the Federal Power Act and the DOE Organization Act, among others, to ensure system reliability and resilience.
- Explore costs and benefits of states applying cost-of-service regulation to specific at-risk plants that contribute to grid resilience. In centrally-organized wholesale markets, these resources may sometimes be unable to recoup all costs of generating electricity—especially capital investments that are needed to ensure long-term viability.

Appendix A: National and Regional Profiles

U.S. National Profile





Energy Sources

- Coal
- Natural Gas (CC)
- Natural Gas (CT)
- Natural Gas (ST)
- Nuclear
- Hydro
- Wind
- Oil
- Solar
- Other

Notes:
Capacity values are summer capacity. Data for utility-scale resources only (1+ MW nameplate capacity). Natural gas technologies: CC = combined cycle, CT = combustion turbine, ST = steam turbine. Ownership type: VIEU = vertically integrated electric utility. Map includes 2017 Q1 actual and Q2-4 announced retirements. Prices: Natural gas = Henry Hub, Coal = Central App., Electricity = PJM Western Hub.
*Total % Capacity Reduction calculation: retired capacity / (retired capacity + 2016 operational capacity)

Total Capacity & Generation

	2002	2016
Capacity (MW)	884,930	1,056,710
Generation (GWh)	3,860,853	4,085,765

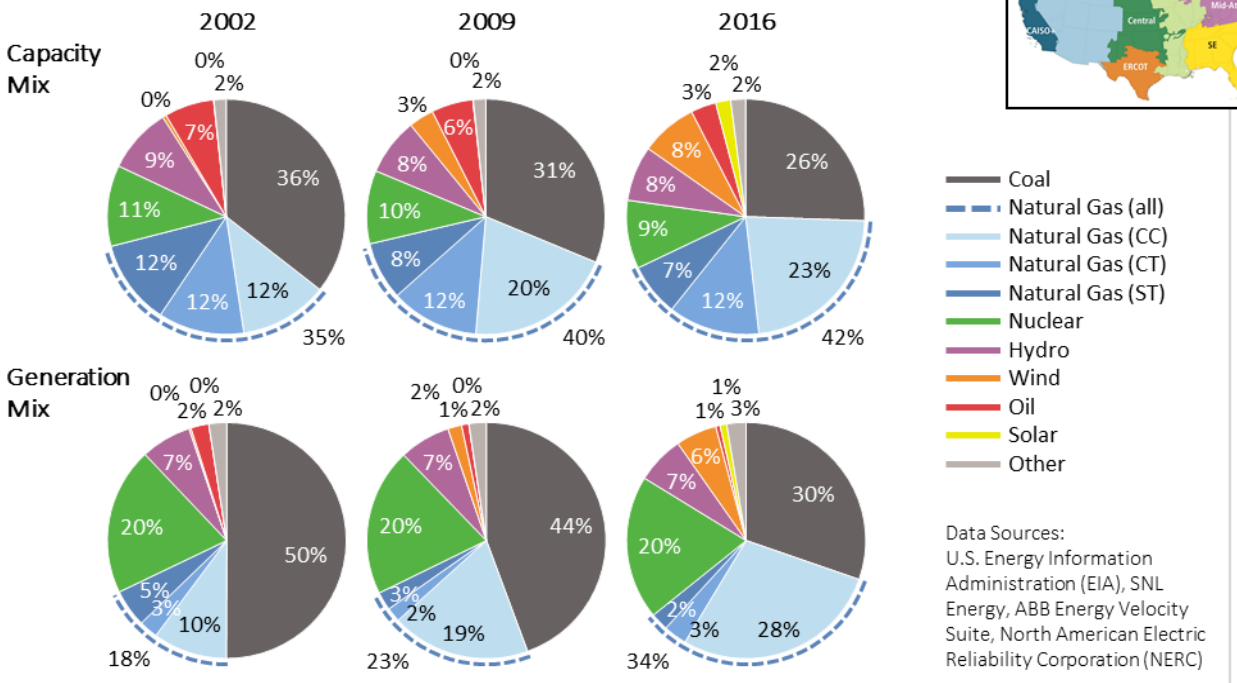
Retirements by Energy Source, 2002-2016

	# of Generators	MW
Coal	531	59,392
Natural Gas	965	50,593
Nuclear	6	4,667
Oil	1,083	14,980
Hydro	140	283
Other (all other sources)	471	2,147
*Total % Cap. Reduction**	*11.1%*	132,062

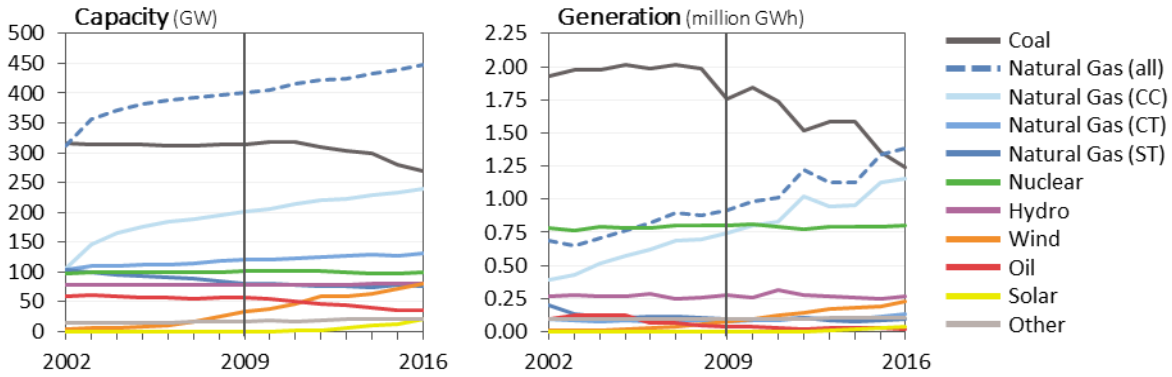
NERC Reserve Margin, 2017 (2016 LTRA)

	Target	Actual
Total NERC Area	--	23.58%

U.S. National Profile



Data Sources:
U.S. Energy Information Administration (EIA), SNL Energy, ABB Energy Velocity Suite, North American Electric Reliability Corporation (NERC)



Capacity & Generation by Energy Source, 2002 & 2016

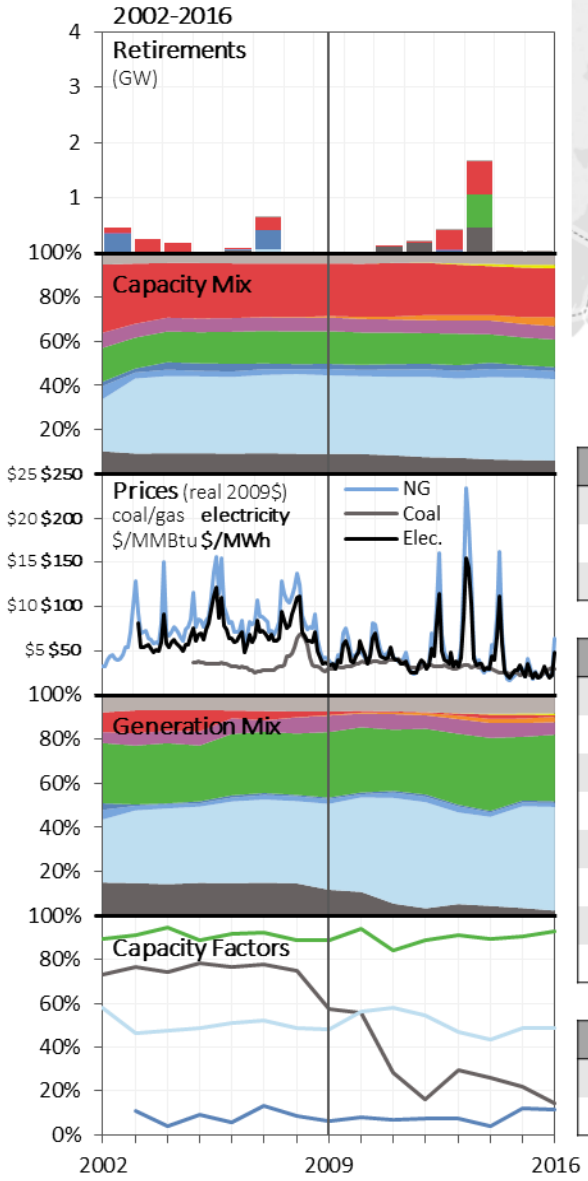
Energy Source	Capacity 2002 GW	%	Capacity 2016 GW	%	Generation 2002 thous. GWh	%	Generation 2016 thous. GWh	%
Coal	315.4	*36%*	270.1	*26%*	1,933.1	*50%*	1,240.1	*30%*
Natural Gas	312.5	*35%*	447.0	*42%*	685.4	*18%*	1,380.3	*34%*
Combined Cycle (CC)	106.1	*12%*	239.5	*23%*	387.7	*10%*	1,152.0	*28%*
Combustion Turbine (CT)	103.4	*12%*	131.0	*12%*	98.8	*3%*	129.6	*3%*
Steam Turbine (ST)	103.0	*12%*	76.4	*7%*	198.9	*5%*	98.6	*2%*
Nuclear	98.7	*11%*	99.3	*9%*	780.1	*20%*	805.3	*20%*
Hydro	79.4	*9%*	80.0	*8%*	264.3	*7%*	265.8	*7%*
Wind	4.4	*0%*	81.3	*8%*	10.4	*0%*	226.9	*6%*
Oil	59.7	*7%*	36.4	*3%*	94.5	*2%*	23.9	*1%*
Solar	0.4	*0%*	21.5	*2%*	0.6	*0%*	36.8	*1%*
Other	14.6	*2%*	21.2	*2%*	92.5	*2%*	106.7	*3%*
Total	**884.9**	*100%*	**1,056.7**	*100%*	**3,860.9**	*100%*	**4,085.8**	*100%*

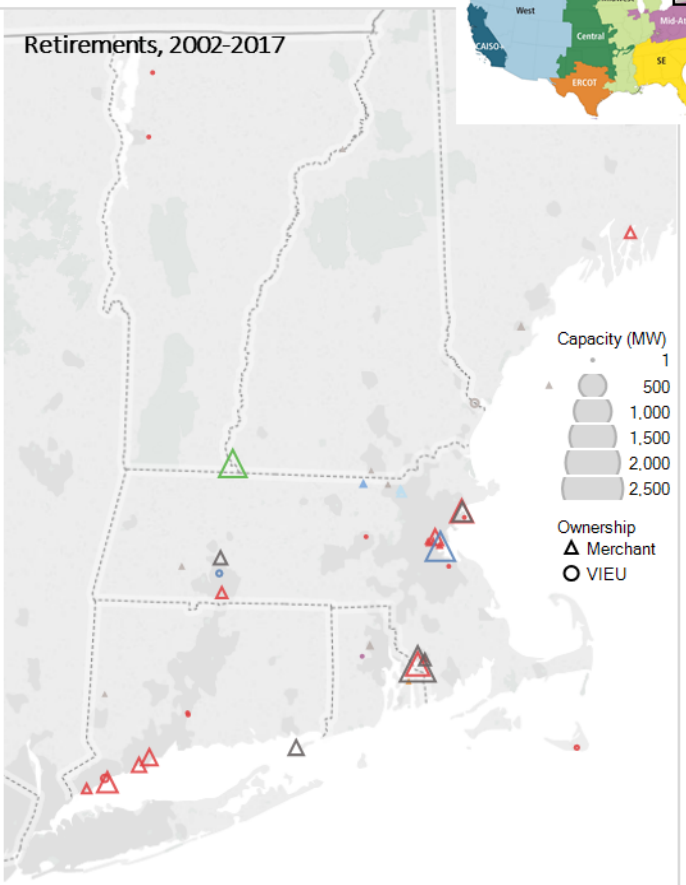
New England Regional Profile

Energy Sources

- Coal
- Natural Gas (CC)
- Natural Gas (CT)
- Natural Gas (ST)
- Nuclear
- Hydro
- Wind
- Oil
- Solar
- Other

Notes:
Capacity values are summer capacity. Data for utility-scale resources only (1+ MW nameplate capacity). Natural gas technologies: CC = combined cycle, CT = combustion turbine, ST = steam turbine. Ownership type: VIEU = vertically integrated electric utility. Map includes 2017 Q1 actual and Q2-4 announced retirements. Prices: Natural gas = Algon. Gates, Coal = Central App., Electricity = ISO-NE Mass Hub. *Total % Capacity Reduction calculation: retired capacity / (retired capacity + 2016 operational capacity)



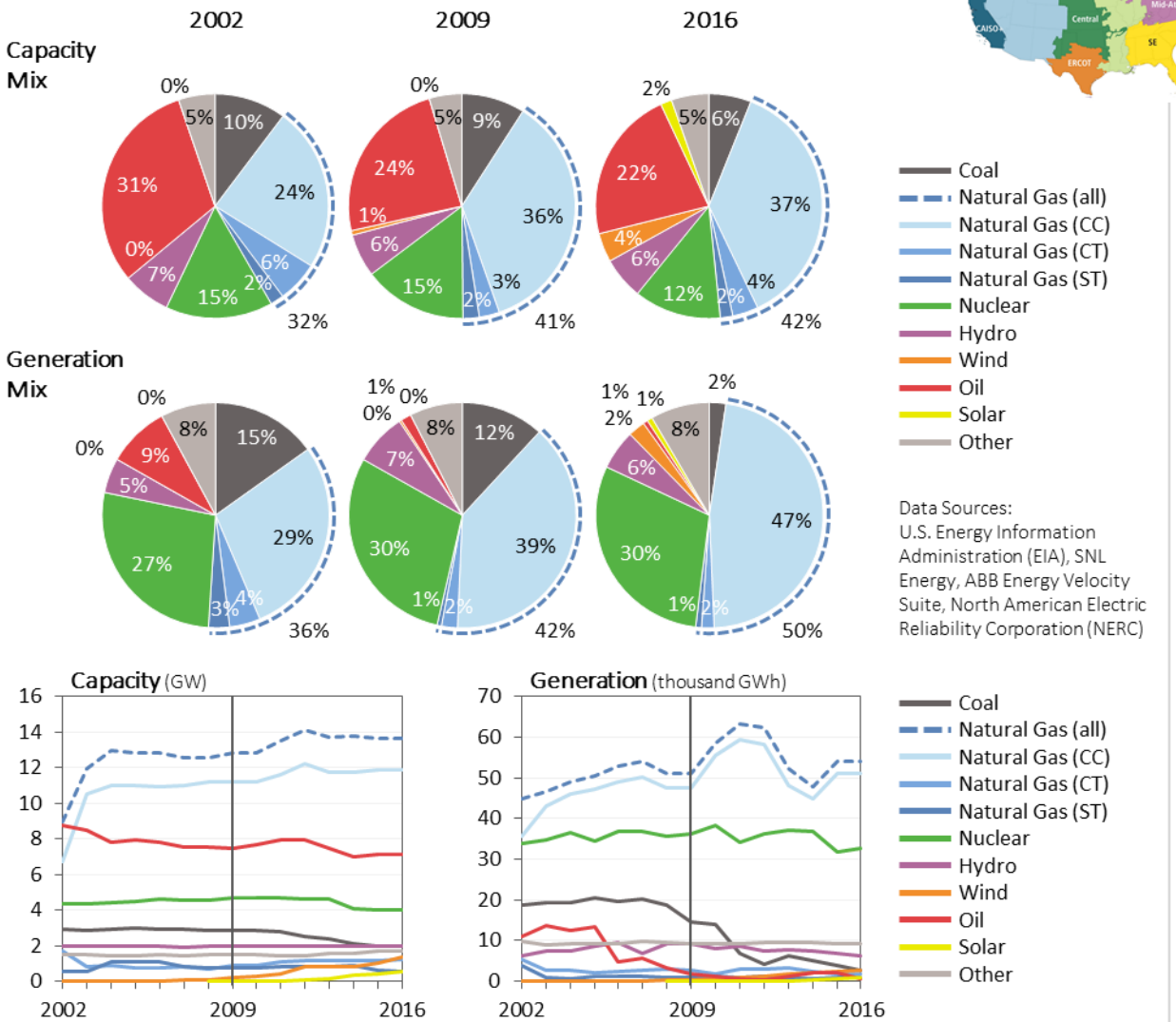


Total Capacity & Generation	2002	2016
Capacity (MW)	28,338	32,303
Generation (GWh)	124,613	108,802

Retirements by Energy Source, 2002-2016	# of Generators	MW
Coal	7	784
Natural Gas	14	837
Nuclear	1	612
Oil	74	1,808
Hydro	50	27
Other (all other sources)	45	140
*Total % Cap. Reduction**	***11.5%***	**4,209**

NERC Reserve Margin, 2017 (2016 LTRA)	Target	Actual
NPCC-New England	16.74%	20.32%

New England Regional Profile



Data Sources:
U.S. Energy Information Administration (EIA), SNL Energy, ABB Energy Velocity Suite, North American Electric Reliability Corporation (NERC)

Capacity & Generation by Energy Source, 2002 & 2016

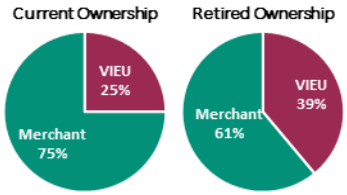
Energy Source	Capacity 2002 GW	%	Capacity 2016 GW	%	Generation 2002 thous. GWh	%	Generation 2016 thous. GWh	%
Coal	2.9	*10%*	2.0	*6%*	18.8	*15%*	2.6	*2%*
Natural Gas	8.9	*32%*	13.7	*42%*	44.8	*36%*	54.0	*50%*
Combined Cycle (CC)	6.7	*24%*	11.9	*37%*	35.6	*29%*	51.1	*47%*
Combustion Turbine (CT)	1.7	*6%*	1.2	*4%*	5.4	*4%*	1.9	*2%*
Steam Turbine (ST)	0.6	*2%*	0.6	*2%*	3.7	*3%*	0.9	*1%*
Nuclear	4.3	*15%*	4.0	*12%*	33.9	*27%*	32.8	*30%*
Hydro	1.9	*7%*	2.0	*6%*	6.2	*5%*	6.2	*6%*
Wind	0.0	*0%*	1.3	*4%*	0.0	*0%*	2.6	*2%*
Oil	8.7	*31%*	7.1	*22%*	11.1	*9%*	0.7	*1%*
Solar	0.0	*0%*	0.5	*2%*	0.0	*0%*	0.8	*1%*
Other	1.5	*5%*	1.7	*5%*	9.8	*8%*	9.1	*8%*
Total	**28.3**	*100%*	**32.3**	*100%*	**124.6**	*100%*	**108.8**	*100%*

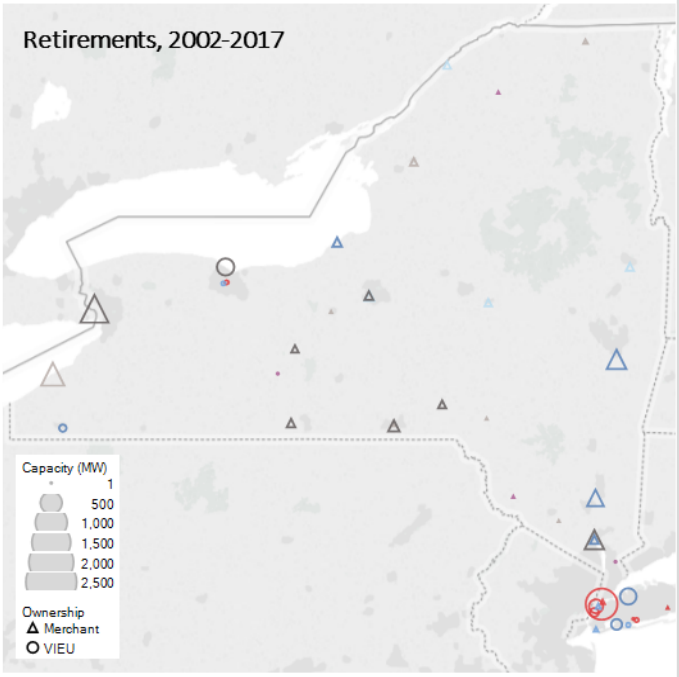
New York Regional Profile

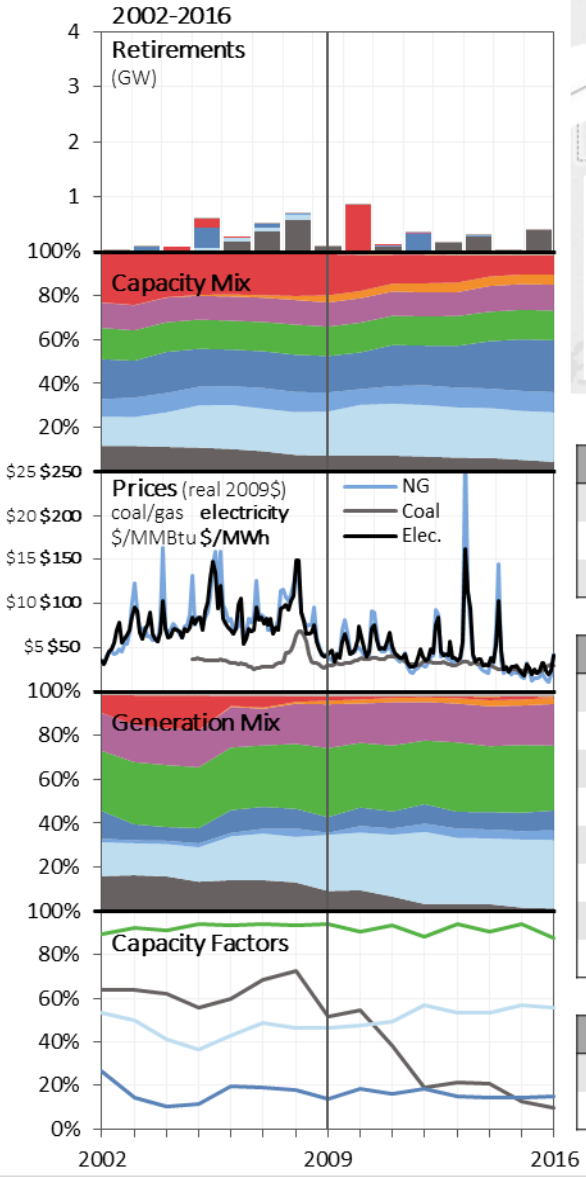
Energy Sources

- Coal
- Natural Gas (CC)
- Natural Gas (CT)
- Natural Gas (ST)
- Nuclear
- Hydro
- Wind
- Oil
- Solar
- Other

Notes:
Capacity values are summer capacity. Data for utility-scale resources only (1+ MW nameplate capacity). Natural gas technologies: CC = combined cycle, CT = combustion turbine, ST = steam turbine. Ownership type: VIEU = vertically integrated electric utility. Map includes 2017 Q1 actual and Q2-4 announced retirements. Prices: Natural gas = Transco Z6 NY, Coal = Central App., Electricity = NYISO NYC Zone J. *Total % Capacity Reduction calculation: retired capacity / (retired capacity + 2016 operational capacity)





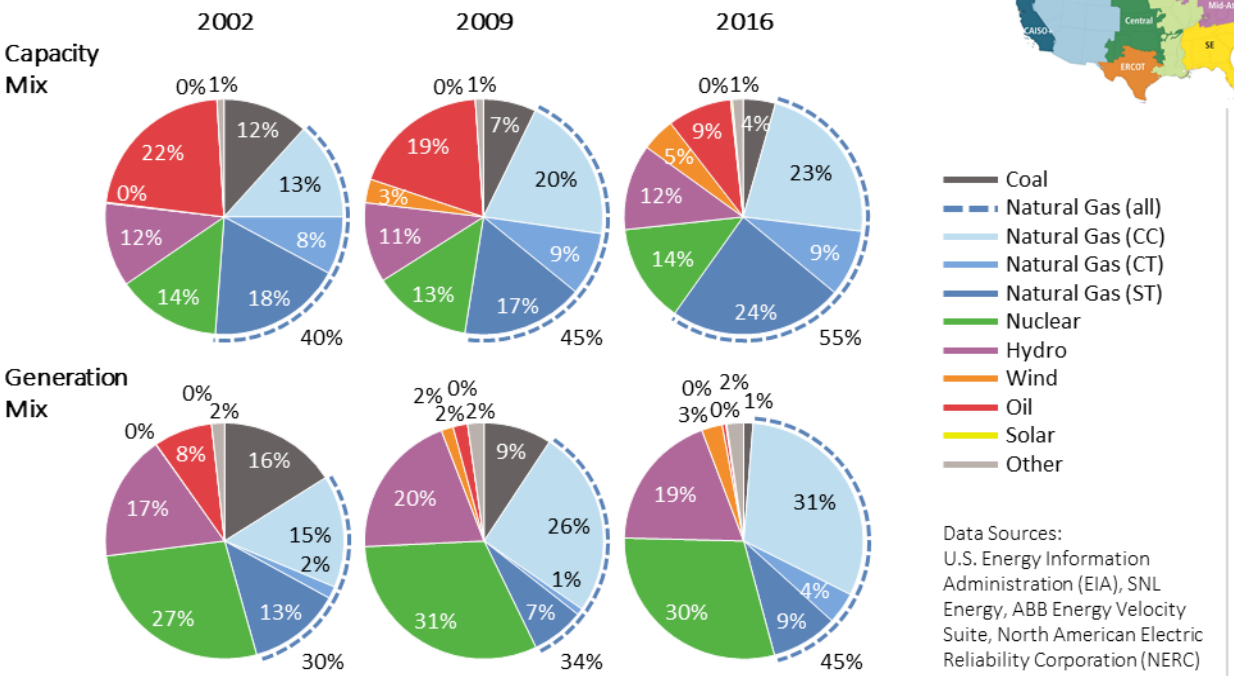


Total Capacity & Generation	2002	2016
Capacity (MW)	35,642	39,975
Generation (GWh)	145,126	140,728

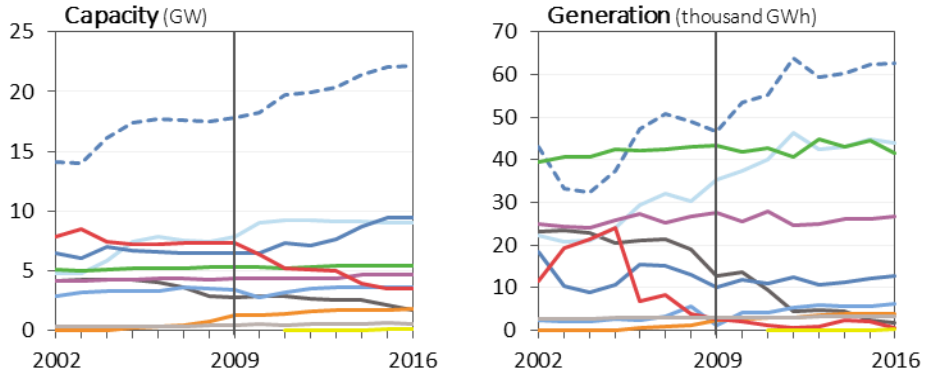
Retirements by Energy Source, 2002-2016	# of Generators	MW
Coal	26	2,129
Natural Gas	37	1,202
Nuclear	0	0
Oil	17	1,139
Hydro	13	15
Other (all other sources)	24	45
*Total % Cap. Reduction**	*10.2%*	**4,529**

NERC Reserve Margin, 2017 (2016 LTRA)	Target	Actual
NPCC-New York	15.00%	23.35%

New York Regional Profile



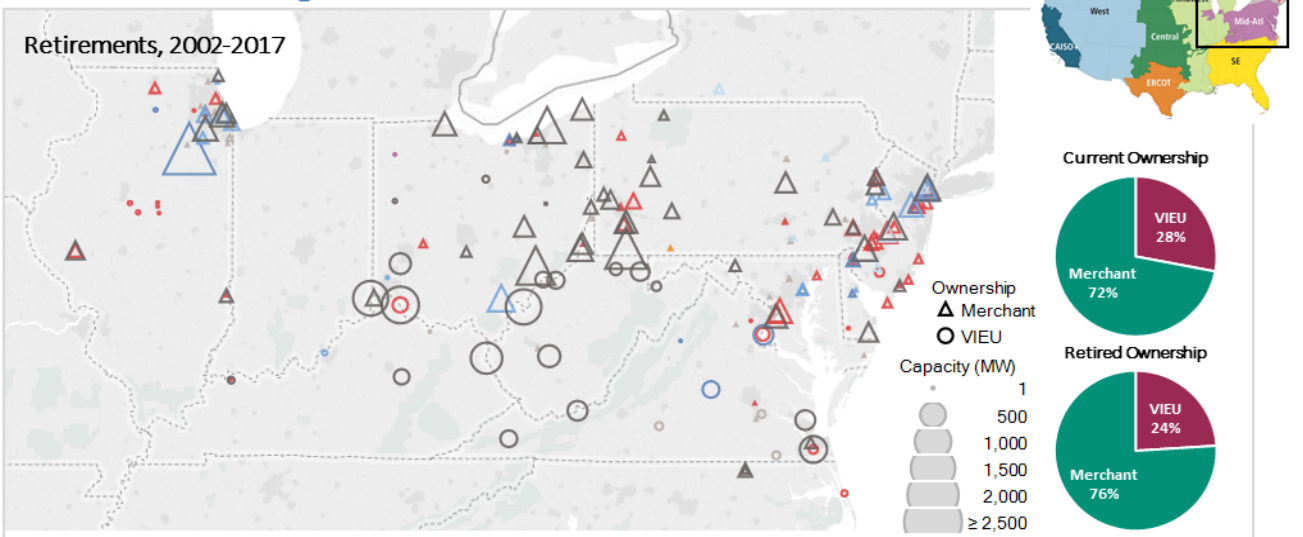
Data Sources:
U.S. Energy Information Administration (EIA), SNL Energy, ABB Energy Velocity Suite, North American Electric Reliability Corporation (NERC)

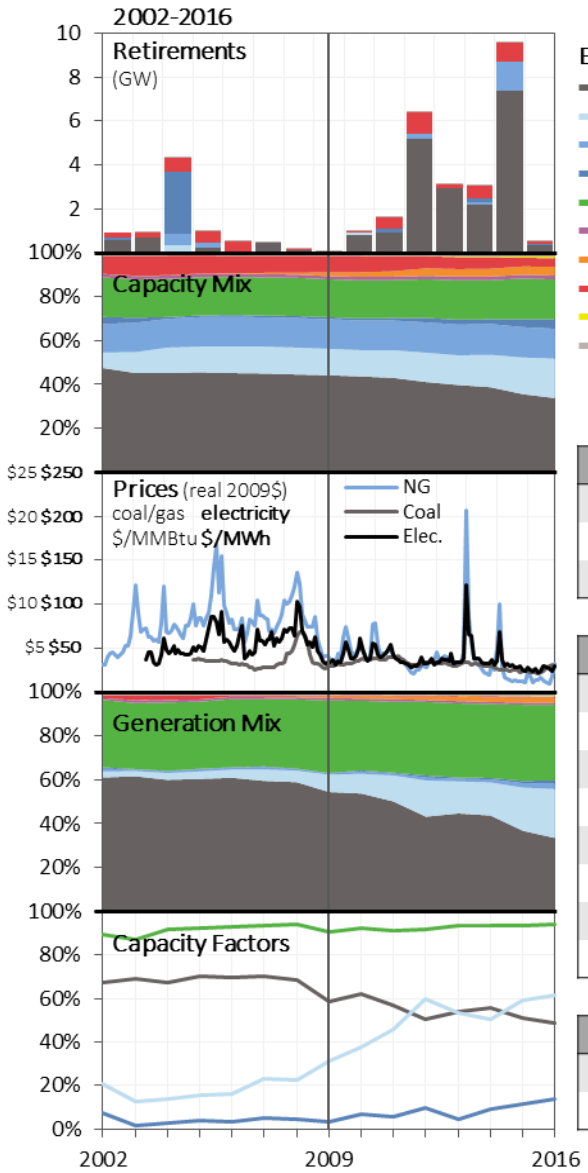


Capacity & Generation by Energy Source, 2002 & 2016

Energy Source	Capacity				Generation			
	2002 GW	%	2016 GW	%	2002 thous. GWh	%	2016 thous. GWh	%
Coal	4.1	*12%*	1.7	*4%*	23.2	*16%*	1.8	*1%*
Natural Gas	14.1	*40%*	22.1	*55%*	43.0	*30%*	62.8	*45%*
Combined Cycle (CC)	4.8	*13%*	9.0	*23%*	22.3	*15%*	43.9	*31%*
Combustion Turbine (CT)	2.8	*8%*	3.7	*9%*	2.4	*2%*	6.1	*4%*
Steam Turbine (ST)	6.5	*18%*	9.5	*24%*	18.3	*13%*	12.7	*9%*
Nuclear	5.0	*14%*	5.4	*14%*	39.6	*27%*	41.6	*30%*
Hydro	4.1	*12%*	4.7	*12%*	25.0	*17%*	26.6	*19%*
Wind	0.0	*0%*	1.8	*5%*	0.1	*0%*	3.9	*3%*
Oil	7.9	*22%*	3.5	*9%*	11.6	*8%*	0.7	*0%*
Solar	0.0	*0%*	0.1	*0%*	0.0	*0%*	0.2	*0%*
Other	0.3	*1%*	0.6	*1%*	2.5	*2%*	3.2	*2%*
Total	**35.6**	*100%*	**40.0**	*100%*	**145.1**	*100%*	**140.7**	*100%*

Mid-Atlantic Regional Profile





Energy Sources

- Coal
- Natural Gas (CC)
- Natural Gas (CT)
- Natural Gas (ST)
- Nuclear
- Hydro
- Wind
- Oil
- Solar
- Other

Notes:
Capacity values are summer capacity. Data for utility-scale resources only (1+ MW nameplate capacity). Natural gas technologies: CC = combined cycle, CT = combustion turbine, ST = steam turbine. Ownership type: VIEU = vertically integrated electric utility. Map includes 2017 Q1 actual and Q2-4 announced retirements. Prices: Natural gas = TETCO M3, Coal = Central App., Electricity = PJM Western Hub.
*Total % Capacity Reduction calculation: retired capacity / (retired capacity + 2016 operational capacity)

Total Capacity & Generation

	2002	2016
Capacity (MW)	180,697	186,759
Generation (GWh)	833,011	810,922

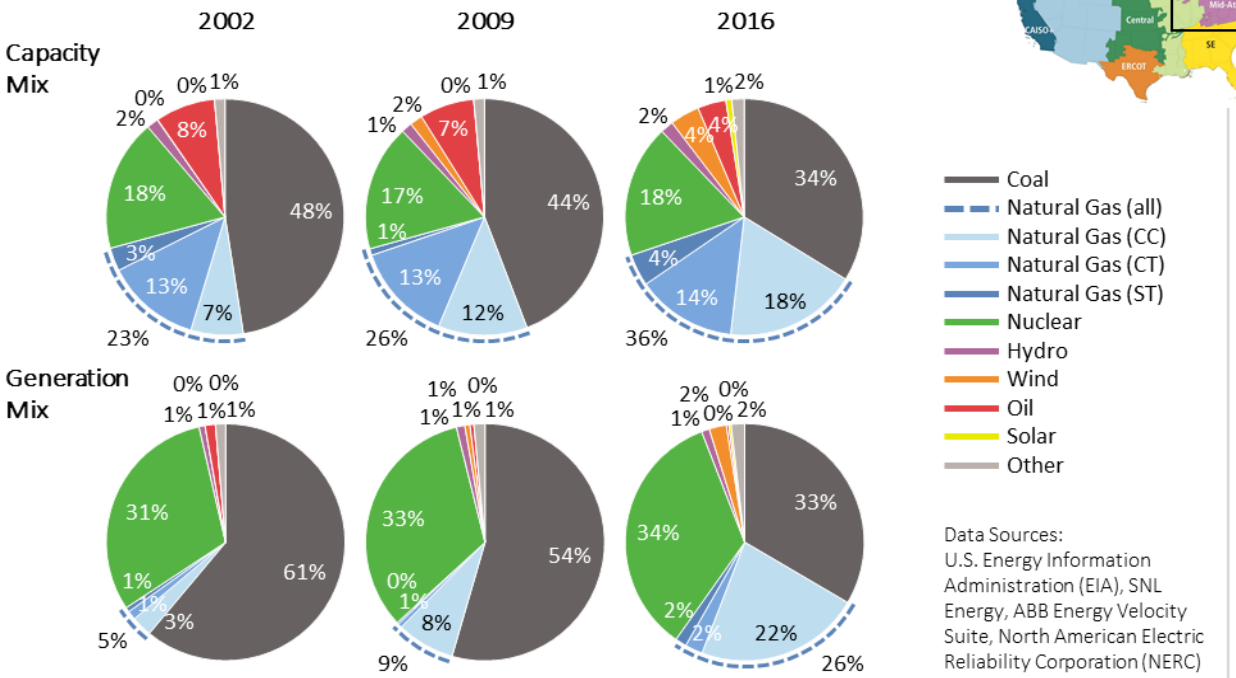
Retirements by Energy Source, 2002-2016

	# of Generators	MW
Coal	163	21,791
Natural Gas	152	6,315
Nuclear	0	0
Oil	173	5,326
Hydro	3	2
Other (all other sources)	95	224
*Total % Cap. Reduction**	*15.3%*	33,657

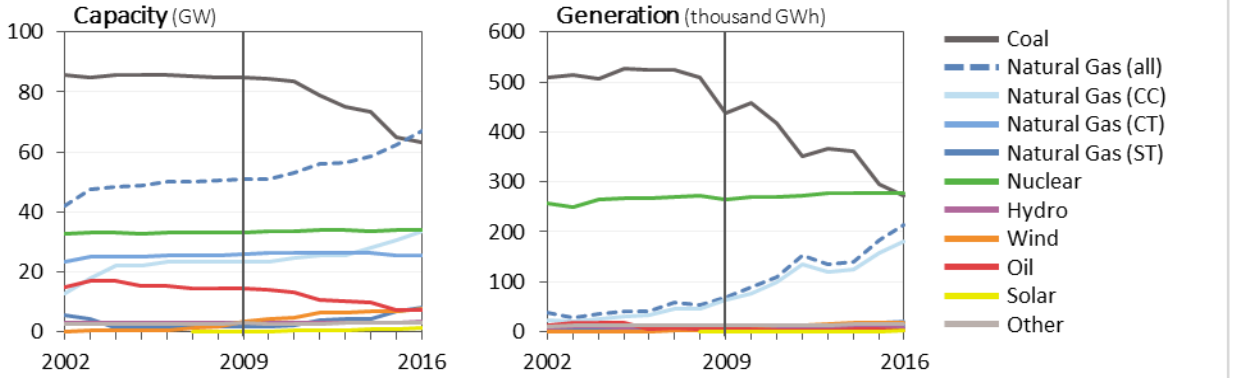
NERC Reserve Margin, 2017 (2016 LTRA)

	Target	Actual
PJM	16.50%	31.11%

Mid-Atlantic Regional Profile



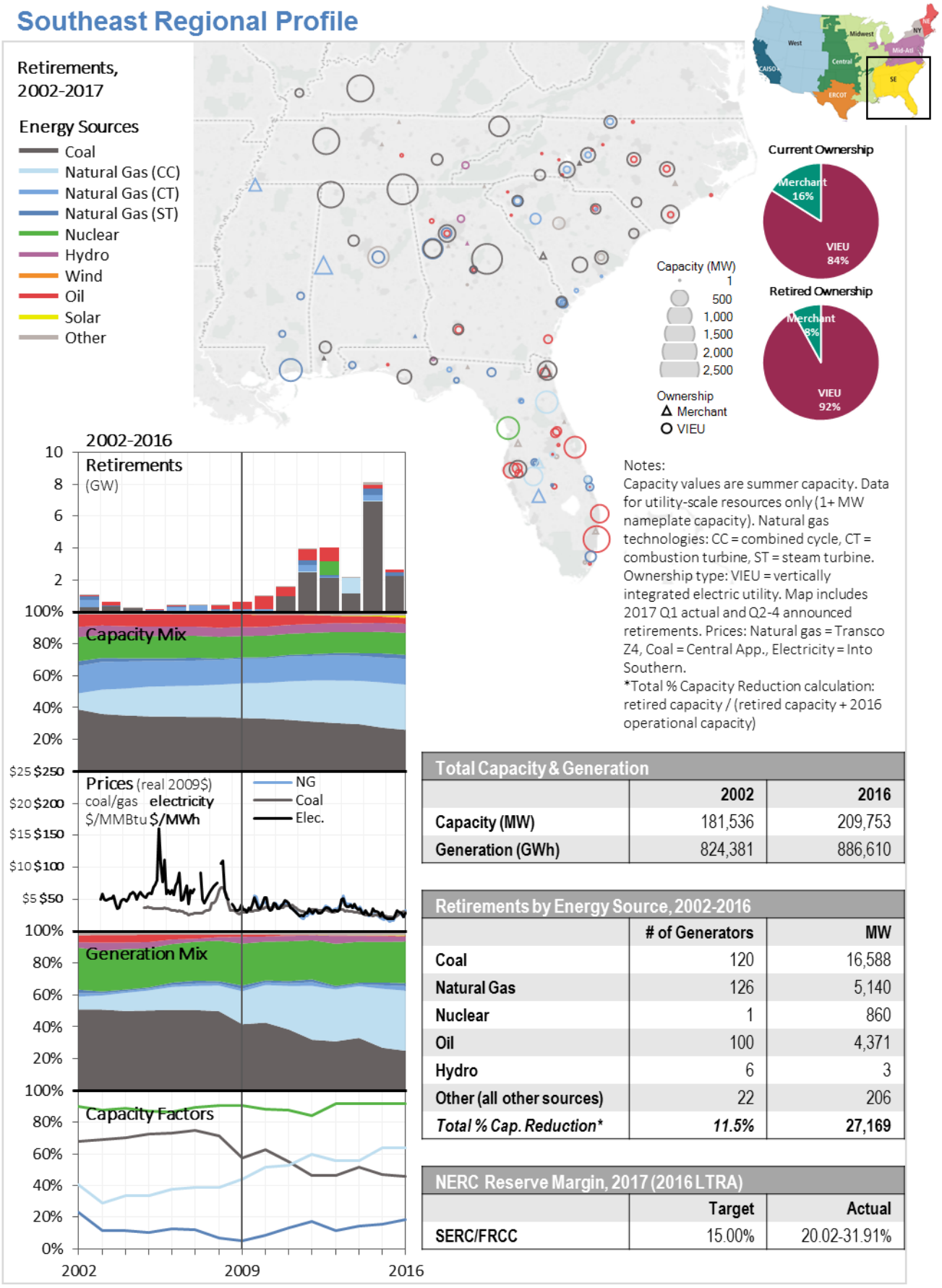
Data Sources:
U.S. Energy Information Administration (EIA), SNL Energy, ABB Energy Velocity Suite, North American Electric Reliability Corporation (NERC)



Capacity & Generation by Energy Source, 2002 & 2016

Energy Source	Capacity 2002 GW	%	Capacity 2016 GW	%	Generation 2002 thous. GWh	%	Generation 2016 thous. GWh	%
Coal	85.9	*48%*	63.1	*34%*	508.5	*61%*	271.6	*33%*
Natural Gas	41.9	*23%*	67.2	*36%*	38.7	*5%*	212.9	*26%*
Combined Cycle (CC)	12.8	*7%*	33.6	*18%*	23.3	*3%*	181.1	*22%*
Combustion Turbine (CT)	23.3	*13%*	25.4	*14%*	10.1	*1%*	19.4	*2%*
Steam Turbine (ST)	5.7	*3%*	8.1	*4%*	5.3	*1%*	12.4	*2%*
Nuclear	32.6	*18%*	33.8	*18%*	255.9	*31%*	278.8	*34%*
Hydro	2.9	*2%*	3.3	*2%*	6.8	*1%*	8.7	*1%*
Wind	0.1	*0%*	7.5	*4%*	0.1	*0%*	18.9	*2%*
Oil	14.8	*8%*	7.2	*4%*	11.7	*1%*	2.7	*0%*
Solar	0.0	*0%*	1.5	*1%*	0.0	*0%*	2.5	*0%*
Other	2.6	*1%*	3.1	*2%*	11.3	*1%*	14.7	*2%*
Total	**180.7**	*100%*	**186.8**	*100%*	**833.0**	*100%*	**810.9**	*100%*

Southeast Regional Profile



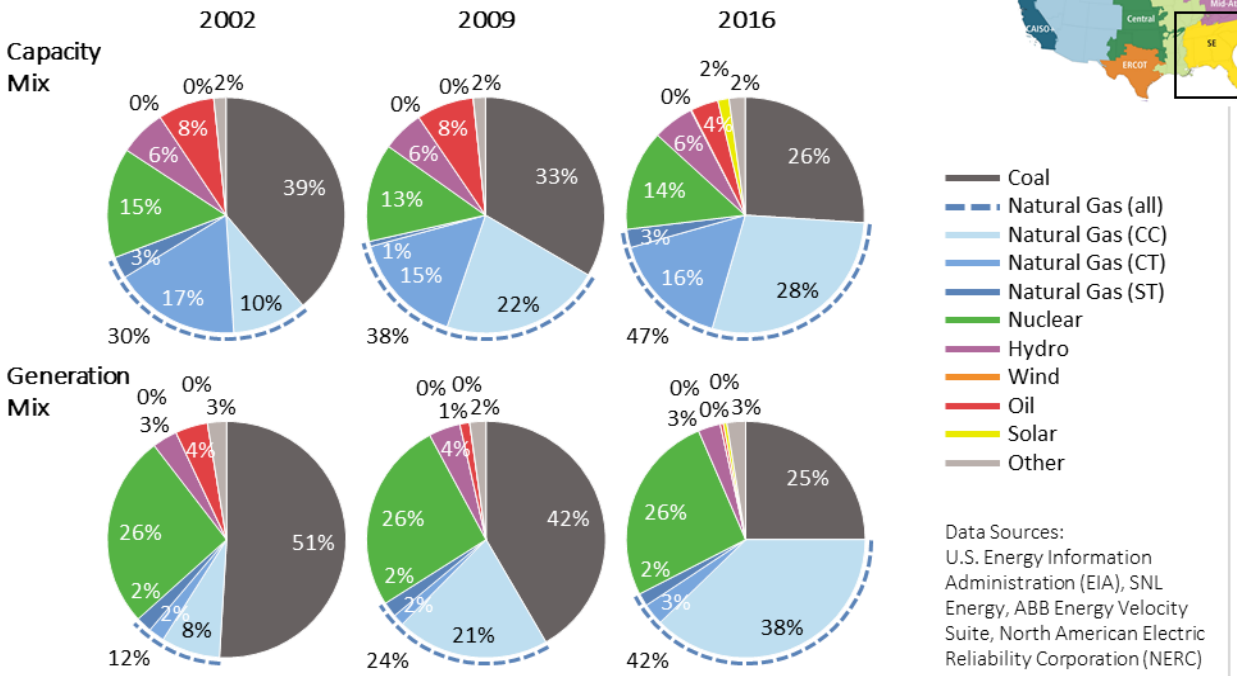
Notes:
Capacity values are summer capacity. Data for utility-scale resources only (1+ MW nameplate capacity). Natural gas technologies: CC = combined cycle, CT = combustion turbine, ST = steam turbine. Ownership type: VIEU = vertically integrated electric utility. Map includes 2017 Q1 actual and Q2-4 announced retirements. Prices: Natural gas = Transco Z4, Coal = Central App., Electricity = Into Southern.
*Total % Capacity Reduction calculation: retired capacity / (retired capacity + 2016 operational capacity)

Total Capacity & Generation	2002	2016
Capacity (MW)	181,536	209,753
Generation (GWh)	824,381	886,610

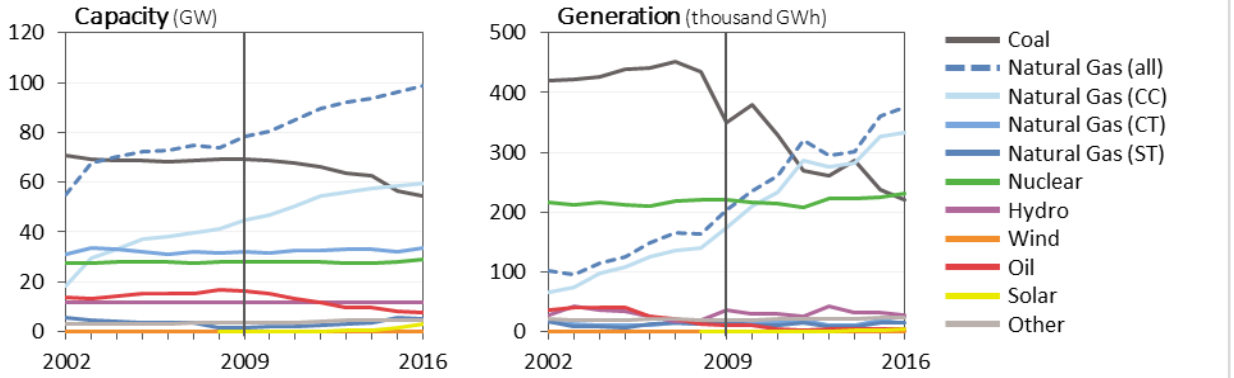
Retirements by Energy Source, 2002-2016	# of Generators	MW
Coal	120	16,588
Natural Gas	126	5,140
Nuclear	1	860
Oil	100	4,371
Hydro	6	3
Other (all other sources)	22	206
*Total % Cap. Reduction**	***11.5%***	**27,169**

NERC Reserve Margin, 2017 (2016 LTRA)	Target	Actual
SERC/FRCC	15.00%	20.02-31.91%

Southeast Regional Profile



Data Sources:
U.S. Energy Information Administration (EIA), SNL Energy, ABB Energy Velocity Suite, North American Electric Reliability Corporation (NERC)



Capacity & Generation by Energy Source, 2002 & 2016

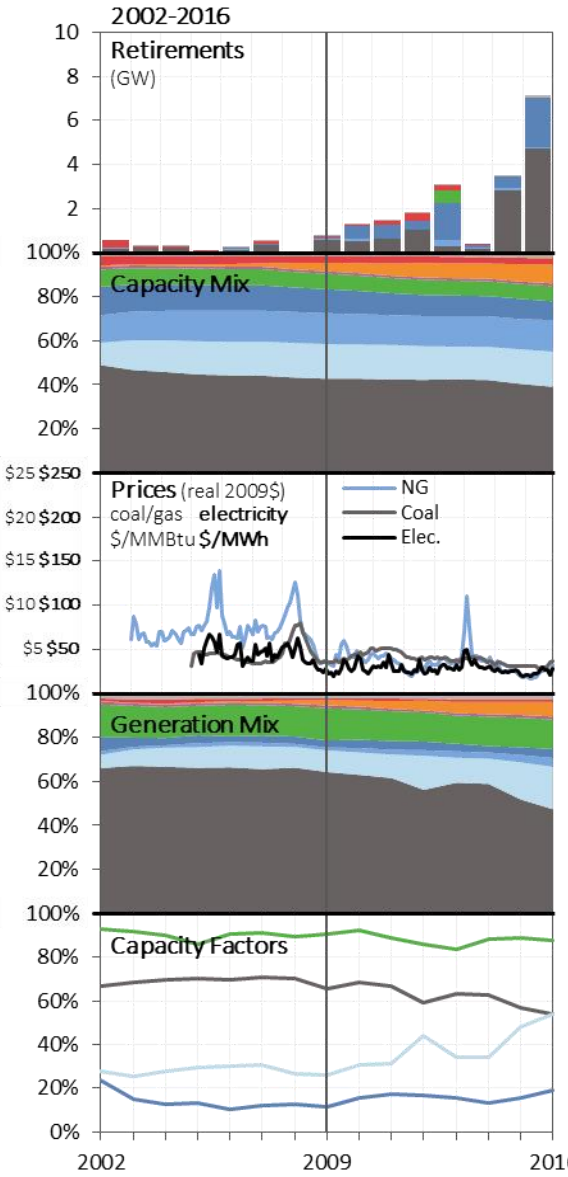
Energy Source	Capacity				Generation			
	2002 GW	%	2016 GW	%	2002 thous. GWh	%	2016 thous. GWh	%
Coal	70.5	*39%*	54.6	*26%*	420.1	*51%*	221.7	*25%*
Natural Gas	55.0	*30%*	98.7	*47%*	101.6	*12%*	375.8	*42%*
Combined Cycle (CC)	18.4	*10%*	59.6	*28%*	65.9	*8%*	334.0	*38%*
Combustion Turbine (CT)	31.2	*17%*	33.8	*16%*	18.0	*2%*	26.2	*3%*
Steam Turbine (ST)	5.4	*3%*	5.3	*3%*	17.8	*2%*	15.6	*2%*
Nuclear	27.5	*15%*	28.9	*14%*	217.2	*26%*	231.9	*26%*
Hydro	11.6	*6%*	11.7	*6%*	28.0	*3%*	26.9	*3%*
Wind	0.0	*0%*	0.2	*0%*	0.0	*0%*	0.0	*0%*
Oil	14.0	*8%*	7.9	*4%*	36.3	*4%*	3.6	*0%*
Solar	0.0	*0%*	3.2	*2%*	0.0	*0%*	4.3	*0%*
Other	3.0	*2%*	4.6	*2%*	21.2	*3%*	22.4	*3%*
Total	**181.5**	*100%*	**209.8**	*100%*	**824.4**	*100%*	**886.6**	*100%*

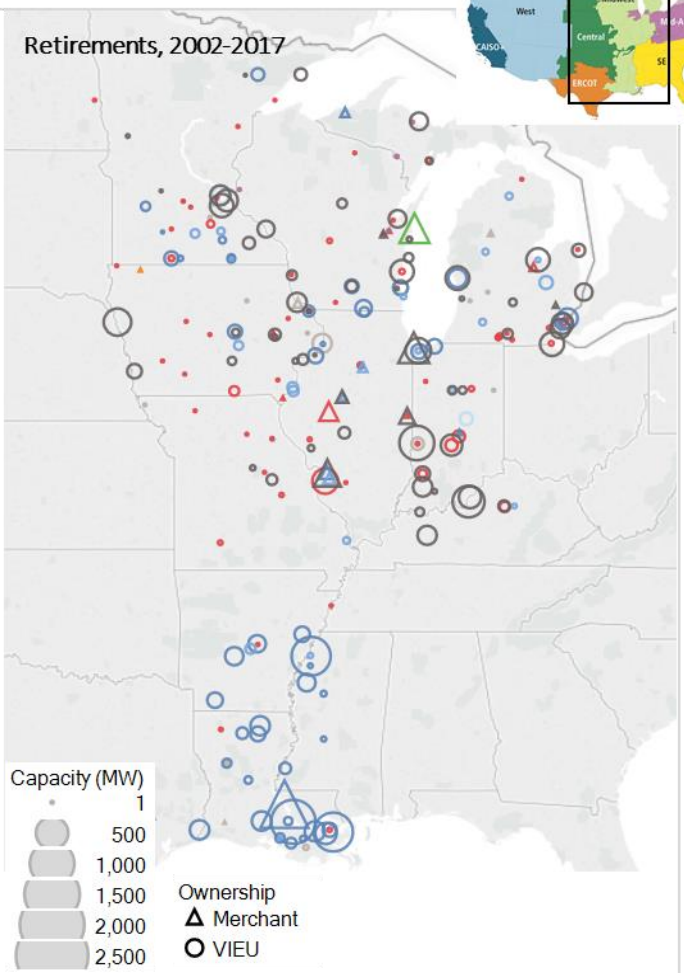
Midwest Regional Profile

Energy Sources

- Coal
- Natural Gas (CC)
- Natural Gas (CT)
- Natural Gas (ST)
- Nuclear
- Hydro
- Wind
- Oil
- Solar
- Other

Notes:
Capacity values are summer capacity. Data for utility-scale resources only (1+ MW nameplate capacity).
Natural gas technologies: CC = combined cycle, CT = combustion turbine, ST = steam turbine. Ownership type: VIEU = vertically integrated electric utility. Map includes 2017 Q1 actual and Q2-4 announced retirements.
Prices: Natural gas = Chicago, Coal = Powder River Basin, Electricity = MISO Illinois Hub.
*Total % Capacity Reduction calculation: retired capacity / (retired capacity + 2016 operational capacity)



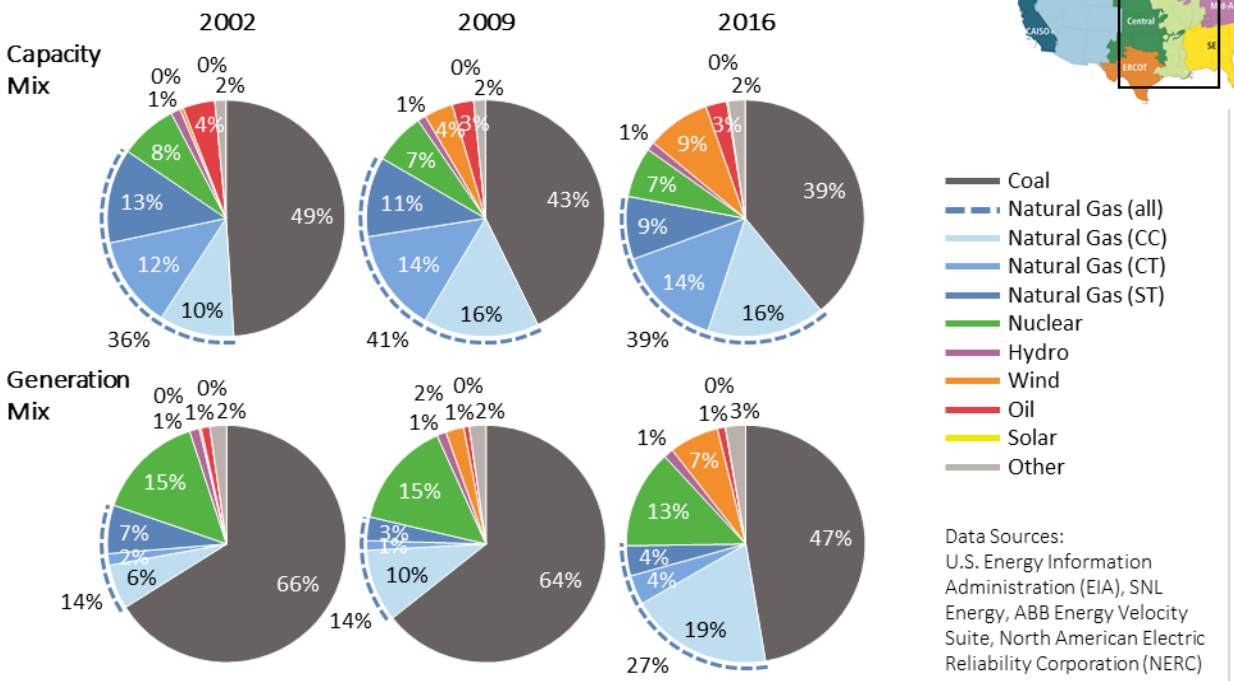


Total Capacity & Generation	2002	2016
Capacity (MW)	163,917	187,957
Generation (GWh)	710,131	744,323

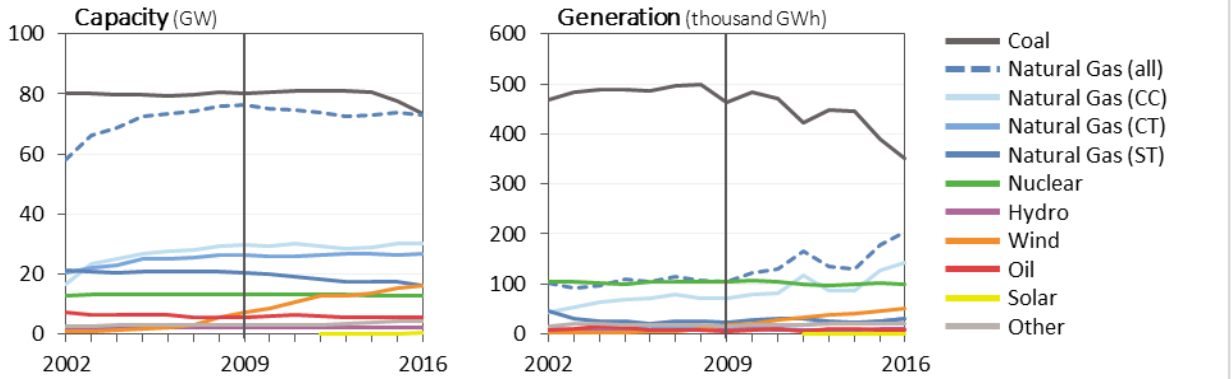
Retirements by Energy Source, 2002-2016	# of Generators	MW
Coal	151	11,815
Natural Gas	178	7,277
Nuclear	1	566
Oil	323	1,412
Hydro	17	15
Other (all other sources)	56	213
*Total % Cap. Reduction**	*10.2%*	21,297

NERC Reserve Margin, 2017 (2016 LTRA)	Target	Actual
MISO	15.20%	18.09%

Midwest Regional Profile



Data Sources:
U.S. Energy Information Administration (EIA), SNL Energy, ABB Energy Velocity Suite, North American Electric Reliability Corporation (NERC)



Capacity & Generation by Energy Source, 2002 & 2016

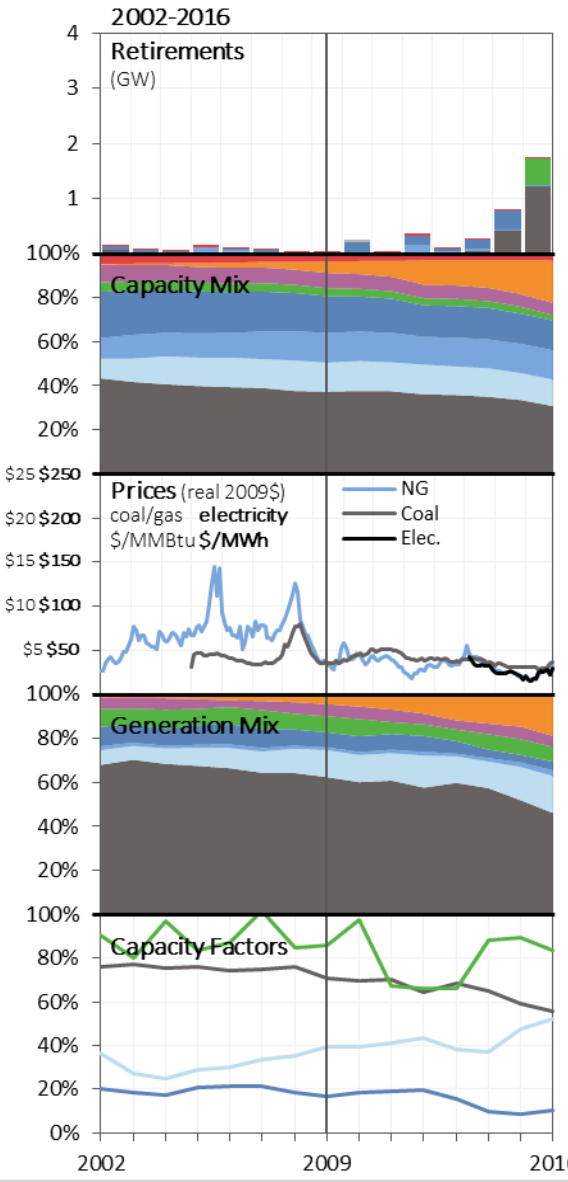
Energy Source	Capacity				Generation			
	2002 GW	%	2016 GW	%	2002 thous. GWh	%	2016 thous. GWh	%
Coal	80.3	*49%*	73.5	*39%*	469.0	*66%*	352.5	*47%*
Natural Gas	58.3	*36%*	73.1	*39%*	101.2	*14%*	204.0	*27%*
Combined Cycle (CC)	16.7	*10%*	30.0	*16%*	43.0	*6%*	143.7	*19%*
Combustion Turbine (CT)	20.5	*12%*	26.9	*14%*	11.3	*2%*	29.8	*4%*
Steam Turbine (ST)	21.2	*13%*	16.1	*9%*	46.9	*7%*	30.5	*4%*
Nuclear	12.8	*8%*	12.9	*7%*	104.3	*15%*	99.7	*13%*
Hydro	2.1	*1%*	2.2	*1%*	9.3	*1%*	9.9	*1%*
Wind	0.8	*0%*	16.3	*9%*	1.9	*0%*	49.8	*7%*
Oil	7.1	*4%*	5.4	*3%*	8.4	*1%*	7.9	*1%*
Solar	0.0	*0%*	0.3	*0%*	0.0	*0%*	0.3	*0%*
Other	2.5	*2%*	4.3	*2%*	16.0	*2%*	20.2	*3%*
Total	**163.9**	*100%*	**188.0**	*100%*	**710.1**	*100%*	**744.3**	*100%*

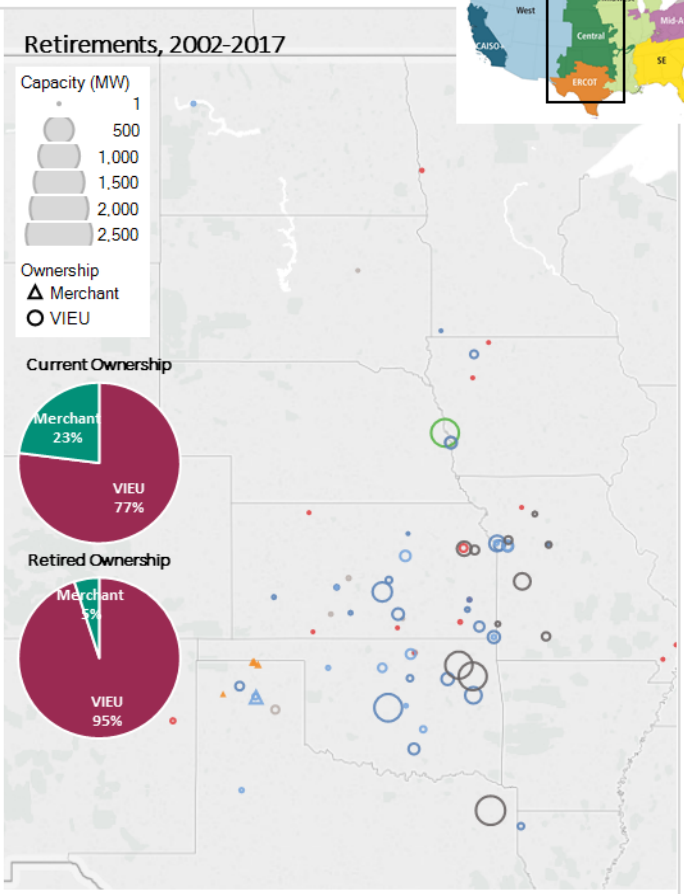
Central Regional Profile

Energy Sources

- Coal
- Natural Gas (CC)
- Natural Gas (CT)
- Natural Gas (ST)
- Nuclear
- Hydro
- Wind
- Oil
- Solar
- Other

Notes:
Capacity values are summer capacity. Data for utility-scale resources only (1+ MW nameplate capacity). Natural gas technologies: CC = combined cycle, CT = combustion turbine, ST = steam turbine. Ownership type: VIEU = vertically integrated electric utility. Map includes 2017 Q1 actual and Q2-4 announced retirements. Prices: Natural gas = Henry Hub, Coal = Powder River Basin, Electricity = SPP South Hub. *Total % Capacity Reduction calculation: retired capacity / (retired capacity + 2016 operational capacity)



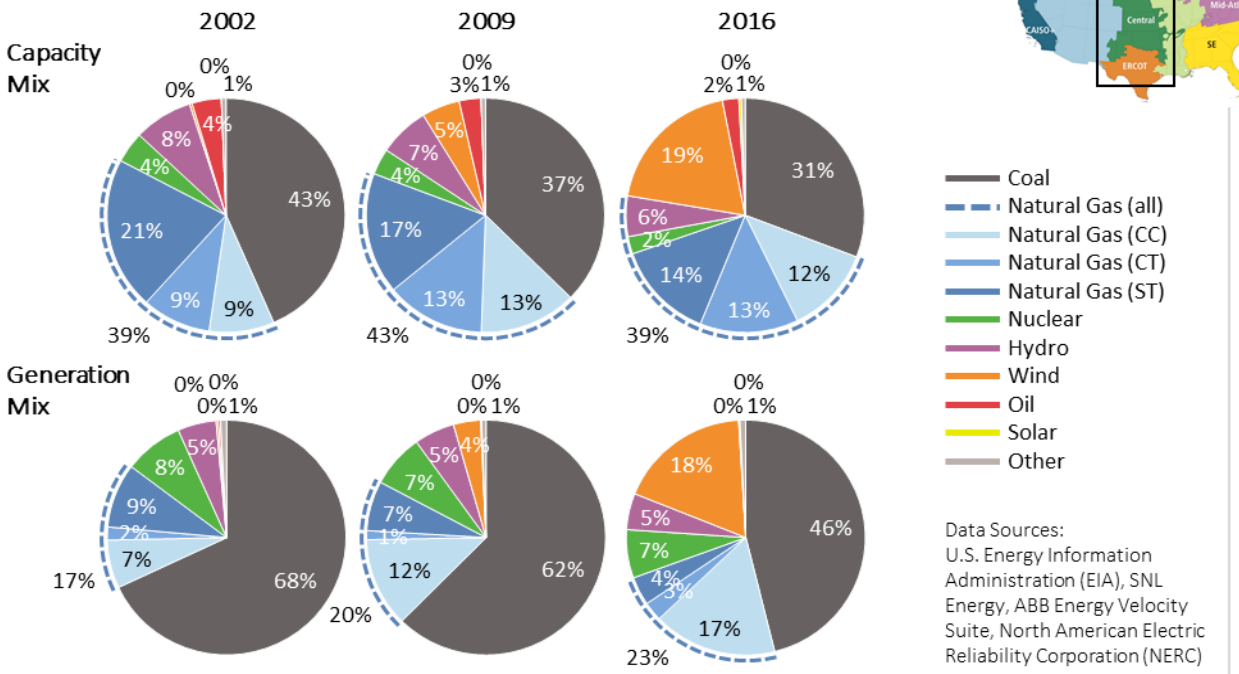


Total Capacity & Generation	2002	2016
Capacity (MW)	55,948	80,672
Generation (GWh)	237,790	264,354

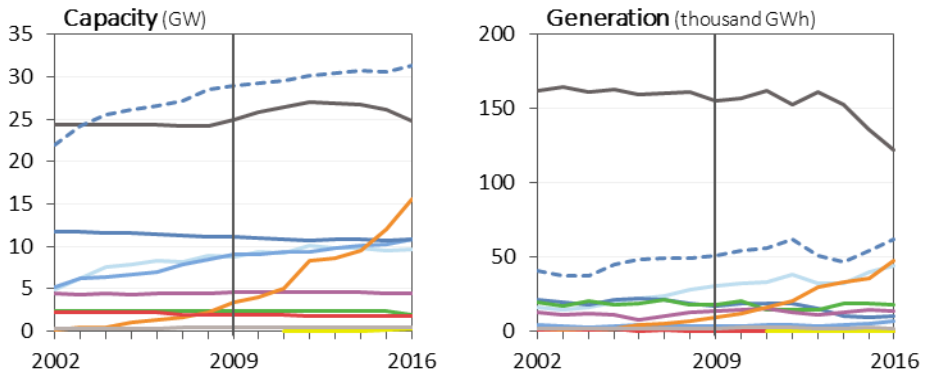
Retirements by Energy Source, 2002-2016	# of Generators	MW
Coal	22	1,749
Natural Gas	107	1,678
Nuclear	1	478
Oil	149	218
Hydro	0	0
Other (all other sources)	7	44
*Total % Cap. Reduction**	***4.9%***	**4,167**

NERC Reserve Margin, 2017 (2016 LTRA)	Target	Actual
SPP	12.00%	27.16%

Central Regional Profile



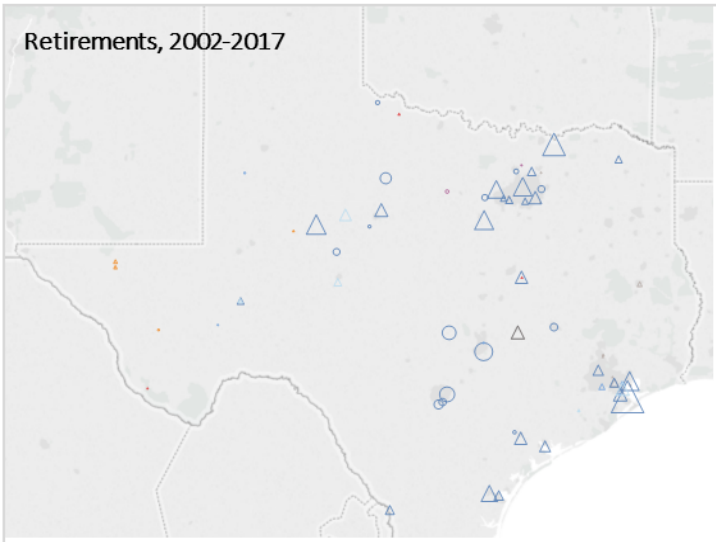
Data Sources:
U.S. Energy Information Administration (EIA), SNL Energy, ABB Energy Velocity Suite, North American Electric Reliability Corporation (NERC)



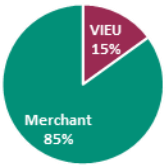
Capacity & Generation by Energy Source, 2002 & 2016

Energy Source	Capacity 2002 GW	%	Capacity 2016 GW	%	Generation 2002 thous. GWh	%	Generation 2016 thous. GWh	%
Coal	24.3	*43%*	24.8	*31%*	161.7	*68%*	121.9	*46%*
Natural Gas	22.0	*39%*	31.4	*39%*	41.1	*17%*	61.7	*23%*
Combined Cycle (CC)	4.9	*9%*	9.7	*12%*	15.8	*7%*	44.3	*17%*
Combustion Turbine (CT)	5.3	*9%*	10.8	*13%*	4.3	*2%*	6.9	*3%*
Steam Turbine (ST)	11.8	*21%*	10.9	*14%*	21.1	*9%*	10.4	*4%*
Nuclear	2.4	*4%*	1.9	*2%*	19.2	*8%*	17.6	*7%*
Hydro	4.5	*8%*	4.5	*6%*	12.4	*5%*	13.2	*5%*
Wind	0.2	*0%*	15.5	*19%*	0.7	*0%*	47.5	*18%*
Oil	2.2	*4%*	1.8	*2%*	0.7	*0%*	0.1	*0%*
Solar	0.0	*0%*	0.3	*0%*	0.0	*0%*	0.3	*0%*
Other	0.4	*1%*	0.4	*1%*	1.9	*1%*	2.1	*1%*
Total	**55.9**	*100%*	**80.7**	*100%*	**237.8**	*100%*	**264.4**	*100%*

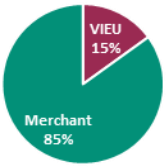
ERCOT Regional Profile

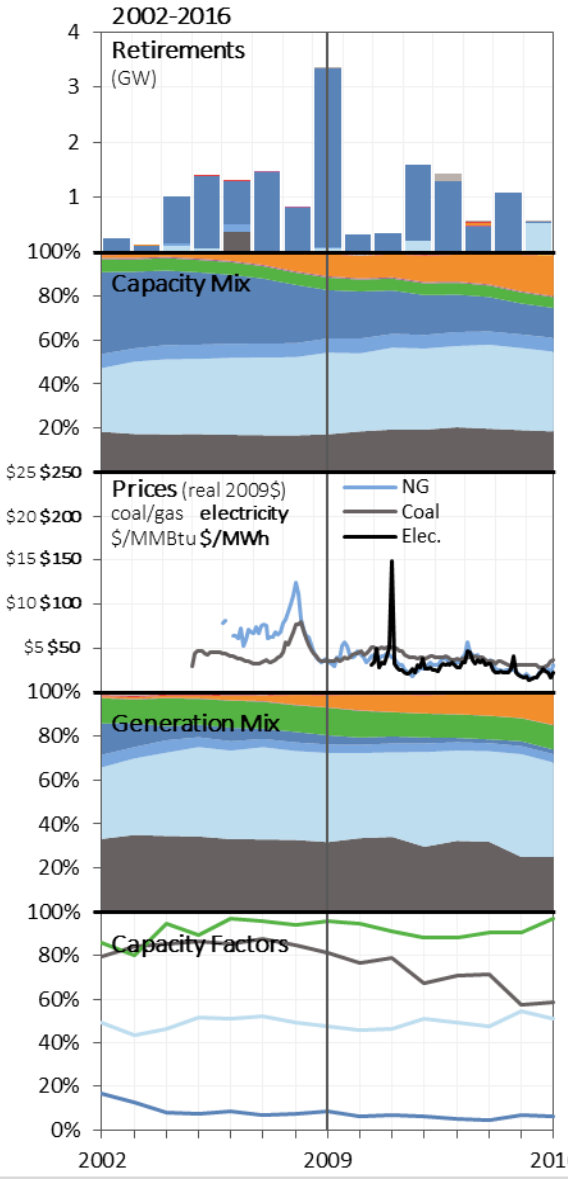


Current Ownership



Retired Ownership





Energy Sources

- Coal
- Natural Gas (CC)
- Natural Gas (CT)
- Natural Gas (ST)
- Nuclear
- Hydro
- Wind
- Oil
- Solar
- Other

Notes:
Capacity values are summer capacity. Data for utility-scale resources only (1+ MW nameplate capacity). Natural gas technologies: CC = combined cycle, CT = combustion turbine, ST = steam turbine. Ownership type: VIEU = vertically integrated electric utility. Map includes 2017 Q1 actual and Q2-4 announced retirements. Prices: Natural gas = Houston Ship Channel, Coal = Powder River Basin, Electricity = ERCOT North Hub.
*Total % Capacity Reduction calculation: retired capacity / (retired capacity + 2016 operational capacity)

Total Capacity & Generation

	2002	2016
Capacity (MW)	80,762	101,310
Generation (GWh)	312,059	382,003

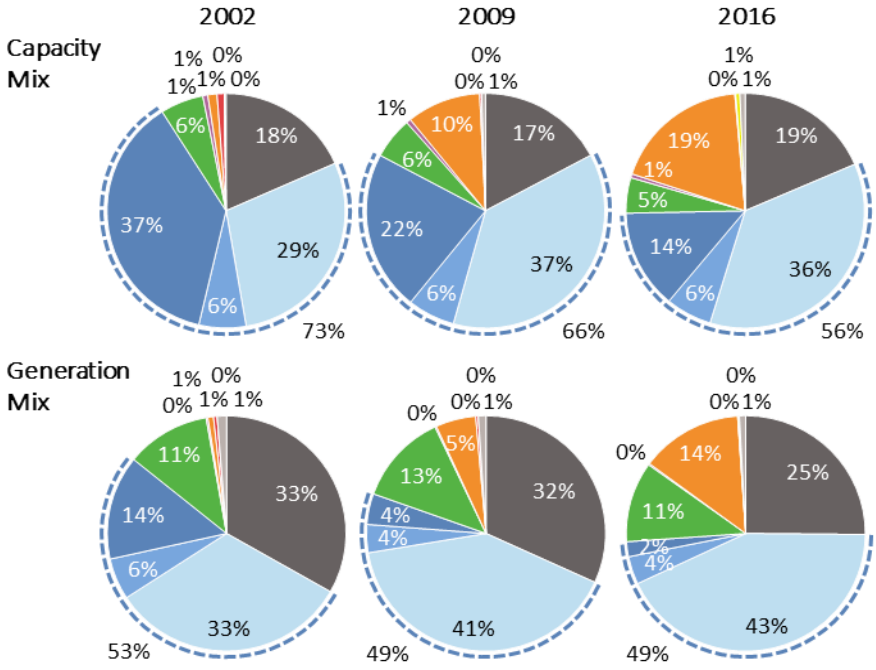
Retirements by Energy Source, 2002-2016

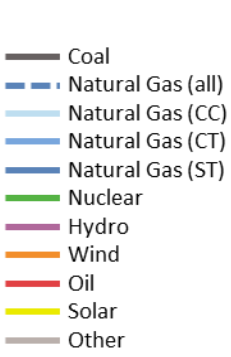
	# of Generators	MW
Coal	3	363
Natural Gas	155	14,894
Nuclear	0	0
Oil	10	17
Hydro	6	26
Other (all other sources)	23	234
*Total % Cap. Reduction**	*13.3%*	15,534

NERC Reserve Margin, 2017 (2016 LTRA)

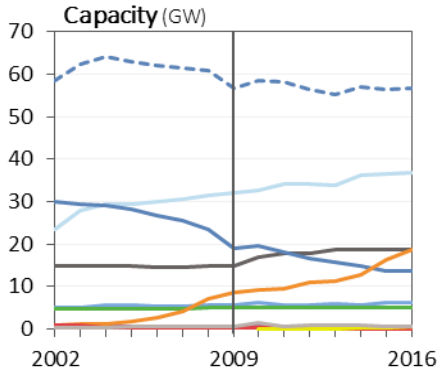
	Target	Actual
ERCOT	13.75%	17.45%

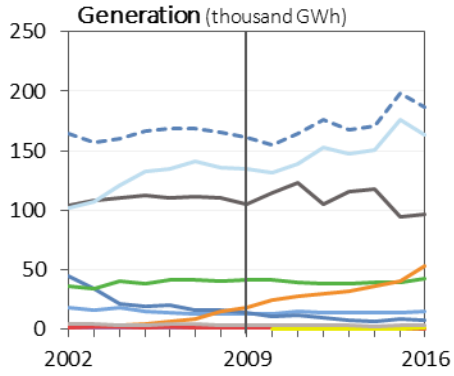
ERCOT Regional Profile

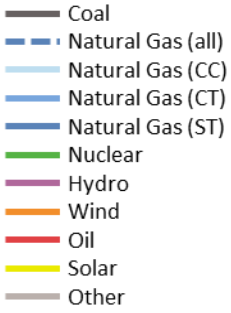




Data Sources:
U.S. Energy Information Administration (EIA), SNL Energy, ABB Energy Velocity Suite, North American Electric Reliability Corporation (NERC)







Capacity & Generation by Energy Source, 2002 & 2016

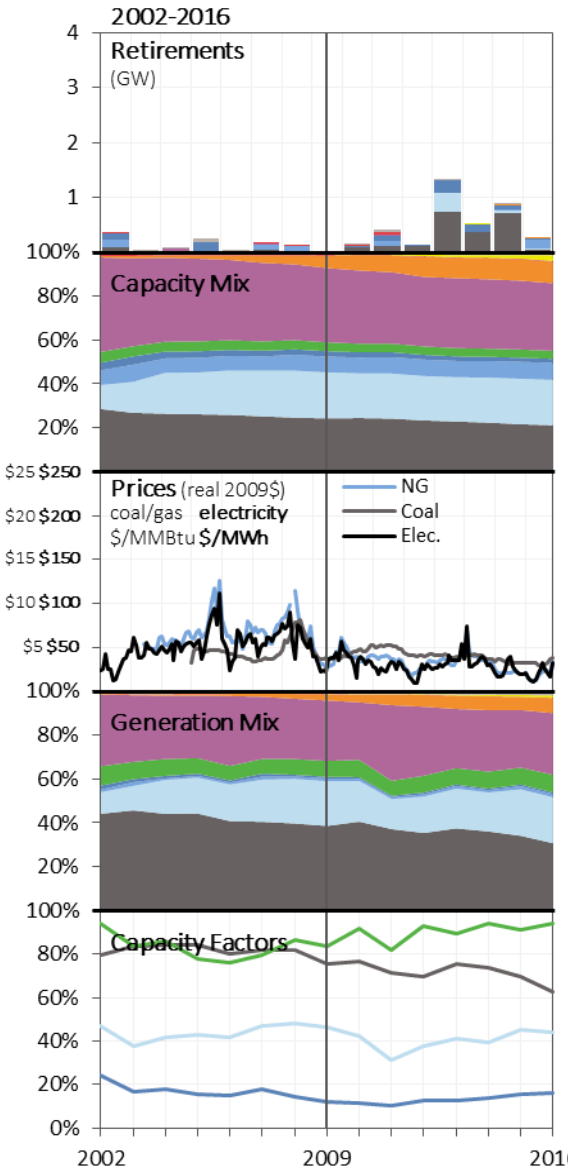
Energy Source	Capacity 2002 GW	%	Capacity 2016 GW	%	Generation 2002 thous. GWh	%	Generation 2016 thous. GWh	%
Coal	14.9	*18%*	18.8	*19%*	103.8	*33%*	96.1	*25%*
Natural Gas	58.6	*73%*	56.9	*56%*	164.1	*53%*	186.2	*49%*
Combined Cycle (CC)	23.3	*29%*	36.7	*36%*	101.6	*33%*	163.7	*43%*
Combustion Turbine (CT)	5.2	*6%*	6.4	*6%*	17.7	*6%*	14.6	*4%*
Steam Turbine (ST)	30.1	*37%*	13.8	*14%*	44.7	*14%*	7.9	*2%*
Nuclear	4.7	*6%*	5.0	*5%*	35.6	*11%*	42.1	*11%*
Hydro	0.6	*1%*	0.5	*1%*	0.7	*0%*	0.8	*0%*
Wind	1.0	*1%*	18.8	*19%*	2.4	*1%*	52.7	*14%*
Oil	0.8	*1%*	0.1	*0%*	1.6	*1%*	0.2	*0%*
Solar	0.0	*0%*	0.6	*1%*	0.0	*0%*	0.7	*0%*
Other	0.2	*0%*	0.7	*1%*	3.9	*1%*	3.2	*1%*
Total	**80.8**	*100%*	**101.3**	*100%*	**312.1**	*100%*	**382.0**	*100%*

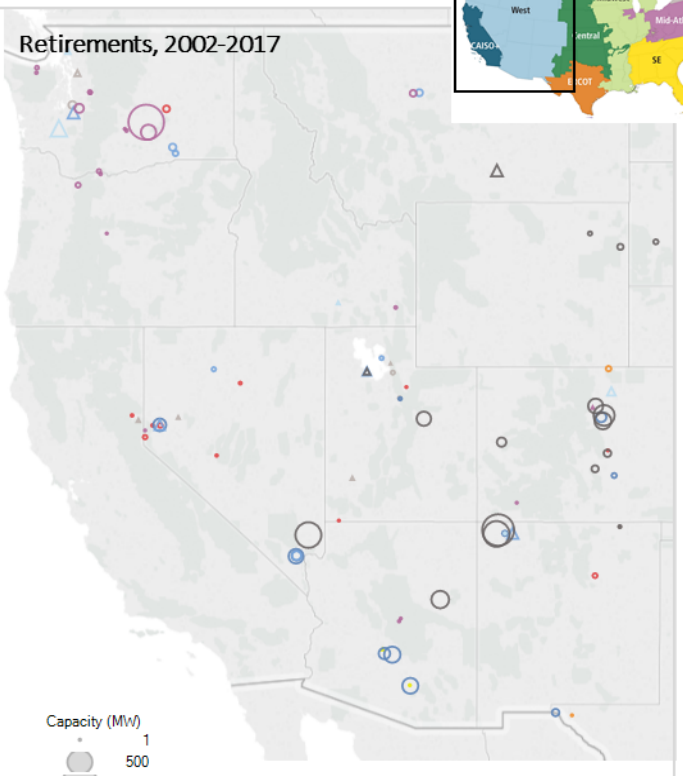
West Regional Profile

Energy Sources

- Coal
- Natural Gas (CC)
- Natural Gas (CT)
- Natural Gas (ST)
- Nuclear
- Hydro
- Wind
- Oil
- Solar
- Other

Notes:
Capacity values are summer capacity. Data for utility-scale resources only (1+ MW nameplate capacity).
Natural gas technologies: CC = combined cycle, CT = combustion turbine, ST = steam turbine. Ownership type: VIEU = vertically integrated electric utility. Map includes 2017 Q1 actual and Q2-4 announced retirements.
Prices: Natural gas = NW Sumas, Coal = Powder River Basin, Electricity = Mid-Columbia. *Total % Capacity Reduction calculation: retired capacity / (retired capacity + 2016 operational capacity)



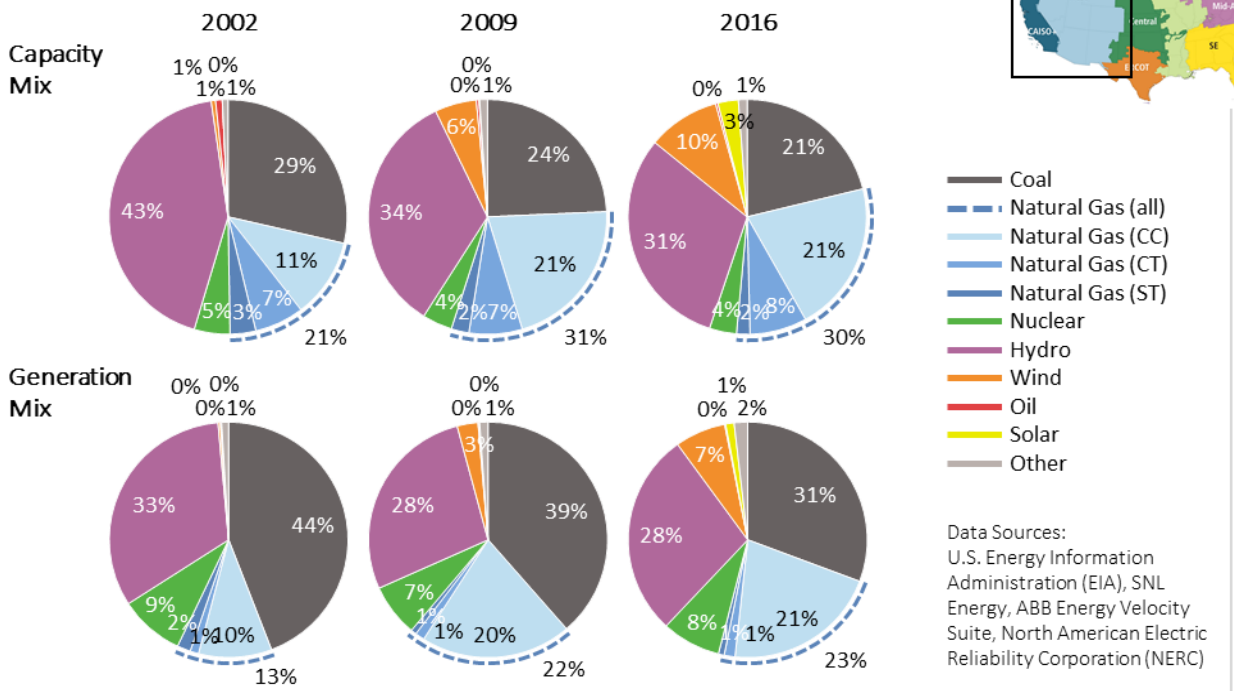


Total Capacity & Generation	2002	2016
Capacity (MW)	99,795	138,238
Generation (GWh)	452,765	524,861

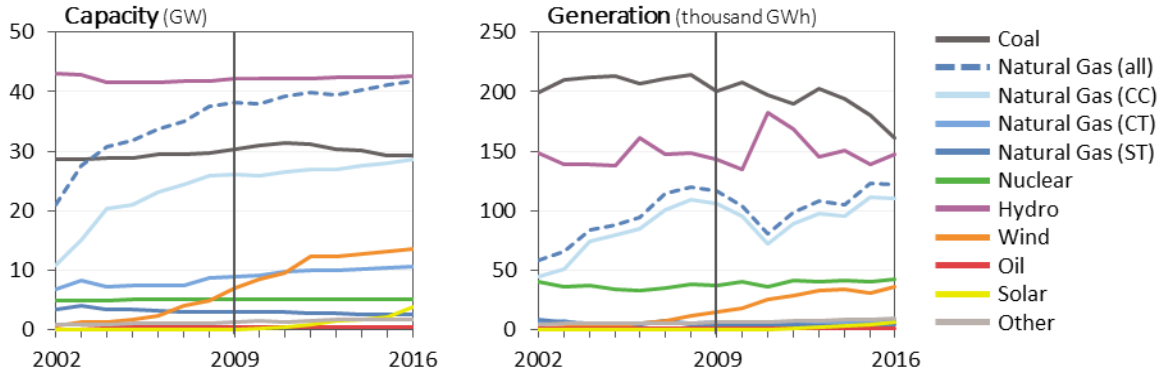
Retirements by Energy Source, 2002-2016	# of Generators	MW
Coal	29	2,292
Natural Gas	81	1,900
Nuclear	0	0
Oil	70	141
Hydro	38	171
Other (all other sources)	48	180
*Total % Cap. Reduction**	*3.3%*	4,683

NERC Reserve Margin, 2017 (2016 LTRA)	Target	Actual
WECC	15.90%	26.80%

West Regional Profile



Data Sources:
U.S. Energy Information Administration (EIA), SNL Energy, ABB Energy Velocity Suite, North American Electric Reliability Corporation (NERC)



Capacity & Generation by Energy Source, 2002 & 2016

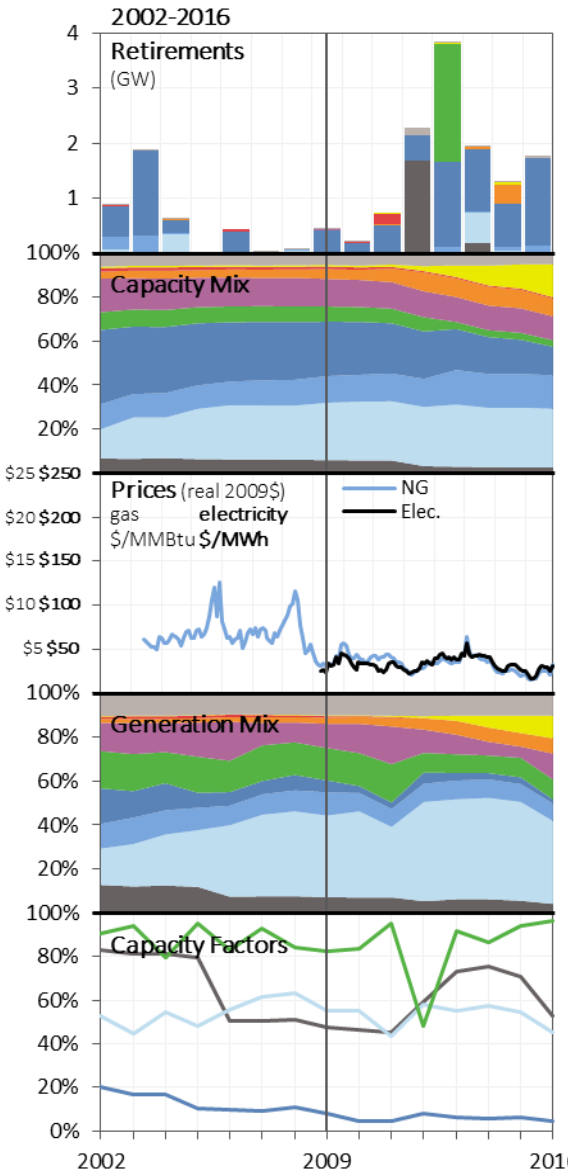
Energy Source	Capacity				Generation			
	2002 GW	%	2016 GW	%	2002 thous. GWh	%	2016 thous. GWh	%
Coal	28.6	*29%*	29.3	*21%*	199.9	*44%*	161.3	*31%*
Natural Gas	21.1	*21%*	41.8	*30%*	58.4	*13%*	121.8	*23%*
Combined Cycle (CC)	10.9	*11%*	28.6	*21%*	44.9	*10%*	110.0	*21%*
Combustion Turbine (CT)	6.7	*7%*	10.7	*8%*	5.2	*1%*	7.7	*1%*
Steam Turbine (ST)	3.5	*3%*	2.5	*2%*	8.3	*2%*	4.1	*1%*
Nuclear	4.8	*5%*	5.1	*4%*	39.9	*9%*	42.0	*8%*
Hydro	43.0	*43%*	42.6	*31%*	148.1	*33%*	147.3	*28%*
Wind	0.6	*1%*	13.6	*10%*	1.4	*0%*	36.1	*7%*
Oil	0.9	*1%*	0.4	*0%*	0.8	*0%*	0.7	*0%*
Solar	0.0	*0%*	3.8	*3%*	0.0	*0%*	6.0	*1%*
Other	0.8	*1%*	1.6	*1%*	4.3	*1%*	9.6	*2%*
Total	**99.8**	*100%*	**138.2**	*100%*	**452.8**	*100%*	**524.9**	*100%*

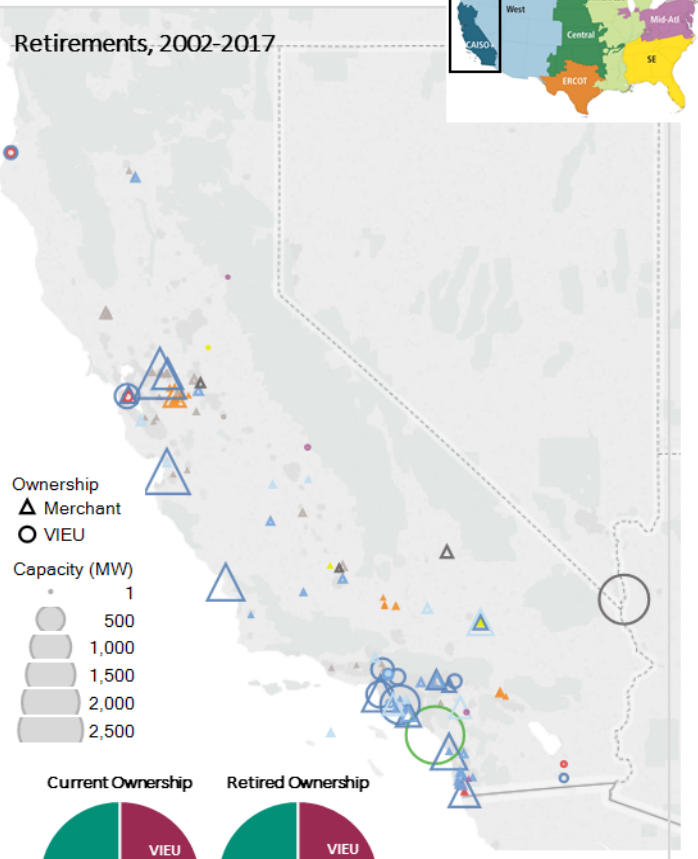
CAISO+ Regional Profile

Energy Sources

- Coal
- Natural Gas (CC)
- Natural Gas (CT)
- Natural Gas (ST)
- Nuclear
- Hydro
- Wind
- Oil
- Solar
- Other

Notes:
Capacity values are summer capacity. Data for utility-scale resources only (1+ MW nameplate capacity). Natural gas technologies: CC = combined cycle, CT = combustion turbine, ST = steam turbine. Ownership type: VIEU = vertically integrated electric utility. Map includes 2017 Q1 actual and Q2-4 announced retirements. Prices: Natural gas = SoCal Border, Electricity = CAISO SP15. *Total % Capacity Reduction calculation: retired capacity / (retired capacity + 2016 operational capacity)



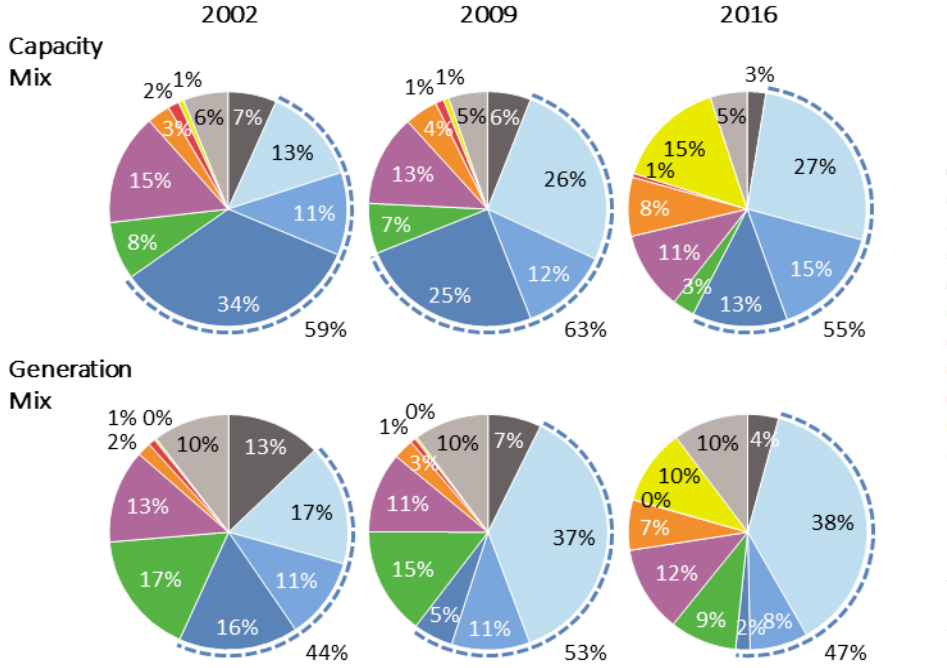


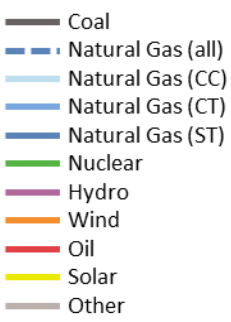
Total Capacity & Generation	2002	2016
Capacity (MW)	54,022	74,431
Generation (GWh)	203,028	208,137

Retirements by Energy Source, 2002-2016	# of Generators	MW
Coal	7	1,855
Natural Gas	111	11,272
Nuclear	2	2,150
Oil	12	315
Hydro	7	26
Other (all other sources)	146	832
Total % Cap. Reduction*	***18.1%***	**16,450**

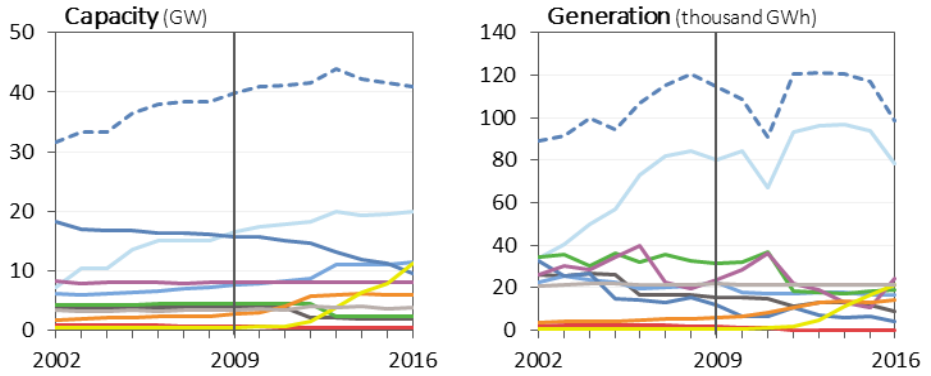
NERC Reserve Margin, 2017 (2016 LTRA)	Target	Actual
CAISO	19.50%	24.40%

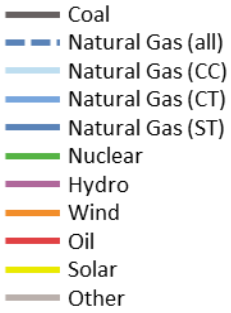
CAISO+ Regional Profile





Data Sources:
U.S. Energy Information Administration (EIA), SNL Energy, ABB Energy Velocity Suite, North American Electric Reliability Corporation (NERC)





Capacity & Generation by Energy Source, 2002 & 2016

Energy Source	Capacity 2002 GW	%	Capacity 2016 GW	%	Generation 2002 thous. GWh	%	Generation 2016 thous. GWh	%
Coal	3.6	*7%*	1.9	*3%*	26.0	*13%*	8.7	*4%*
Natural Gas	31.6	*59%*	40.9	*55%*	89.2	*44%*	98.8	*47%*
Combined Cycle (CC)	7.2	*13%*	19.9	*27%*	33.6	*17%*	78.3	*38%*
Combustion Turbine (CT)	6.2	*11%*	11.4	*15%*	22.7	*11%*	16.4	*8%*
Steam Turbine (ST)	18.3	*34%*	9.6	*13%*	32.9	*16%*	4.0	*2%*
Nuclear	4.3	*8%*	2.2	*3%*	34.4	*17%*	18.9	*9%*
Hydro	8.3	*15%*	8.0	*11%*	26.1	*13%*	24.6	*12%*
Wind	1.7	*3%*	6.0	*8%*	3.8	*2%*	14.4	*7%*
Oil	0.8	*2%*	0.4	*1%*	2.0	*1%*	0.1	*0%*
Solar	0.4	*1%*	11.2	*15%*	0.6	*0%*	21.5	*10%*
Other	3.3	*6%*	3.7	*5%*	21.0	*10%*	21.2	*10%*
Total	**54.0**	*100%*	**74.4**	*100%*	**203.0**	*100%*	**208.1**	*100%*

Appendix B: VRE Integration Studies

Numerous technical studies on electricity systems in most regions of the Nation have concluded that significantly higher levels of VRE can be successfully integrated without compromising resource adequacy.[hhhh] Demonstrating resource adequacy is essential, but achieving the modeled levels of VRE penetration requires a full consideration of "all-in" costs, land use, siting, and other environmental impacts; sustainable economics for non-wind and solar resources; for some studies, required changes at the distribution level; wholesale market design and organizational changes; spending on relevant transmission and distribution grid modernization activities; and ensuring all aspects of operational reliability.[iiii] These caveats are non-trivial, as they would be for any substantial major changes in the electric power system.

Table B-1. VRE Integration Studies [471]

Region	VRE Pen.	Author	Study Year	Study Title
United States	50%	NREL	2012	*Renewable Electricity Futures Study*
Western Interconnection	33%	NREL	2013	*Western Wind and Solar Integration Study: Phase 2*
	33%	GE Energy	2014	*Western Wind and Solar Integration Study Phase 3 – Frequency Response and Transient Stability*
	33%	GE Energy	2015	*Western Wind and Solar Integration Study Phase 3A: Low Levels of Synchronous Generation*
	35%	E3 and NREL	2015	*Western Interconnection Flexibility Assessment*
	52%	NREL	2015	*Renewable Electricity Futures: Operational Analysis of the Western Interconnection at Very High Renewable Penetrations*
CAISO	12%	CAISO	2010	*Integration of Renewable Resources at 20% RPS*
	50%[#]	GE Energy	2011	*California ISO Frequency Response Study*
	37%	E3	2014	*Investigating a Higher Renewables Portfolio Standard in California*

[hhhh] However, these studies (particularly those examining high VRE levels) may often assume (or ignore) modeled conditions that could be difficult and/or costly to achieve in practice, such as a large transmission buildout that may face siting or other obstacles, ability of non-wind and solar plants to remain financially viable and thus available, institutional changes, or, for one study, synchronization of all three interconnections.

[iiii] Operational reliability (which includes ensuring a set of ERS are maintained to help the electric system react to sudden stability disruptions or unanticipated losses of system components in real-time) is just as important as the resource adequacy aspect of BPS reliability. But modeling all needed aspects of operational reliability is very difficult computationally, and so not usually examined in its totality in these studies. For example, NREL in its Renewable Electricity Futures Study states, "The study did not conduct a full reliability analysis, which would include sub-hourly, stability, and AC power flow analysis." In fact, page xviii of that study qualitatively concludes "Additional challenges to power system planning and operation would arise in a high renewable electricity future, including management of low-demand periods." http://www.nrel.gov/docs/fy12osti/52409-1.pdf

	45%	NREL	2016	*Low-Carbon Grid Study*
West	35%	GE Energy	2010	*Western Wind and Solar Integration Study: Phase 1*
	17%	LBNL, ANL, NREL	2013	*Integrating Solar PV in Utility System Operations*
	30%	Xcel Energy	2011	*Wind Induced Coal Plant Cycling Costs and the Implications of Wind Curtailment for Public Service of Colorado*
	18%*	Navigant, Sandia, PNNL	2011	*Large-Scale Solar Integration Study*
	17%	Idaho Power	2014	*Solar Integration Study Report*
	9%	Portland General Electric	2014	*2013 Integrated Resource Plan: Appendix D PGE Wind Integration Study Phase 4*
	47%*	PacifiCorp	2017	*2017 Integrated Resource Plan*
ERCOT	17%	GE Energy	2008	*Analysis of Wind Generation Impact on ERCOT Ancillary Services Requirements*
	47%	Brattle	2013	*Exploring Natural Gas and Renewables in ERCOT Part II: Future Generation Scenarios for Texas*
Eastern Interconnection	30%	EnerNex	2011	*Eastern Wind Integration and Transmission Study*
	25%#	GE Energy	2013	*Eastern Frequency Response Study*
	30%	NREL	2016	*Eastern Renewable Generation Integration Study*
Central	40%	EnerNex et al.	2010	*Nebraska Statewide Wind Integration Study*
	40%	Charles River Associates	2010	*SPP WITF Wind Integration Study*
	60%#	SPP	2016	*2016 Wind Integration Study*
Central and Southeast	20%	EPRI and LCG	2011	*DOE: Integrating Midwest Wind Energy into Southeast Electricity Markets*
Southeast	7%	PNNL	2014	*Duke Energy Photovoltaic Integration Study: Carolinas Service Areas*
Mid-Atlantic	30%	GE Energy	2014	*PJM Renewable Integration Study*
	21%	Navigant	2016	*Virginia Solar Pathways Project: Study 2 - Solar PV Generation System Integration Impacts*
Midwest	50%	GE Energy	2014	*Minnesota Renewable Energy Integration and Transmission Study*
	37%*	Northern States Power	2015	*2015 Resource Plan: Appendix E – Renewable Energy*
New York	12%	NYISO	2010	*Growing Wind: Final Report of the NYISO 2010 Wind Generation Study*
	15%	NYISO	2016	*Solar Impact on Grid Operations-An Initial Assessment*
New England	24%	GE Energy	2010	*New England Wind Integration Study*

Hawaii	20%	NREL and GE Energy	2013	*Hawaii Solar Integration Study*

Notes: VRE penetration listed as percentage of annual energy (i.e. MWH, not MW), except where marked (# indicates instantaneous penetration, * indicates VRE nameplate as percentage of peak load); VRE includes only wind and solar.

Appendix C: Power Plant Cycling

Traditional baseload power plants were designed to operate primarily at constant output levels with limited cycling.[472] As the electricity system continues to evolve and market conditions change, these plants are increasingly following load or being required to more frequently adjust the load and the on/off dispatch of their units. The extra costs incurred to do so can affect a plant's retirement decision.

Every time a power plant is turned off and on, the boiler, steam lines, turbine, and auxiliary components go through unavoidably large thermal and pressure stresses, which cause damage.[473] This damage is made worse for high-temperature components by the phenomenon called creep-fatigue interaction. While cycling-related increases in failure rates may not be noted immediately, critical components will eventually start to fail. Shorter component life expectancies will result in higher plant equivalent forced outage rates[jjj] and/or higher capital and maintenance costs to replace components at or near the end of their service lives.[474] In addition, it may result in shortened overall plant life. How soon these detrimental effects will occur depends on the amount of creep damage present and the specific types and frequency of the cycling.

Several VRE integration studies, including those performed by NREL and the Western Electricity Coordinating Council, have recognized that high penetration of VRE into the wholesale electricity markets could increase cycling of conventional power plants.[475] Today, coal unit cycling does occur with current levels of wind and solar.[kkkk] [476] [477] [478] The retirement of many of the older, smaller coal-fired units that have provided cycling operation in the past will require more flexibility in the remaining coal fleet through improved technologies.[479]

General Electric has also studied the effects of cycling on power plant maintenance and operations and observes the following:

- Wear-and-tear cycling costs can increase with the changing power portfolio or fuel prices.
- These costs are generator-specific. They can impact financial viability of generators.
- Incorporating cycling costs into commitment and dispatch decisions can change these decisions.
- Solar and wind generation resources have different impacts on cycling.
- Operational and/or physical changes to coal/gas plants can increase flexibility. Retrofits have the potential to increase overall profitability. [480]

The cycling issues described above have similar impacts on gas-fired steam and older, combined-cycle generators. Some coal and NGCC units can (and have) made capital investments to improve their cycling performance to remain competitive.[481]

[jjj] NERC defines equivalent forced outage rates as "the probability that a unit will not meet its demand periods for generating requirements because of forced outages or deratings." http://www.nerc.com/pa/RAPA/Pages/SummerVsWinterEFORdRates.aspx

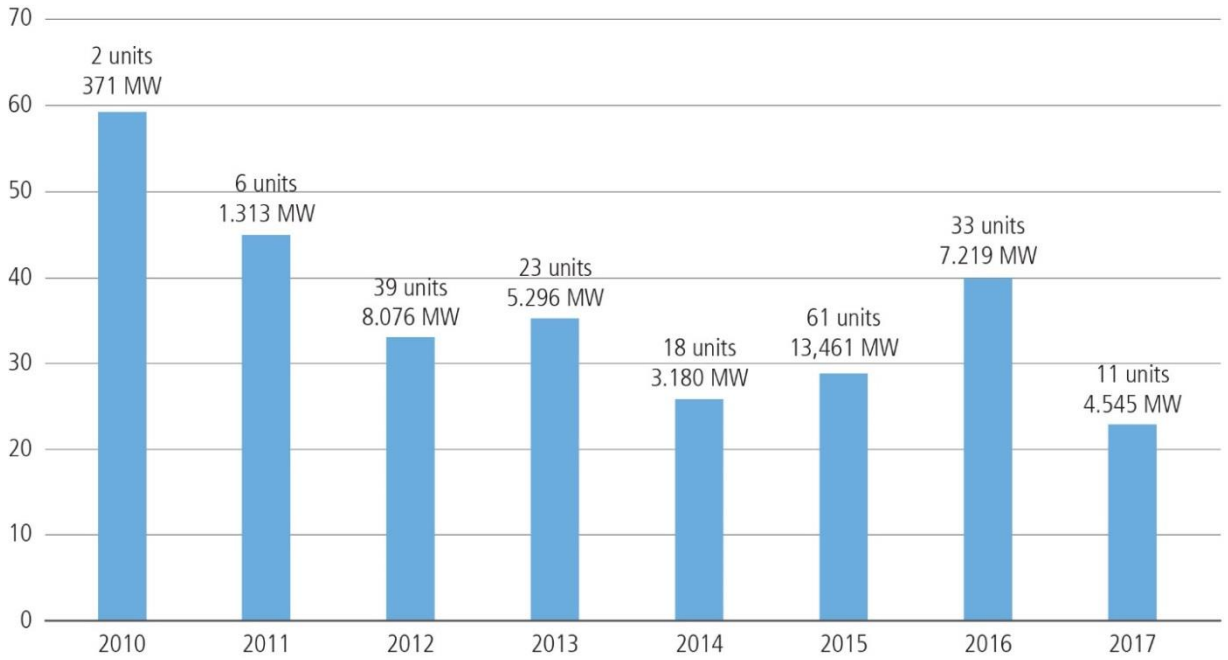
[kkkk] "Existing thermal generation plants are being forced to cycle more with the addition of intermittent wind generation and low variable cost base-load generation." http://www.energy-tech.com/ram/article_65131bb2-42d0-11e6-8c80-e729cc172758.html

Existing U.S. nuclear power plants were designed with a similar goal of operations at a set generation output, and—with few exceptions—they were not designed with flexible operation modes. Fuel is loaded in 18-month or 24-month cycles, thus keeping the marginal cost of operation low. The U.S. Nuclear Regulatory Commission prohibits nuclear power plant control systems from interfacing or being automatically controlled from grid network control systems,[482] so what limited load following is allowed must be scheduled from one to three days in advance and is in small increments of power output.[483]

Nuclear units receive no benefit to load following or ramping, as they do not save on fuel costs. Like fossil plants, ramping a nuclear plant will also result in more wear and tear due to thermal gradients and mechanical stresses and will likely increase capital expenditures. Less restrictive, but still carefully controlled, nuclear load following is permitted and utilized in other countries, such as France, for which nuclear has a higher percentage of electricity output on the system.

A review of the literature about coal plant cycling by Argonne National Laboratory[484] reports that coal plant heat rates increase with plant age, while plant availability decreases. Cycling and load following exacerbate the effects of plant aging and reduce component life.[485] These operational patterns impose higher costs (including maintenance and fuel costs), as well as lower capacity factors (Figure 8.1).[IIII]

Figure 8.1. Average Three-Year Capacity Factors for Retired U.S. Coal Plants[486]



Plants that have retired since 2010 tended to have lower average capacity factors.

[IIII] A lower capacity factor means fixed costs are spread over fewer operating hours (i.e. megawatt-hours), which in turn means higher unit costs ($/megawatt-hour).

Endnotes

[1] "Frequently Asked Questions: How Many Power Plants Are There in the United States?," Energy Information Administration, accessed October 19, 2016, http://www.eia.gov/tools/faqs/faq.cfm?id=65&t=2, quoted in Department of Energy (DOE), Transforming the Nation's Electricity System: The Second Installment of The Quadrennial Energy Review (Washington, DC: DOE, January 2017), https://www.energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review--Second%20Installment%20%28Full%20Report%29.pdf.

[2] Ellen Flynn Giles and Kathy L. Brown, eds., *2015 UDI Directory of Electric Power Producers and Distributors: 123rd Edition of the Electrical World Directory* (New York, NY: Platts, 2014), vi–vii, https://www.platts.com/im.platts.content/downloads/udi/eppd/eppddir.pdf, quoted in Department of Energy (DOE), *Transforming the Nation's Electricity System: The Second Installment of The Quadrennial Energy Review* (Washington, DC: DOE, January 2017), https://www.energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review--Second%20Installment%20%28Full%20Report%29.pdf.

[3] Julia Pyper, "The US Solar Market Is Now 1 Million Installations Strong," *Greentech Media*, April 21, 2016, https://www.greentechmedia.com/articles/read/The-U.S.-Solar-Market-Now-One-Million-Installations-Strong, quoted in Department of Energy (DOE), *Transforming the Nation's Electricity System: The Second Installment of The Quadrennial Energy Review* (Washington, DC: DOE, January 2017), https://www.energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review--Second%20Installment%20%28Full%20Report%29.pdf.

[4] "Electric Substations," Platts, generated March 6, 2009, http://www.platts.com/IM.Platts.Content/ProductsServices/Products/gismetadata/substatn.pdf quoted Department of Energy (DOE), *Transforming the Nation's Electricity System: The Second Installment of The Quadrennial Energy Review* (Washington, DC: DOE, January 2017), https://www.energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review--Second%20Installment%20%28Full%20Report%29.pdf.

[5] Ellen Flynn Giles and Kathy L. Brown, eds., *2015 UDI Directory of Electric Power Producers and Distributors: 123rd Edition of the Electrical World Directory* (New York, NY: Platts, 2014), vi–vii, https://www.platts.com/im.platts.content/downloads/udi/eppd/eppddir.pdf, quoted in Department of Energy (DOE), *Transforming the Nation's Electricity System: The Second Installment of The Quadrennial Energy Review* (Washington, DC: DOE, January 2017), https://www.energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review--Second%20Installment%20%28Full%20Report%29.pdf.

[6] Ellen Flynn Giles and Kathy L. Brown, eds., *2015 UDI Directory of Electric Power Producers and Distributors: 123rd Edition of the Electrical World Directory* (New York, NY: Platts, 2014), vi, https://www.platts.com/im.platts.content/downloads/udi/eppd/eppddir.pdf, quoted in Department of Energy (DOE), *Transforming the Nation's Electricity System: The Second Installment of The Quadrennial Energy Review* (Washington, DC: DOE, January 2017), https://www.energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review--Second%20Installment%20%28Full%20Report%29.pdf.

[7] "Electric Power Sales, Revenue, and Energy Efficiency Form EIA-861 Detailed Data Files," Energy Information Administration, last modified October 6, 2016, https://www.eia.gov/electricity/data/eia861/, as quoted in Department of Energy (DOE), *Transforming the Nation's Electricity System: The Second Installment of The Quadrennial Energy Review* (Washington, DC: DOE, January 2017), https://www.energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review--Second%20Installment%20%28Full%20Report%29.pdf.

[8] International Monetary Fund, *World Economic Outlook Database, Entire Dataset, by Country Groups, GDP, Current Prices* (International Monetary Fund, April 2016), https://www.imf.org/external/pubs/ft/weo/2016/01/weodata/download.aspx, quoted in Department of Energy (DOE), *Transforming the Nation's Electricity System: The Second Installment of The Quadrennial Energy Review* (Washington, DC: DOE, January 2017), https://www.energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review--Second%20Installment%20%28Full%20Report%29.pdf.

[9] Sara Hoff, "U.S. Electric System Is Made Up of Interconnections and Balancing Authorities," *Today In Energy*, Energy Information Administration, July 20, 2017, https://www.eia.gov/todayinenergy/detail.php?id=27152.

[10] EIA, Internal Analysis, June 2017.

[11] PJM Interconnection, "PJM Provides the Following Documents and Information for the Department's Consideration as It Prepares Its Report in Response to the Secretary's Memorandum of April 14, 2017," sent by PJM Interconnection to the Department of Energy, May 3, 2017.

[12] North American Electric Reliability Corporation (NERC), "Synopsis of NERC Reliability Assessments, the Changing Resource Mix, and the Impacts of Conventional Generation Retirements," unpublished materials submitted to the Department of Energy, May 9, 2017.

[13] Adapted from Federal Energy Regulatory Commission (FERC), *Reliability Primer* (Washington, DC: FERC, December 2016), 15, https://www.ferc.gov/legal/staff-reports/2016/reliability-primer.pdf.

[14] *Merriam-Webster*, s.v. "premature," https://www.merriam-webster.com/dictionary/premature.

[15] North American Electric Reliability Corporation (NERC), "Synopsis of NERC Reliability Assessments, the Changing Resource Mix, and the Impacts of Conventional Generation Retirements," unpublished materials submitted to the Department of Energy, May 9, 2017.

[16] SANS Industrial Control Systems and Electricity Information Sharing and Analysis Center (E-ISAC), *Analysis of the Cyber Attack on the Ukrainian Power Grid: Defense Use Case* (Washington, DC: E-ISAC, March 2016), https://ics.sans.org/media/E-ISAC_SANS_Ukraine_DUC_5.pdf.

[17] "Form EIA-860m: Preliminary Monthly Electric Generator Inventory," Energy Information Administration, March 2017, https://www.eia.gov/electricity/data/eia860m/.

[18] Energy Information Administration, "Alaska State Profile and Energy Estimates," October 2016, https://www.eia.gov/state/analysis.php?sid=AK.

[19] Gerry Cauley (President and CEO, North American Electric Reliability Corporation), letter to Energy Secretary Rick Perry, May 9, 2017.

[20] Energy Information Administration (EIA), *Monthly Energy Review* (Washington, DC: EIA, June 2017), DOE/EIA-0035(2017/6), Table 7.2a, https://www.eia.gov/totalenergy/data/monthly/#electricity.

[21] Energy Information Administration (EIA), *Monthly Energy Review* (Washington, DC: EIA, June 2017), DOE/EIA-0035(2017/6), Table 7.6, https://www.eia.gov/totalenergy/data/monthly/#electricity.

[22] "Form EIA-860m: Preliminary Monthly Electric Generator Inventory," Energy Information Administration, March 2017, https://www.eia.gov/electricity/data/eia860m/, and internal analysis, June 2017.

[23] Energy Information Administration (EIA), *Electric Power Monthly* (Washington, DC: EIA, June 2017). https://www.eia.gov/electricity/monthly/.

[24] N. Kumar, P. Besuner, S. Lefton, D. Agan, and D. Hilleman, *Power Plant Cycling Costs* (Golden, CO: National Renewable Energy Laboratory, April 2012), iv, http://www.nrel.gov/docs/fy12osti/55433.pdf.

[25] Department of Energy (DOE), *Transforming the Nation's Electricity System: The Second Installment of the Quadrennial Energy Review* (Washington, DC: DOE, January 2017), 3-73, https://www.energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review--Second%20Installment%20%28Full%20Report%29.pdf.

[26] "Form EIA-860m: Preliminary Monthly Electric Generator Inventory," Energy Information Administration, March 2017, https://www.eia.gov/electricity/data/eia860m/.

[27] "Form EIA-860m: Preliminary Monthly Electric Generator Inventory," Energy Information Administration, March 2017, https://www.eia.gov/electricity/data/eia860m/.

[28] Massachusetts et al. v. Environmental Protection Agency et al., 549 U.S. 497 (2007), https://www.law.cornell.edu/supct/html/05-1120.ZS.html.

[29] "Form EIA-860m: Preliminary Monthly Electric Generator Inventory," Energy Information Administration, March 2017, https://www.eia.gov/electricity/data/eia860m/.

[30] U.S. Energy Information Administration, "EIA-860 Electric Power Annual: Existing Capacity by Energy Source, by Producer, by State Back to 2000," November 2016, https://www.eia.gov/electricity/data.php#gencapacity.

[31] Energy Information Administration (EIA), "Monthly Update to Annual Electric Generator Report," March 2017, https://www.eia.gov/electricity/data/eia860m/.

[32] Scott Jell, "Most coal plants in the United States were built before 1990," Today in Energy, Energy Information Administration, April 17, 2017, https://www.eia.gov/todayinenergy/detail.php?id=30812.

[33] Energy Information Administration (EIA), *Monthly Energy Review* (Washington, DC: EIA, July 2017), Table 6.2, https://www.eia.gov/totalenergy/data/monthly/pdf/sec6_4.pdf.

[34] "Form EIA-860m: Preliminary Monthly Electric Generator Inventory" Energy Information Administration, March 2017, https://www.eia.gov/electricity/data/eia860m/.

[35] U.S. Energy Information Administration, "Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2017," April 2017, https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf.

[36] "Form EIA-860m: Preliminary Monthly Electric Generator Inventory," Energy Information Administration, March 2017, https://www. eia.gov/electricity/data/eia860m/.

[37] Scott Jell, "Most Coal Plants in the United States Were Built before 1990," *Today in Energy*, Energy Information Administration, April 17, 2017, https://www.eia.gov/todayinenergy/detail.php?id=30812.

[38] Richard J. Campbell, *Increasing the Efficiency of Existing Coal-Fired Power Plants* (Washington, DC: Congressional Research Service, December 20, 2013), R43343, https://fas.org/sgp/crs/misc/R43343.pdf.

[39] Energy Information Administration, "Today in Energy: Most coal plants in the United States were built before 1990," Accessed July 2017, https://www.eia.gov/todayinenergy/detail.php?id=30812.

[40] Energy Information Administration (EIA), "Monthly Update to Annual Electric Generator Report," March 2017, https://www.eia.gov/electricity/data/eia860m/.

[41] Energy Information Administration (EIA), "Monthly Update to Annual Electric Generator Report," March 2017, https://www.eia.gov/electricity/data/eia860m/.

[42] Owen Comstock, "Coal Made Up More Than 80% of Retired Electricity Generating Capacity in 2015," *Today in Energy,* Energy Information Administration, March 8, 2016, https://www.eia.gov/todayinenergy/detail.php?id=25272.

[43] Energy Information Administration, "Update on Retirements of Coal-Fired Power Plants" (presented to Secretary Ernest Moniz, November 8, 2016).

[44] Energy Information Administration (EIA), "Monthly Update to Annual Electric Generator Report," March 2017, https://www.eia.gov/electricity/data/eia860m/.

[45] Owen Comstock, "Coal Made Up More Than 80% of Retired Electricity Generating Capacity in 2015," *Today in Energy,* Energy Information Administration, March 8, 2016, https://www.eia.gov/todayinenergy/detail.php?id=25272.

[46] "Table B-1. Employees on Nonfarm Payrolls by Industry Sector and Selected Industry Detail," Department of Labor, Bureau of Labor Statistics, accessed November 4, 2016, http://www.bls.gov/news.release/empsit.t17.htm.

[47] Energy Information Administration, "U.S. Coal Flow, 2016," accessed August 7, 2017, https://www.eia.gov/totalenergy/data/monthly/pdf/flow/coal.pdf

[48] Energy Information Administration (EIA), *Monthly Energy Review* (Washington, DC: EIA, December 2016), Tables 3.7, 4.3, and 6.7, http://www.eia.gov/totalenergy/data/monthly/.

[49] "Quarterly Census of Employment and Wages," Department of Labor, Bureau of Labor Statistics, accessed August 4, 2017, http://www.bls.gov/cew/.

[50] Ed Malley, "Coal Power Plant Post-Retirement Options," POWER, September 1, 2016, http://www.powermag.com/coal-power-plant-post-retirement-options/.

[51] Augustine Kwon, "Natural Gas Generators Make Up the Largest Share of Overall U.S. Generation Capacity," *Today in Energy*, Energy Information Administration, April 20, 2017, https://www.eia.gov/todayinenergy/detail.php?id=30872.

[52] "Form EIA-860m: Preliminary Monthly Electric Generator Inventory," Energy Information Administration, March 2017, https://www. eia.gov/electricity/data/eia860m/.

[53] Augustine Kwon, "Natural Gas Generators Make Up the Largest Share of Overall U.S. Generation Capacity," *Today in Energy*, Energy Information Administration, April 20, 2017, https://www.eia.gov/todayinenergy/detail.php?id=30872.

[54] Energy Information Administration (EIA) analysis of data from "Form EIA-860," EIA, https://www.eia.gov/electricity/data/eia860/, and "Form EIA-923," EIA, https://www.eia.gov/electricity/data/eia923/.

[55] David Hurlbut, Scott Haase, Clayton Barrows, Lori Bird, Greg Brinkman, Jeff Cook, Megan Day, Victor Diakov, Elaine Hale, et al., *Navajo Generating Station & Federal Resource Planning: Volume 1: Sectoral, Technical, and Economic Trends* (Golden, CO: National Renewable Energy Laboratory, November 2016), NREL/TP-6A20-66506, http://www.nrel.gov/docs/fy17osti/66506.pdf.

[56] Energy Information Administration (EIA), *Electric Power Monthly* (Washington, DC: EIA, May 2017), Table 6.7.A, https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_6_07_a.

[57] Energy Information Administration (EIA), "Monthly Update to Annual Electric Generator Report," March 2017, https://www.eia.gov/electricity/data/eia860m/

[58] "Most Generator Retirements over the Past Decade Were Older Natural Gas-Fired Units," *Today in Energy*, Energy Information Administration, December 13, 2011, https://www.eia.gov/todayinenergy/detail.php?id=4290.

[59] Department of Energy (DOE), *Transforming the Nation's Electricity System: The Second Installment of The Quadrennial Energy Review* (Washington, DC: DOE, January 2017), 3-20, https://www.energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review--Second%20Installment%20%28Full%20Report%29.pdf.

[60] Michael Mobilia, "Most U.S. Nuclear Power Plants Were Built between 1970 and 1990," *Today in Energy*, Energy Information Administration, April 27, 2017, https://www.eia.gov/todayinenergy/detail.php?id=30972.

[61] "Form EIA-860m: Preliminary Monthly Electric Generator Inventory," Energy Information Administration, March 2017, https://www. eia.gov/electricity/data/eia860m/.

[62] Energy Information Administration (EIA), "Monthly Update to Annual Electric Generator Report," March 2017, https://www.eia.gov/electricity/data/eia860m/.

[63] U.S. Nuclear Regulatory Commission, "Backgrounder on Power Uprates for Nuclear Plants," April 2016, https://www.nrc.gov/reading-rm/doc-collections/fact-sheets/power-uprates.html.

[64] Nuclear Energy Institute (NEI), "Environment Emissions Prevented," August 2017, https://www.nei.org/Knowledge-Center/Nuclear-Statistics/Environment-Emissions-Prevented.

[65] Nuclear Energy Institute, *Nuclear Energy's Economic Benefits—Current and Future* (Washington, DC: Nuclear Energy Institute, April 2014), https://www.nei.org/corporatesite/media/filefolder/policy/papers/jobs.pdf.

[66] Department of Energy (DOE), *Transforming the Nation's Electricity System: The Second Installment of The Quadrennial Energy Review* (Washington, DC: DOE, January 2017), https://www.energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review--Second%20Installment%20%28Full%20Report%29.pdf.

[67] Webber, Michael W. University of Texas. "Why the withering nuclear power industry threatens US national security", The Conversation, August 10, 2017, https://theconversation.com/why-the-withering-nuclear-power-industry-threatens-us-national-security-82351

[68] Robert Walton, "Exelon, New York Regulators Defend Nuclear Credits under Clean Energy Standard," *Utility Dive*, February 1, 2017, http://www.utilitydive.com/news/exelon-new-york-regulators-defend-nuclear-credits-under-clean-energy-stand/435232/.

[69] Robert Walton, "Exelon, New York Regulators Defend Nuclear Credits under Clean Energy Standard," *Utility Dive*, February 1, 2017, http://www.utilitydive.com/news/exelon-new-york-regulators-defend-nuclear-credits-under-clean-energy-stand/435232/.

[70] Ronaldo Szilard, Phil Sharpe, Edward Kee, Edward Davis, and Eugene Grencheck, *Economic and Market Challenges Facing the U.S. Nuclear Commercial Fleet Energy* (Idaho National Laboratory and Center for Advanced Energy Studies, September 2016), https://gain.inl.gov/Shared%20Documents/Economics-Nuclear-Fleet.pdf.

[71] Ronaldo Szilard, Phil Sharpe, Edward Kee, Edward Davis, and Eugene Grencheck, Economic and Market Challenges Facing the U.S. Nuclear Commercial Fleet Energy (Idaho National Laboratory and Center for Advanced Energy Studies, September 2016), https://gain.inl.gov/Shared%20Documents/Economics-Nuclear-Fleet.pdf.

[72] Nuclear Energy Institute, "Nuclear by the Numbers," February 2017, https://www.nei.org/CorporateSite/media/filefolder/Policy/Wall%20Street/Nuclear_by_the_Numbers.pdf?ext=.pdf.

[73] Energy Information Agency, Today in Energy "Three Mile Island is the latest nuclear power plant to announce retirement plans," June 13, 2017, https://www.eia.gov/todayinenergy/detail.php?id=31612.

[74] : Energy Information Agency, Today in Energy "Three Mile Island is the latest nuclear power plant to announce retirement plans," June 13, 2017, https://www.eia.gov/todayinenergy/detail.php?id=31612.

[75] "Status of License Renewal Applications and Industry Activities," Nuclear Regulatory Commission, last modified June 27, 2017, https://www.nrc.gov/reactors/operating/licensing/renewal/applications.html.

[76] "Status of License Renewal Applications and Industry Activities," Nuclear Regulatory Commission, last modified June 27, 2017, https://www.nrc.gov/reactors/operating/licensing/renewal/applications.html.

[77] "U.S. Nuclear Operating Plant Basic Information," Nuclear Energy Institute, last modified April 2017, https://www.nei.org/Knowledge-Center/Nuclear-Statistics/US-Nuclear-Power-Plants/US-Nuclear-Operating-Plant-Basic-Information.

[78] Nuclear Energy Institute "Nuclear Costs in Context" April 2017. www.nei.org/Master-Document-Folder/Backgrounders/White-Papers/Nuclear-Costs-in-Context.

[79] Nicholas Steckler, "Half of U.S. Nuclear Power Plants are Underwater," Bloomberg New Energy Finance, June 13, 2017

[80] Nuclear Regulatory Commission, "Status of License Renewal Applications and Industry Activities," June 27, 2017, https://www.nrc.gov/reactors/operating/licensing/renewal/applications.html.

[81] Nuclear Energy Institute, "License Renewal of Nuclear Power Plants," November 2016, https://www.nei.org/Master-Document-Folder/Backgrounders/Fact-Sheets/License-Renewal-of-Nuclear-Power-Plants.

[82] Light Water Reactor Sustainability Program, U.S. Department of Energy Office of Nuclear Energy (Estimate provided by senior program staff).

[83] Chris Mudrick, "Industry Perspective: Overcoming Revenue Challenges" (presented at the Energy Information Administration's 2017 Energy Conference, Washington, DC, June 26, 2017), https://www.eia.gov/conference/2017/pdf/presentations/chris_mudrick.pdf.

[84] S. Nuclear Regulatory Commission, "Status of License Renewal Applications and Industry Activities," June 27, 2017, https://www.nrc.gov/reactors/operating/licensing/renewal/applications.html.

[85] Energy Information Agency, Today in Energy "Three Mile Island is the latest nuclear power plant to announce retirement plans," June 13, 2017, https://www.eia.gov/todayinenergy/detail.php?id=31612.

[86] Nuclear Energy Institute, "Nuclear by the Numbers," February 2017, https://www.nei.org/CorporateSite/media/filefolder/Policy/Wall%20Street/Nuclear_by_the_Numbers.pdf?ext=.pdf.

[87] Department of Energy (DOE), *Transforming the Nation's Electricity System: The Second Installment of The Quadrennial Energy Review* (Washington, DC: DOE, January 2017), 3-16, https://www.energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review--Second%20Installment%20%28Full%20Report%29.pdf.

[88] Office of Energy Efficiency & Renewable Energy, "2014 Hydropower Market Report," April 2015, https://energy.gov/sites/prod/files/2015/05/f22/2014%20Hydropower%20Market%20Report_20150512_rev6.pdf

[89] R. Uria-Martinez, P. O'Connor, and M. Johnson, "Hydropower Market Report: 2017 Update (April)," Oak Ridge National Laboratory, April 2017, https://energy.gov/eere/water/downloads/2014-hydropower-market-report.

[90] Energy Information Administration (EIA), *Monthly Energy Review* (Washington, DC: EIA, June 2016), http://www.eia.gov/totalenergy/data/monthly.

[91] Department of Energy (DOE), *Transforming the Nation's Electricity System: The Second Installment of The Quadrennial Energy Review* (Washington, DC: DOE, January 2017), 3-16, https://www.energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review--Second%20Installment%20%28Full%20Report%29.pdf.

[92] Allen McFarland, "Hydroelectric Generators Are among the United States' Oldest Power Plants," *Today in Energy*, Energy Information Administration, March 13, 2017, https://www.eia.gov/todayinenergy/detail.php?id=30312.

[93] Department of Energy (DOE), *Hydropower Vision: A New Chapter for America's First Renewable Electricity Source* (Oak Ridge, TN: DOE, 2016), https://energy.gov/sites/prod/files/2016/10/f33/HydropowerVision-10262016_0.pdf.

[94] R. Uria-Martinez, P. O'Connor, and M. Johnson, *2014 Hydropower Market Report* (Department of Energy, Wind and Water Power Technologies Office, April 2015), https://energy.gov/eere/water/downloads/2014-hydropower-market-report.

[95] J. Snell, D. Prowse, and K. Adams, "The Changing Role of Hydropower: From Cheap Local Energy Supply to Strategic Regional Resource," *International Journal of Water Resources Development* 30, no. 1 (2014): 121–134, http://dx.doi.org/10.1080/07900627.2013.860771.

[96] Department of Energy (DOE), *Hydropower Vision: A New Chapter for America's First Renewable Electricity Source* (Oak Ridge, TN: DOE, 2016), https://energy.gov/sites/prod/files/2016/10/f33/HydropowerVision-10262016_0.pdf.

[97] R. Uria-Martinez, P. O'Connor, and M. Johnson, *2014 Hydropower Market Report* (Department of Energy, Wind and Water Power Technologies Office, April 2015), https://energy.gov/eere/water/downloads/2014-hydropower-market-report.

[98] R. Uria-Martinez, P. O'Connor, and M. Johnson, "Hydropower Market Report: 2017 Update (April)," Oak Ridge National Laboratory, April 2017, https://energy.gov/eere/water/downloads/2014-hydropower-market-report.

[99] FERC, "Annual Charges," https://www.ferc.gov/industries/hydropower/annual-charges.asp

[100] U.S. Energy Information Administration (EIA), "Monthly Updated to the Annual Electric Generator Report," Form EIA-860m, March 2017, https://www.eia.gov/electricity/data/eia860m/

[101] Allen McFarland, "Total U.S. Energy Production Falls in 2016 after Six Consecutive Years of Increases," *Today in Energy*, Energy Information Administration, March, 31, 2017, https://www.eia.gov/todayinenergy/detail.php?id=30592.

[102] "Henry Hub Natural Gas Spot Price," Energy Information Administration, data from Thomson Reuters, last modified August 2, 2017, https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm.

[103] "Henry Hub Natural Gas Spot Price" Energy Information Administration, data from Thomson Reuters, last modified August 2, 2017, https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm.

[104] Energy Information Administration, *Trends in U.S. Oil and Natural Gas Upstream Costs* (Washington, DC: EIA, March 2016), 5, https://www.eia.gov/analysis/studies/drilling/pdf/upstream.pdf.

[105] Energy Information Administration (EIA), *Electric Power Monthly* (Washington, DC: EIA, May 2017), Table 6.7a, https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_6_07_a.

[106] SNL Energy, obtained by DOE using their database of electricity spot prices and Intercontinental Exchange natural gas spot prices taken from ABB's Energy Velocity Suite.

[107] Energy Information Administration, "Henry Hub Natural Gas Spot Price," Accessed July 2017, https://www.eia.gov/dnav/ng/hist/rngwhhdM.htm.

[108] Energy Information Administration (EIA), *Capital Cost Estimates for Utility Scale Electricity Generating Plants* (Washington, DC: EIA, November 2016), Table 1, https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capcost_assumption.pdf.

[109] "Assessment of Relative Benefit/Impact: Which Is the Best Generation Technology?" Electric Power Research Institute, http://sites.epri.com/refcard/comparison.html.

[110] Energy Information Administration (EIA), *Monthly Energy Review* (Washington, DC: EIA, July 2017), https://www.eia.gov/totalenergy/data/monthly/#electricity.

[111]Chinese University of Hong Kong, "Single Cycle Gas Turbine Power Plant," CLP Power Hong Kong Ltd. and the Hongkong Electric Co. Ltd., 2014, http://www.hk-phy.org/energy/power/elect_phy/flash/powerplant_e.html.

[112] Tyler Hodge, "Average Utilization for Natural Gas Combined-Cycle Plants Exceeded Coal Plants in 2015," *Today in Energy,* Energy Information Administration, April 4, 2016, https://www.eia.gov/todayinenergy/detail.php?id=25652.

[113] EPSA Analysis: Cara Marcy, Jeffrey Logan, James McCall, Francisco Flores-Espino, Aaron Bloom, Jørn Aabakken, Wesley Cole, Thomas Jenkins, Gian Porro, Chang Liu, et al., *Electricity Generation Baseline Report* (Golden, CO: National Renewable Energy Laboratory, October 2016), https://energy.gov/epsa/downloads/electricity-generation-baseline-report.

[114] Jaime López, "Combustion Engine vs Gas Turbine: Ramp Rate," Wärtsilä, accessed December 15, 2016, http://www.wartsila.com/energy/learning-center/technical-comparisons/combustion-engine-vs-gas-turbine-ramp-rate.

[115] International Energy Agency (IEA) Environmental Projects Ltd, *Operating Flexibility of Power Plants with CCS* (Cheltenham, UK: IEA Environmental Projects Ltd, June 2012), 14, http://hub.globalccsinstitute.com/sites/default/files/publications/104631/operating-flexibility-power-plants-ccs.pdf.

[116] Energy Information Administration (EIA), Monthly Energy Review (Washington, DC: EIA, June 2017), https://www.eia.gov/totalenergy/data/monthly/pdf/sec13_6.pdf. Data from EIA, "Form EIA-923: Power Plant Operations Report" and predecessor form(s), including "Form EIA-90: Power Plant Report," "Form EIA-920: Combined Heat and Power Plant Report," and "Form EIA-860: Annual Electric Generator Report."

[117] "Form EIA-860m: Preliminary Monthly Electric Generator Inventory," Energy Information Administration, March 2017, https://www.eia.gov/electricity/data/eia860m/.

Energy Information Administration (EIA), *Monthly Energy Review* (Washington, DC: EIA, July 2017), Table A6, https://www.eia.gov/totalenergy/data/monthly/pdf/sec13_6.pdf; data from "Form EIA-923: Power Plant Operations

Report" and predecessor form(s), including "Form EIA-906: Power Plant Report," "Form EIA-920: Combined Heat and Power Plant Report," and "Form EIA-860: Annual Electric Generator Report."

[118] "Form EIA-860m: Preliminary Monthly Electric Generator Inventory," Energy Information Administration, March 2017, https://www.eia.gov/electricity/data/eia860m/.

[119] "Form EIA-860m: Preliminary Monthly Electric Generator Inventory," Energy Information Administration, March 2017, https://www.eia.gov/electricity/data/eia860m/.

[120] Kristine Harmon and Daniel Shea, *State Options to Keep Nuclear Power in the Generation Mix* (Denver, CO: National Conference of State Legislatures, January 2017), http://www.ncsl.org/Portals/1/Documents/energy/StateOptions_NuclearPower_f05_WEB.pdf.

[121] "Administrative Consent Order in the Matter of Exelon Generation Company, LLC. Oyster Creek Generating Station," State of New Jersey Department of Environmental Protection, December 9, 2010, http://www.nj.gov/dep/barnegatbay/docs/aco_oyster.creek.pdf.

[122] Cooling Water Intake Rule, 79 Fed. Reg. 48299 (2014) (40 C.F.R. § 122, 125), https://www.federalregister.gov/documents/2014/08/15/2014-12164/national-pollutant-discharge-elimination-system-final-regulations-to-establish-requirements-for.

[123] "Memorandum: Clean Water Act Section 316(b) Regulations for Cooling Water Intake Structures at Existing Facilities: NPDES Permitting Process When Federally-Listed Threatened and Endangered Species and/or Designated Critical Habitat Are or May Be Present," Environmental Protection Agency, December 11, 2014, https://www.epa.gov/sites/production/files/2015-04/documents/cooling-water_esa-instructional-memo_12-11-2014.pdf.

[124] Cooling Water Intake Rule, 79 Fed. Reg. 48299 (2014) (40 C.F.R. § 122, 125), https://www.federalregister.gov/documents/2014/08/15/2014-12164/national-pollutant-discharge-elimination-system-final-regulations-to-establish-requirements-for

[125] "Cross-State Air Pollution Rule (CSAPR) Basics," Environmental Protection Agency, accessed October 13, 2016, https://www.epa.gov/csapr/cross-state-air-pollution-rule-csapr-basics.

[126] "Cross-State Air Pollution Rule (CSAPR) Basics," Environmental Protection Agency, accessed October 13, 2016, https://www.epa.gov/csapr/cross-state-air-pollution-rule-csapr-basics.

[127] Steam Electric Effluent Limitations Guidelines, 39 Fed. Reg. 8294 (1974) (40 C.F.R. § 423), https://www.epa.gov/eg/steam-electric-power-generating-effluent-guidelines-documents-related-1974-initial-rulemaking.

[128] Mercury and Air Toxics Standards, 77 Fed. Reg. 9304 (2012) (40 C.F.R. § 60, 63).

[129] "EPA Announces Mercury and Air Toxics Standards (MATS) for Power Plants – Technical Information," Environmental Protection Agency, December 21, 2011, https://www.epa.gov/mats/epa-announces-mercury-and-air-toxics-standards-mats-power-plants-technical-information.

[130] Coal Combustion Residuals Rule, 80 Fed. Reg. 21302 (2015) (40 C.F.R. § 257, 261).

[131] Carbon Pollution Emission Guidelines for Existing Stationary Sources, 80 Fed. Reg. 64662 (2015) (40 C.F.R. § 60).

[132] Fitch Ratings, *Time to Retire? U.S. Coal Plants in Environmental Crosshairs* (Fitch Ratings, February 28, 2011).

[133] ABB Ventyx Velocity Suite dataset. Accessed August 2017.

[134] The National Coal Council, *Reliable & Resilient, The Value of Our Existing Coal Fleet: An Assessment of Measures to Improve Reliability & Efficiency While Reducing Emissions* (Washington, DC: The National Coal Council, May 2014), 2–3, http://www.nationalcoalcouncil.org/reports/1407/NCCValueExistingCoalFleet.pdf.

[135] Fitch Ratings, *Time to Retire? U.S. Coal Plants in Environmental Crosshairs* (Fitch Ratings, February 28, 2011).

[136] Dale Probasco and Bob Ruhlman, "Coal-Fired Generation Cost and Performance Trends," *Power,* May 1, 2011, http://www.powermag.com/coal-fired-generation-cost-and-performance-trends/?pagenum=3.

[137] "27 Gigawatts of Coal-Fired Capacity to Retire over Next Five Years," *Today in Energy,* Energy Information Administration, July 27, 2012, https://www.eia.gov/todayinenergy/detail.php?id=7290.

[138] Michael Leff, "Coal-Fired Power Plant Operators Consider Emissions Compliance Strategies," *Today in Energy,* Energy Information Administration, March 28, 2014, https://www.eia.gov/todayinenergy/detail.php?id=15611.

[139] Sara Hoff and Jonathan DeVilbiss, "EIA Electricity Generator Data Show Power Industry Response to EPA Mercury Limits," *Today in Energy*, July 7, 2016, https://www.eia.gov/todayinenergy/detail.php?id=26972.

[140] James E. McCarthy, *EPA's Utility MACT: Will the Lights Go Out?* (Washington, DC: Congressional Research Service, January 9, 2012), R42144, 4, https://www.eenews.net/assets/2012/01/19/document_gw_03.pdf.

[141] Sara Hoff and Jonathan DeVilbiss, "EIA Electricity Generator Data Show Power Industry Response to EPA Mercury Limits," *Today in Energy*, July 7, 2016, https://www.eia.gov/todayinenergy/detail.php?id=26972.

[142] "New Source Review (NSR) Permitting," Environmental Protection Agency, accessed July 13, 2017, https://www.epa.gov/nsr.

[143] The National Coal Council, *Leveling the Playing Field: Policy Parity for Carbon Capture and Storage Technologies* (Washington, DC: The National Coal Council, November 2015), http://www.nationalcoalcouncil.org/studies/2015/Leveling-the-Playing-Field-for-Low-Carbon-Coal-Fall-2015.pdf

[144] The National Coal Council, *Reliable & Resilient, The Value of Our Existing Coal Fleet: An Assessment of Measures to Improve Reliability & Efficiency While Reducing Emissions* (Washington, DC: The National Coal Council, May 2014), 5, http://www.nationalcoalcouncil.org/reports/1407/NCCValueExistingCoalFleet.pdf.

[145] Environmental Protection Agency (EPA), *New Source Review: Report to the President* (EPA, June 2002), 1, https://www.epa.gov/sites/production/files/2015-08/documents/nsr_report_to_president.pdf.

[146] Steven F. Hayward, "Making Sense of 'New Source Review,'" American Enterprise Institute, July 1, 2003, http://www.aei.org/publication/making-sense-of-new-source-review/.

[147] Sue Tierney, "EPA Proposed Utility Air Toxics Rule—Managing Compliance in Reliable Ways," Congressional Staff Briefing, May 9, 2011, quoted in James McCarthy and Claudia Copeland, *EPA's Regulation of Coal-Fired Power: Is a "Train Wreck" Coming?* (Washington, DC: Congressional Research Service, August 8, 2011), AR-1162, https://www3.epa.gov/region1/npdes/merrimackstation/pdfs/ar/AR-1162.pdf.

[148] Energy Information Administration, "Update on Retirements of Coal-Fired Power Plants" (presented to Secretary Ernest Moniz, November 8, 2016).

[149] Guggenheim Securities, as reported in David Schlissel, *The Beginning of the End: Fundamental Changes in Energy Markets Are Undermining the Financial Viability of Coal-Fired Power Plants in Texas* (Institute for Energy Economics and Financial Analysis, September 2016), http://ieefa.org/wp-content/uploads/2016/09/The-Beginning-of-the-End_September-2016.pdf.

[150] U.S. Energy Information Administration, "Annual Energy Outlook 2014 with projections to 2040: Table A9. Electricity generating capacity (gigawatts)," April 2014, page A-20, https://www.eia.gov/outlooks/archive/aeo14/pdf/0383(2014).pdf.

[151] Energy Information Administration, "Update on Retirements of Coal-Fired Power Plants" (presented to Secretary Ernest Moniz, November 8, 2016).

[152] "Frequently Asked Questions: How Much Carbon Dioxide Is Produced When Different Fuels Are Burned?," Energy Information Administration, June 8, 2017, https://www.eia.gov/tools/faqs/faq.php?id=73&t=11.

[153] Warren Lasher, *Summary of Impacts of Environmental Regulations in the ERCOT Region* (Electric Reliability Council of Texas, March 31, 2015), https://www.ferc.gov/CalendarFiles/20150327133925-Lasher,%20ERCOT.pdf.

[154] Energy Information Administration (EIA), *Electric Power Annual 2015* (Washington, DC: EIA, 2016), Table 8.2, https://www.eia.gov/electricity/annual/html/epa_08_02.html.

[155] "Form EIA-860m: Preliminary Monthly Electric Generator Inventory," Energy Information Administration, March 2017, https://www.eia.gov/electricity/data/eia860m/.

[156] Kristine Harmon and Daniel Shea, "State Options to Keep Nuclear Power in the Generation Mix," NCSL, January 2017. http://www.ncsl.org/Portals/1/Documents/energy/StateOptions_NuclearPower_f05_WEB.pdf

[157] State of New Jersey Department of Environmental Protection, Administrative Consent Order In the Matter of Exelon Generation Company, LLC. Oyster Creek Generating Station, December 9, 2010. http://www.nj.gov/dep/barnegatbay/docs/aco_oyster.creek.pdf

[158] "Administrative Consent Order in the Matter of Exelon Generation Company, LLC. Oyster Creek Generating Station," State of New Jersey Department of Environmental Protection, December 9, 2010, http://www.nj.gov/dep/barnegatbay/docs/aco_oyster.creek.pdf.

[159] Sam Batkins, Philip Rossetti, and Dan Goldbeck, "Putting Nuclear Regulatory Costs in Context," American Action Forum, July 12, 2017, https://www.americanactionforum.org/research/putting-nuclear-regulatory-costs-context/.

[160] R. Uria-Martinez, P. O'Connor, and M. Johnson, "Hydropower Market Report: 2017 Update (April)," Oak Ridge National Laboratory, April 2017, https://energy.gov/eere/water/downloads/2014-hydropower-market-report.

[161] Aaron Levine, Katherine R. Young, and Kermit Witherbee, "Coordinating Permit Offices and the Development of Utility-Scale Geothermal Energy" (presented at the 2013 Geothermal Resources Council Annual Meeting, Las Vegas, NV, October 1, 2013), http://www.nrel.gov/docs/fy14osti/60276.pdf.

[162] U.S. Department of Energy (DOE), "2014 Hydropower Market Report," Prepared by Oak Ridge National Laboratory, April 2015, Page 44, https://energy.gov/sites/prod/files/2015/05/f22/2014%20Hydropower%20Market%20Report_20150512_rev6.pdf.

[163] Energy Information Administration (EIA), *Monthly Energy* Review (Washington, DC: EIA, June 2017), Table 7.2b, https://www.eia.gov/totalenergy/data/monthly/pdf/sec7_6.pdf.

[164] U.S. Department of Energy (DOE), *Wind Vision: A New Era for Wind Power in the United States* (DOE, 2015), https://www.energy.gov/sites/prod/files/WindVision_Report_final.pdf.

[165] April Lee, "U.S. Wind Generating Capacity Surpasses Hydro Capacity at the End of 2016," *Today in Energy,* Energy Information Administration, March 6, 2017, https://www.eia.gov/todayinenergy/detail.php?id=30212.

[166] April Lee, "U.S. Wind Generating Capacity Surpasses Hydro Capacity at the End of 2016," *Today in Energy,* Energy Information Administration, March 6, 2017, https://www.eia.gov/todayinenergy/detail.php?id=30212.

[167] Galen Barbose, *U.S. Renewables Portfolio Standards: 2016 Annual Status Report* (Lawrence Berkeley National Laboratory, April 2016), LBNL-1005057, https://emp.lbl.gov/sites/all/files/lbnl-1005057.pdf

[168] Galen Barbose, *U.S. Renewables Portfolio Standards: 2016 Annual Status Report* (Lawrence Berkeley National Laboratory, April 2016), LBNL-1005057, https://emp.lbl.gov/sites/all/files/lbnl-1005057.pdf.

[169] Ran Fu, Donald Chung, Travis Lowder, David Feldman, Kristen Ardani, and Robert Margolis, *U.S. Solar Photovoltaic System Cost Benchmark: Q1 2016* (Golden, CO: National Renewable Energy Laboratory, September 2016), NREL/TP-6A20-66532, Fig. ES-1, http://www.nrel.gov/docs/fy16osti/66532.pdf .

[170] Christopher Mone, Maureen Hand, Mark Bolinger, Joseph Rand, Donna Heimiller, and Jonathan Ho, *2015 Cost of Wind Energy Review* (Golden, CO: National Renewable Energy Laboratory, May 2017), NREL/TP-6A20-66861, Fig. 35, http://www.nrel.gov/docs/fy17osti/66861.pdf.

[171] Ryan H. Wiser and Mark Bolinger, *2015 Wind Technologies Market Report* (Department of Energy, August 2016), LBNL-1005951, https://emp.lbl.gov/publications/2015-wind-technologies-market-report.

[172] "Renewable Electricity Production Tax Credit (PTC)," Department of Energy, https://energy.gov/savings/renewable-electricity-production-tax-credit-ptc.

[173] "Business Energy Investment Tax Credit (ITC)," Department of Energy, https://energy.gov/savings/business-energy-investment-tax-credit-itc.

[174] "Form EIA-860m: Preliminary Monthly Electric Generator Inventory," Energy Information Administration, March 2017, https://www.eia.gov/electricity/data/eia860m/.

[175] Ryan Wiser, Andrew Mills, et al., *Impacts of Variable Renewable Energy on Bulk Power System Assets, Pricing and Costs*, June 2017 draft (Lawrence Berkeley National Laboratory, forthcoming).

[176] Ryan Wiser, Andrew Mills, et al., *Impacts of Variable Renewable Energy on Bulk Power System Assets, Pricing and Costs*, June 2017 draft (Lawrence Berkeley National Laboratory, forthcoming).

[177] Management Information Services, *Two Thirds of a Century and $1 Trillion+ U.S. Energy Incentives: Analysis of Federal Expenditures for Energy Development, 1950–2016* (Management Information Services, May 2017), https://www.nei.org/CorporateSite/media/filefolder/Backgrounders/White-Papers/EnergyIncentives-MISI-0517.pdf?ext=.pdf.

[178] BW Research, *U.S. Energy and Employment Report* (Washington, DC: Department of Energy, January 2017), https://energy.gov/sites/prod/files/2017/01/f34/2017%20US%20Energy%20and%20Jobs%20Report_0.pdf.

[179] BW Research, *U.S. Energy and Employment Report* (Washington, DC: Department of Energy, January 2017), https://energy.gov/sites/prod/files/2017/01/f34/2017%20US%20Energy%20and%20Jobs%20Report_0.pdf.

[180] The Solar Foundation (TSF), National Solar Jobs Census 2015 (Washington, DC: TSF, January 2016), http://www.thesolarfoundation.org/wp-content/uploads/2016/10/TSF-2015-National-Solar-Jobs-Census.pdf.

[181] Energy Information Administration (EIA),"May 2017 Monthly Energy Review," May 25, 2017, accessed: June 6, 2017, https://www.eia.gov/totalenergy/data/monthly/.

[182] Federal Reserve Bank of St. Louis, "Real Gross Domestic Product, Billions of Chained 2009 Dollars, Annual, Seasonally Adjusted Annual Rate," Federal Reserve Economic Data, May 26, 2017, accessed: June 6, 2017, https://fred.stlouisfed.org/series/GDPC1

[183] Energy Information Administration, "Annual Energy Outlook 2017," January 2017, https://www.eia.gov/outlooks/aeo/pdf/0383(2017).pdf.

[184] Energy Information Administration (EIA),"May 2017 Monthly Energy Review," May 25, 2017, accessed: June 6, 2017, https://www.eia.gov/totalenergy/data/monthly/.

[185] Federal Reserve Bank of St. Louis, "Real Gross Domestic Product, Billions of Chained 2009 Dollars, Annual, Seasonally Adjusted Annual Rate," Federal Reserve Economic Data, May 26, 2017, accessed: June 6, 2017, https://fred.stlouisfed.org/series/GDPC1.

[186] U.S. Congressional Budget Office (CBO), "January 2017 Baseline Forecast-Data Release (Calendar Year)," The Budget and Economic Outlook: 2017 to 2027, accessed: June 7, 2017, https://www.cbo.gov/publication/52370.

[187] U.S. Energy Information Administration (EIA), "Electricity Supply, Disposition, Prices, and Emissions," Annual Energy Outlook 2017, January 2017, accessed: June 7, 2017, https://www.eia.gov/outlooks/aeo/.

[188] Lisa C. Schwartz, Max Wei, William Morrow, Jeff Deason, Steven R. Schiller, Greg Leventis, Sarah Smith, et al. *Electricity End Uses, Energy Efficiency, and Distributed Energy Resources Baseline* (Berkeley, CA: Lawrence Berkeley National Laboratory, January 2017), https://energy.gov/epsa/downloads/electricity-end-uses-energyefficiency-and-distributed-energy-resources-baseline.

[189] Steve Nadel, Neal Elliott, and Therese Langer, *Energy Efficiency in the United States: 35 Years and Counting* (Washington, DC: American Council for an Energy-Efficient Economy, June 2015), Report E1502, 1–2, http://aceee.org/research-report/e1502.

[190] Hillard Huntington, *Structural Change and U.S. Energy Use: Recent Patterns* (Stanford, CA: Stanford University Energy Modeling Forum, July 2009), https://web.stanford.edu/group/emf-research/docs/occasional_papers/op65.pdf.

[191] Energy Information Agency (EIA), *Annual Energy Outlook Retrospective Review: Evaluation of 2014 and Prior Reference Case Projections* (Washington, DC: EIA, March 2015), Table 15, https://www.eia.gov/outlooks/aeo/retrospective/excel/table_15.xls. Original EIA file updated with AEO 2001 through 2016 electricity sales data from "Table 8. Electricity Supply, Disposition, Prices, and Emissions."

[192] Department of Energy (DOE), *Transforming the Nation's Electricity System: The Second Installment of The Quadrennial Energy Review* (Washington, DC: DOE, January 2017), S-7, https://www.energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review--Second%20Installment%20%28Full%20Report%29.pdf.

[193] Energy Information Administration (EIA), *Annual Energy Outlook 2017 with Projections to 2050* (Washington, DC: EIA, January 2017), No CPP Scenario Table 9, https://www.eia.gov/outlooks/aeo/tables_side.php.

[194] Energy Information Administration (EIA), *Annual Energy Outlook 2017 with Projections to 2050* (Washington, DC: EIA, January 2017), No CPP Scenario, https://www.eia.gov/outlooks/aeo/tables_side.php.

[195] PJM Interconnection, "PJM Provides the Following Documents and Information for the Department's Consideration as It Prepares Its Report in Response to the Secretary's Memorandum of April 14, 2017," sent by PJM Interconnection to the Department of Energy, May 3, 2017.

[196] Energy Information Administration analysis using ABB's Energy Velocity Suite collection of the Environmental Protection Agency's continuous emission monitoring system data.

[197] Postponement of Certain Compliance Dates for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, 82 Fed. Reg. 26017 (proposed June 6, 2017) (to be codified at 40 C.F.R. § 423), https://www.regulations.gov/document?D=EPA-HQ-OW-2009-0819-6485.

[198] Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category; Extension of Public Comment Period, 78 Fed. Reg. 41907 (proposed July 12, 2013) (to be codified at 40 C.F.R. § 423), https://www.regulations.gov/document?D=EPA-HQ-OW-2009-0819-3132.

[199] Steam Electric Power Generating Effluent Guidelines – 2015 Final Rule, U.S. Environmental Protection Agency (EPA), https://www.epa.gov/eg/steam-electric-power-generating-effluent-guidelines-2015-final-rule.

[200] Utility Water Act Group, "Utility Water Act Group's Petition for Rulemaking to Reconsider and Administratively Stay the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category; Final Rule, 80 Fed. Reg. 67,838-903 (Nov. 3, 2015)," letter to Environmental Protection Agency Administrator Scott Pruitt, March 24, 2017,

https://www.epa.gov/sites/production/files/2017-03/documents/letter_to_epa_submitting_petition_for_reconsideration_w_exhibits-c_508.pdf.

[201] Environmental Protection Agency, *Economic Analysis for the Final Section 316(b) Existing Facilities Rule* (Washington, DC: EPA, May 2014), EPA-821-R-14-001, https://www.epa.gov/sites/production/files/2015-05/documents/cooling-water_phase-4_economics_2014.pdf.

[202] Warren Lasher, *Summary of Impacts of Environmental Regulations in the ERCOT Region* (Electric Reliability Council of Texas, March 31, 2015), https://www.ferc.gov/CalendarFiles/20150327133925-Lasher,%20ERCOT.pdf.

[203] SNL Energy, "SNL Day-Ahead Prices," accessed June 15, 2017, subscription service; ABB Velocity Suite, "Daily Power Prices," accessed June 15, 2017, subscription service.

[204] "Final Rule: Disposal of Coal Combustion Residuals from Electric Utilities," Environmental Protection Agency, accessed June 30, 2017, https://www.epa.gov/coalash/coal-ash-rule.

[205] 80 Fed. Reg. 74 (2015) (40 C.F.R. § 257, 261), https://www.gpo.gov/fdsys/pkg/FR-2015-04-17/pdf/2015-00257.pdf.

[206] "Map of States Covered by CSAPR," Environmental Protection Agency, https://www.epa.gov/airmarkets/map-states-covered-csapr.

[207] "Visibility – Regulatory Actions," Environmental Protection Agency, https://www.epa.gov/visibility/visibility-regulatory-actions.

[208] "Visibility and Haze – Rules and Regulations" *Federal Register* 77, no. 110 (June 7, 2012): 33642. https://www.epa.gov/visibility/final-action-address-regional-haze-2012.

[209] John Larsen (analyst, Rhodium Group), cited in Benjamin Storrow, "Big, Young Coal Plants Are Closing. Is It a New Trend?," *E&E News*, April 27, 2017, https://www.eenews.net/stories/1060053677.

[210] Department of Energy (DOE), *Hydropower Vision: A New Chapter for America's First Renewable Electricity Source* (Oak Ridge, TN: DOE, 2016), https://energy.gov/sites/prod/files/2016/10/f33/Hydropower-Vision-10262016_0.pdf.

[211] R. Uria-Martinez, P. O'Connor, and M. Johnson, "Hydropower Market Report: 2017 Update (April)," Oak Ridge National Laboratory, April 2017, https://energy.gov/eere/water/downloads/2014-hydropower-market-report.

[212] National Academies of Sciences, Engineering, and Medicine. 2017. Enhancing the Resilience of the Nation's Electricity System. Washington, DC: The National Academies Press. https://doi.org/10.17226/24836

[213] Department of Energy (DOE), *Transforming the Nation's Electricity System: The Second Installment of The Quadrennial Energy Review* (Washington, DC: DOE, January 2017), p.S-4, https://www.energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review--Second%20Installment%20%28Full%20Report%29.pdf.https://www.energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review%20Summary%20for%20Policymakers.pdf

[214] Gerry Cauley (president and CEO, North American Electric Reliability Corporation), letter to Energy Secretary Rick Perry, May 9, 2017.

[215] Department of Energy (DOE), *Transforming the Nation's Electricity System: The Second Installment of The Quadrennial Energy Review* (Washington, DC: DOE, January 2017),p. https://www.energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review--Second%20Installment%20%28Full%20Report%29.pdf..https://www.energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review%20Summary%20for%20Policymakers.pdf

[216] Gerry Cauley (president and CEO, North American Electric Reliability Corporation), letter to Energy Secretary Rick Perry, May 9, 2017.

[217] Gerry Cauley, "Remarks of Gerry Cauley, President and CEO, North American Electric Reliability Corporation," (presented at Federal Energy Regulatory Commission Reliability Technical Conference, Panel I: Overview on the State of Reliability, June 22, 2017), https://www.ferc.gov/CalendarFiles/20170717080645-Cauley,%20NERC.pdf.

[218] Severe Impact Resilience Task Force, *Severe Impact Resilience: Considerations and Recommendations* (North American Electric Reliability Corporation, May 2012), http://www.nerc.com/comm/OC/SIRTF%20Related%20Files%20DL/SIRTF_Final_May_9_2012-Board_Accepted.pdf.

[219] North American Electric Reliability Corporation (NERC), *State of Reliability 2017* (Atlanta, GA: NERC, June 2017), http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/SOR_2017_MASTER_20170613.pdf.

[220] Federal Energy Regulatory Commission, communication with Department of Energy, July 2017.

[221] Gerry Cauley, "Written Statement of Gerry Cauley, President and CEO, North American Electric Reliability Corporation, to the Quadrennial Energy Review Task Force" (public comment presented at *Transforming the Nation's Electricity System: Second Installment of the Quadrennial Energy Review,* Public Meeting No. 1, Washington, DC, February 4, 2016), https://www.energy.gov/epsa/downloads/qer-second-installment-public-meeting-washington-dc.

[222] Thomas Burgess and Gerry Cauley, "Remarks of Thomas Burgess, Vice President and Director of Reliability Assessment and Performance Analysis, and Gerry Cauley, President and CEO, North American Electric Reliability Corporation" (presented at Federal Energy Regulatory Commission Reliability Technical Conference, Panel II: Emerging Issues, June 10, 2014), http://www.nerc.com/news/testimony/Testimony%20and%20Speeches/Panel%202%20-%20Cauley%20Burgess.pdf.

[223] Mark Lauby and John Moura, "Remarks of Mark G. Lauby, Senior Vice President and Chief Reliability Officer, and John Moura, Director, Reliability Assessment and System Analysis" (presented at Federal Energy Regulatory Commission Reliability Technical Conference, Panel II: Emerging Issues, June 4, 2015), http://www.nerc.com/news/testimony/Testimony%20and%20Speeches/FERC%20Technical%20Conference%20June%204%202015%20Lauby%20Moura%20Panel%20II.pdf.

[224] Mark Lauby, "Remarks of Mark Lauby, Senior Vice President and Chief Reliability Officer, North American Electric Reliability Corporation" (presented at Federal Energy Regulatory Commission Reliability Technical Conference, Panel II: Emerging Issues, June 1, 2016), http://www.nerc.com/news/testimony/Documents/Lauby.pdf.

[225] Mark Lauby, "Remarks of Mark Lauby, Senior Vice President and Chief Reliability Officer, North American Electric Reliability Corporation" (presented at Federal Energy Regulatory Commission Reliability Technical Conference, Panel III: The Potential for Long-term and Large-Scale Disruptions to the Bulk-Power System, June 22, 2017), https://www.ferc.gov/CalendarFiles/20170717080646-Lauby,%20NERC.pdf.

[226] North American Electric Reliability Corporation (NERC), *State of Reliability 2017* (Atlanta, GA: NERC, June 2017), http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/SOR_2017_MASTER_20170613.pdf.

[227] "Essential Reliability Services Working Group (ERSWG) and Distributed Energy Resources Task Force (DERTF)," North American Electric Reliability Corporation, http://www.nerc.com/comm/Other/Pages/Essential-Reliability-Services-Task-Force-(ERSTF).aspx.

[228] "Integration of Variable Generation Task Force (IVGTF)," North American Electric Reliability Corporation, http://www.nerc.com/comm/PC/Pages/Integration%20of%20Variable%20Generation%20Task%20Force%20(IVGTF)/Integration-of-Variable-Generation-Task-Force-IVGTF.aspx.

[229] Gerry Cauley (president and CEO, North American Electric Reliability Corporation), letter to Energy Secretary Rick Perry, May 9, 2017.

[230] North American Electric Reliability Corporation, staff analysis requested by Department of Energy, June 2017.

[231] North American Electric Reliability Corporation, modified from 2016 Long-Term Reliability Assessment, requested by Department of Energy, June 2017.

[232] Noha Abdel-Karim and David Calderon, "Impact of Wind and Solar Variability on the Resource Adequacy for North American Bulk Power System," NERC, 2016, http://ieeexplore.ieee.org/document/7764176/?reload=true.

[233] Department of Energy (DOE), *Maintaining Reliability in the Modern Power System* (Washington, DC: DOE, 2016), https://energy.gov/sites/prod/files/2017/01/f34/Maintaining%20Reliability%20in%20the%20Modern%20Power%20System.pdf.

[234] North American Electric Reliability Corporation (NERC), *Methods to Model and Calculate Capacity for Contributions of Variable Generation for Resource Adequacy Planning* (Princeton, NJ: NERC, March 2011), http://www.nerc.com/files/ivgtf1-2.pdf.

[235] NERC, "Balancing and Frequency Control – A Technical Document Prepared by the NERC Resources Subcommittee, January 2011, Accessed August 2017 http://www.nerc.com/docs/oc/rs/NERC%20Balancing%20and%20Frequency%20Control%20040520111.pdf

[236] North American Electric Reliability Corporation (NERC), *Essential Reliability Services Task Force Measures Framework Report* (Atlanta, GA: NERC, November 2015), http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Framework%20Report%20-%20Final.pdf.

[237] North American Electric Reliability Corporation (NERC), *Essential Reliability Services Task Force Measures Framework Report* (Atlanta, GA: NERC, November 2015), http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Framework%20Report%20-%20Final.pdf.

[238] Federal Energy Regulatory Commission (FERC), *Reliability Primer* (Washington, DC: FERC, December 2016), 15, https://www.ferc.gov/legal/staff-reports/2016/reliability-primer.pdf.

[239] Reactive Power Requirements for Non-Synchronous Generation, 40 C.F.R. § 35 (June 16, 2016), https://ferc.gov/whats-new/comm-meet/2016/061616/E-1.pdf.

[240] Essential Reliability Services and the Evolving Bulk-Power System—Primary Frequency Response, 18 C.F.R. § 35 (proposed November 17, 2016), https://www.ferc.gov/whats-new/comm-meet/2016/111716/E-3.pdf.

[241] NERC, "Balancing and Frequency Control – A Technical Document Prepared by the NERC Resources Subcommittee, January 2011, Accessed August 2017 http://www.nerc.com/docs/oc/rs/NERC%20Balancing%20and%20Frequency%20Control%20040520111.pdf

[242] NERC, "Balancing and Frequency Control – A Technical Document Prepared by the NERC Resources Subcommittee, January 2011, Accessed August 2017 http://www.nerc.com/docs/oc/rs/NERC%20Balancing%20and%20Frequency%20Control%20040520111.pdf

[243] Joseph H. Eto, John Undrill, Peter Mackin, Ron Daschmans, Ben Williams, Brian Haney, Randall Hunt, Jeff Ellis, Howard Illian, et al., *Use of Frequency Response Metrics to Assess the Planning and Operating Requirements for Reliable Integration of Variable Renewable Generation* (Berkeley, CA: Lawrence Berkeley National Laboratory, December 2010), LBNL-4142E, https://www.ferc.gov/industries/electric/indus-act/reliability/frequencyresponsemetrics-report.pdf.

[244] Joseph H. Eto, John Undrill, Peter Mackin, Ron Daschmans, Ben Williams, Brian Haney, Randall Hunt, Jeff Ellis, Howard Illian, et al., *Use of Frequency Response Metrics to Assess the Planning and Operating Requirements for Reliable Integration of Variable Renewable Generation* (Berkeley, CA: Lawrence Berkeley National Laboratory, December 2010), LBNL-4142E, https://www.ferc.gov/industries/electric/indus-act/reliability/frequencyresponsemetrics-report.pdf.

[245] North American Electric Reliability Corporation (NERC), *Essential Reliability Services Task Force (ERSTF) Scope* (Washington, DC: NERC, 2014), http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Scope_ERSTF_Final. pdf.

[246] Frequency Regulation Compensation in the Organized Wholesale Power Markets, 18 C.F.R. § 35 (October 20, 2011), https://www.ferc.gov/whats-new/comm-meet/2011/102011/E-28.pdf.

[247] PJM Interconnection, *Appendix to PJM's Evolving Resource Mix and System Reliability* (PJM Interconnection, March 30, 2017), http://www.pjm.com/~/media/library/reports-notices/special-reports/20170330-appendix-to-pjms-evolving-resource-mix-and-system-reliability.ashx.

[248] Debra Lew of GE Energy Consulting, e-mail message to author(s), May 31, 2017

[249] General Electric, "Impact of Frequency Responsive Wind Plant Controls on Grid Performance. Last modified December 20, 2010. http://web.mit.edu/windenergy/windweek/Presentations/GE%20Impact%20of%20Frequency%20Responsive%20Wind%20Plant%20Controls%20Pres%20and%20Paper.pdf

[250] M Kinterner-Meyer, J Homer, P Balducci, M Weimar, I Shavel, M Hagerty, N Powers, Y Yang, R Lueken, "Valuation of Electric Power System Services and Technologies," Pacific Northwest National Lab and The Brattle Group, August 2016, http://www.brattle.com/system/publications/pdfs/000/005/389/original/Valuation_of_Electric_Power_System_Services_and_Technologies.pdf?1484183040

[251] "FERC Proposes to Integrate Electricity Storage into Organized Markets," Federal Energy Regulatory Commission, November 17, 2016, https://www.ferc.gov/media/news-releases/2016/2016-4/11-17-16-E-1.asp#.WYHpMaqWyUk.

[252] Imre Gyuk, Mark Johnson, John Vetrano, Kevin Lynn, William Parks, Rachna Handa, Landis Kannberg, Sean Hearne, Karen Waldrip, and Ralph Braccio, *Grid Energy Storage* (Department of Energy, December 2013), Table 5, https://energy.gov/sites/prod/files/2014/09/f18/Grid%20Energy%20Storage%20December%202013.pdf.

[253] Imre Gyuk, Mark Johnson, John Vetrano, Kevin Lynn, William Parks, Rachna Handa, Landis Kannberg, Sean Hearne, Karen Waldrip, and Ralph Braccio, *Grid Energy Storage* (Department of Energy, December 2013), Table 5, https://energy.gov/sites/prod/files/2014/09/f18/Grid%20Energy%20Storage%20December%202013.pdf.

[254] Enerknol Research, "New York to Set Energy Storage Targets by Next Year", June 2017, Accessed August, 2017 https://enerknol.com/wp-content/uploads/2017/06/EKR-PU-New-York-Energy-Storage-Legislation-6-30-2017.pdf

[255] Utility Dive, "New York expected to set high bar for energy storage after target bill passage", June 2017, Accessed August 2017, http://www.utilitydive.com/news/new-york-expected-to-set-high-bar-for-energy-storage-after-target-bill-pass/445845/

[256] U.S. Department of Energy (DOE), "Annual U.S. Transmission Data Review", October 2016, Accessed August 2017, https://www.energy.gov/sites/prod/files/2017/04/f34/Annual%20US%20Transmission%20Data%20Review%202016_0.pdf.

[257] Southwest Power Pool, *The Value of Transmission* (Southwest Power Pool, January 2016), https://spp.org/value-of-transmission/.

[258] "Order No. 1000 – Transmission Planning and Cost Allocation," Federal Energy Regulatory Commission, last modified October 26, 2016, https://www.ferc.gov/industries/electric/indus-act/trans-plan.asp.

[259] Federal Energy Regulatory Commission (FERC), "Competitive Transmission Development Rates (Docket No. AD16-18-000)" (FERC Technical Conference, June 27–28, 2016), https://www.ferc.gov/EventCalendar/EventDetails.aspx?ID=8285&CalType=&CalendarID=116&Date=06/27/2016&View=Listview.

[260] Rory Sweeney, "Five Years Later, FERC Takes Another Look at Order 1000," *RTO Insider*, July 4, 2016, https://www.rtoinsider.com/ferc-takes-another-look-order-1000-28637/.

[261] Corina Rivera Linares, "FERC Order 1000 Is Working Slowly, But It Is Working," *Electric Light & Power*, November 29, 2016, http://www.elp.com/articles/2016/11/ferc-order-1000-is-working-slowly-but-it-is-working.html.

[262] James Hoecker, "Making the Grid Great Again," *Public Utilities Fortnightly 2.0*, June 15, 2017, http://www.wiresgroup.com/docs/PUF2_0_June15_2017.pdf.

[263] Reiten, Patrick. "Oral Remarks of Patrick Reiten, President & CEO, Pacific Power, to the Quadrennial Energy Review Task Force" (at Energy Transmission, Storage, and Distribution Infrastructure: First Installment of the Quadrennial Energy Review, Public Meeting No. 5, Portland, OR, July 11, 2014), pp. 41-43 of transcript, https://www.energy.gov/sites/prod/files/2014/08/f18/transcript_portland_qer.pdf.

[264] Hoecker, James. "Making the Grid Great Again," *Public Utilities Fortnightly 2.0*, p. 16, June 15, 2017, http://www.wiresgroup.com/docs/PUF2_0_June15_2017.pdf.

[265] Cauley, Gerry. "Written Statement of Gerry Cauley, President and CEO, North American Electric Reliability Corporation, to the Quadrennial Energy Review Task Force,'' (public comment presented at *Transforming the Nation's Electricity System: Second Installment of the Quadrennial Energy Review,* Public Meeting No. 1, Washington, DC, February 4, 2016), p. 8, https://www.energy.gov/epsa/downloads/qer-second-installment-public-meeting-washington-dc.

[266]Midcontinent Independent System Operator, Multi Value Project Portfolio Analysis webpage, https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/MVPAnalysis.aspx

[267]Southwest Power Pool, "FERC Approves Highway/Byway Cost Allocation Methodology," The Org Report, https://www.spp.org/documents/12559/07_10_july_org_report.pdf

[268] Federal Energy Regulatory Commission (FERC), Order Denying In Part and Granting In Part Rehearing, Conditionally Accepting Compliance Filing, and Directing Further Compliance Filings, Docket Nos. ER10-1791-001 and ER10-1791-002, (Washington, DC: FERC, October 21, 2011), p. 7, https://www.ferc.gov/whats-new/comm-meet/2011/102011/E-11.pdf.

[269] SPP Regional State Committee, Cost Allocation Working Group, "New Member Cost AllocationReview Process," October 26, 2016, https://spp.org/documents/47372/spp%20new%20member%20cost%20allocation%20review%20process%20-%20rsc%20approved%2020161024.pdf.

[270] Edison Electric Institute, *Transmission Projects: At A Glance* (Edison Electric Institute, December 2016), v, http://www.eei.org/issuesandpolicy/transmission/Documents/Trans_Project_lowres_bookmarked.pdf.

[271] Energy Information Administration (EIA), *Monthly Energy Review* (Washington, DC: EIA, June 2017), Table 7.2b, https://www.eia.gov/totalenergy/data/monthly/pdf/sec7_6.pdf; EIA, *Annual Energy Outlook 2017 with Projections to 2050* (Washington, DC: EIA, January 2017), https://www.eia.gov/outlooks/aeo/tables_side.php.

[272] Tosha Beckford, "Wind Turbines Provide 8% of U.S. Generating Capacity, More Than Any Other Renewable Source," *Today in Energy*, Energy Information Administration, May 2, 2017, https://www.eia.gov/todayinenergy/detail.php?id=31032.

[273] Gavin Bade and Robert Walton, "CAISO: Renewables Served 42% of California Demand on May 16, Setting Record," *Utility Dive*, May 18, 2017, http://www.utilitydive.com/news/caiso-renewables-served-42-of-california-demand-on-may-16-setting-record/442926/.

[274] Electric Reliability Council of Texas (ERCOT), *Inside the Promise: 2016 State of the Grid Report* (ERCOT, 2017), http://www.ercot.com/content/wcm/lists/114739/2016_StateoftheGridReport.pdf.

[275] Tom Kleckner, "ERCOT Reaches 50% Wind Penetration Mark," *RTO Insider*, March 26, 2017, https://www.rtoinsider.com/ercot-wind-penetration-40749/.

[276] Derek Wingfield, "SPP Sets North American Record for Wind Power," Southwest Power Pool, February 13, 2017, https://www.spp.org/about-us/newsroom/spp-sets-north-american-record-for-wind-power/.

[277] "Hourly Aggregated Wind Output – 2016," Electric Reliability Council of Texas, http://mis.ercot.com/misapp/GetReports.do?reportTypeId=13424&reportTitle=Hourly%20Aggregated%20Wind%20Output&showHTMLView=&mimicKey.

[278] Adapted by AWEA from EIA, Monthly net electricity generation for all sectors, 2017, accessed at: http://www.awea.org/MediaCenter/pressrelease.aspx?ItemNumber=9999.

[279] Jaquelin Cochran, Paul Denholm, Bethany Speer, and Mackay Miller, *Grid Integration and the Carrying Capacity of the U.S. Grid to Incorporate Variable Renewable Energy* (Golden, CO: National Renewable Energy Laboratory, April 2015), NREL/TP-6A20-62607, http://www.nrel.gov/docs/fy15osti/62607.pdf.

[280] Ryan Wiser, Andrew Mills, et al., *Impacts of Variable Renewable Energy on Bulk Power System Assets, Pricing and Costs*, June 2017 draft (Lawrence Berkeley National Laboratory, forthcoming).

[281] Jaquelin Cochran, Mackay Miller, Owen Zinaman, Michael Milligan, Doug Arent, Bryan Palmintier, Mark O'Malley, et al., *Flexibility in 21st Century Power Systems* (Golden, CO: National Renewable Energy Laboratory, May 2014), NREL/TP-6A20-61721, http://www.nrel.gov/docs/fy14osti/61721.pdf.

[282] Tian Tian and Ilya Chernyakhovskiy, "Forecasting Wind and Solar Generation: Improving System Operations", last modified January 2016. https://www.nrel.gov/docs/fy16osti/65728.pdf

[283] Bonneville Power Administration, communication with Department of Energy staff, July 2017.

[284] Bonneville Power Administration, communication with Department of Energy staff, July 2017.

[285] Bonneville Power Administration, communication with Department of Energy staff, July 2017.

[286] EnerNex, *NSP Wind Integration Study* (Minneapolis, MN: Xcel Energy, August 2014), 4, https://www.xcelenergy.com/staticfiles/xe/PDF/Regulatory/16-App-M-NSP-Wind-Integration-Study-January-2015.pdf.

[287] Mickey Francis, "Monthly Renewable Electricity Generation Surpasses Nuclear for the First Time Since 1984," *Today in Energy*, Energy Information Administration, July 6, 2017, https://www.eia.gov/todayinenergy/detail.php?id=31932.

[288] Owen Comstock, "Wind and Solar in March Accounted for 10% of U.S. Electricity Generation for the First Time," *Today in Energy*, Energy Information Administration, June 14, 2017, https://www.eia.gov/todayinenergy/detail.php?id=31632.

[289] Mark Gabriel (Administrator, Western Area Power Administration), "Study Examining Electricity Markets and Reliability," memorandum for Travis Fisher, May 18, 2017.

[290] Gwen Bredehoeft and Eric Krall, "Increased Solar and Wind Electricity Generation in California Are Changing Net Load Shapes," *Today in Energy*, Energy Information Administration, December 9, 2014, https://www.eia.gov/todayinenergy/detail.php?id=19111.

[291] Kendall Bowman (vice president regulatory affairs and policy, Duke Energy Corporation), "Comments of Duke Energy Corporation to the Federal Energy Regulatory Commission's Technical Conference Concerning Implementation Issues Under the Public Utility Regulatory Policies Act of 1978 ("PURPA"), Docket No. AD16-16-000," letter to Federal Energy Regulatory Commission Secretary Kimberly D. Bose, June 7, 2016, https://www.ferc.gov/CalendarFiles/20160617152411-Bowman,%20Duke%20Energy%20-%20Long%20paper.pdf.

[292] "What the duck curve tells us about managing a green grid," California ISO, 2016, http://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf.

[293] North American Electric Reliability Corporation (NERC), *2016 Long-Term Reliability Assessment* (Atlanta, GA: NERC, December 2016), http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2016%20Long-Term%20Reliability%20Assessment.pdf.

[294] North American Electric Reliability Corporation (NERC), *1,200 MW Fault-Induced Solar Photovoltaic Resource Interruption Disturbance Report: Southern California 8/16/2016 Event* (Atlanta, GA: NERC, June 2017), 4, http://www.nerc.com/pa/rrm/ea/1200_MW_Fault_Induced_Solar_Photovoltaic_Resource_/1200_MW_Fault_Induced_Solar_Photovoltaic_Resource_Interruption_Final.pdf.

[295] North American Electric Reliability Corporation (NERC), *1,200 MW Fault-Induced Solar Photovoltaic Resource Interruption Disturbance Report: Southern California 8/16/2016 Event* (Atlanta, GA: NERC, June 2017), 4, http://www.nerc.com/pa/rrm/ea/1200_MW_Fault_Induced_Solar_Photovoltaic_Resource_/1200_MW_Fault_Induced_Solar_Photovoltaic_Resource_Interruption_Final.pdf.

[296] North American Electric Reliability Corporation (NERC), *1,200 MW Fault-Induced Solar Photovoltaic Resource Interruption Disturbance Report: Southern California 8/16/2016 Event* (Atlanta, GA: NERC, June 2017),

http://www.nerc.com/pa/rrm/ea/1200_MW_Fault_Induced_Solar_Photovoltaic_Resource_/1200_MW_Fault_Induced_Solar_Photovoltaic_Resource_Interruption_Final.pdf.

[297] Australian Energy Market Operator (AEMO), *Black System South Australia, Final Report* (Melbourne, Australia: AEMO, March 2017), https://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2017/Integrated-Final-Report-SA-Black-System-28-September-2016.pdf.

[298] Australian Energy Market Operator (AEMO), *Black System South Australia, Final Report* (Melbourne, Australia: AEMO, March 2017), https://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2017/Integrated-Final-Report-SA-Black-System-28-September-2016.pdf.

[299] Jens C. Boemer, Karsten Burges, Pavel Zolotarev, Joachim Lehner, Patrick Wajant, Markus Furst, Rainer Brohm, and Thomas Kumm, "Overview of German Grid Issues and Retrofit of Photovoltaic Power Plants in Germany for the Prevention of Frequency Stability Problems in Abnormal System Conditions of the ENTSO-E Region Continental Europe" (presented at 1st International Workshop on Integration of Solar Power into Power Systems, Aarhus, Denmark, October 2011), http://www.ecofys.com/files/files/ecofys_2011_paper_on_frequency_stability_challenge.pdf.

[300] VDE, *Power Generation Systems Connected to the Low-Voltage Distribution Network* (VDE, 2011), VDE-AR-N 405, https://shop.vde.com/download/sample/700.

[301] PJM Interconnection, *PJM's Evolving Resource Mix and System Reliability* (PJM Interconnection, March 30, 2017), http://www.pjm.com/~/media/library/reports-notices/special-reports/20170330-pjms-evolving-resource-mix-and-system-reliability.ashx.

[302] E. Ela and U. Helman, *Wholesale Electricity Market Design Initiatives in the United States: Survey and Research Needs* (Palo Alto, CA: Electric Power Research Institute, 2016), https://www.epri.com/#/pages/product/000000003002009273/.

[303] Elena Verdolini, Francesco Vona, and David Popp, *Bridging the Gap: Do Fast Reacting Fossil Technologies Facilitate Renewable Energy Diffusion?* (Cambridge, MA: National Bureau of Economic Research, July 2016), Working Paper No. 22454, http://www.nber.org/papers/w22454, as quoted in Department of Energy (DOE), *Transforming the Nation's Electricity System: The Second Installment of the Quadrennial Energy Review* (Washington, DC: DOE, January 2017), https://www.energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review--Second%20Installment%20%28Full%20Report%29.pdf.

[304] Clyde Loutan, Peter Klauer, Sirajul Chowdhury, Stephen Hall, Mahesh Morjaria, Vladimir Chadliev, Nick Milam, Christopher Milan, and Vahan Gevorgian, *Demonstration of Essential Reliability Services by a 300-MW Solar Photovoltaic Power Plant* (Golden, CO: National Renewable Energy Laboratory, March 2017), NREL/TP-5D00-67799, http://www.nrel.gov/docs/fy17osti/67799.pdf.

[305] North American Electric Reliability Corporation (NERC), *Essential Reliability Services Task Force,* (Atlanta, GA: NERC, October 2014), http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Concept%20Paper.pdf.

[306] Peter Alstone, Jennifer Potter, Mary Ann Piette, Peter Schwartz, Michael A. Berger, Laurel N. Dunn, Sarah J. Smith, et al., *Final Report on Phase 2 Results: 2015 California Demand Response Potential Study – Charting California's Demand Response Future* (Berkeley, CA: Lawrence Berkeley National Laboratory, November 2016), http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442451541.

[307] T. Markel, A. Meintz, K. Hardy, B. Chen, T. Bohn, J. Smart, D. Scoffield, et al., *Multi-Lab EV Smart Grid Integration Requirements Study Providing Guidance on Technology Development and Demonstration* (Golden, CO: National Renewable Energy Laboratory, May 2015), NREL/TP-5400-63963, http://www.nrel.gov/docs/fy15osti/63963.pdf.

[308] PJM Interconnection, *Appendix to PJM's Evolving Resource Mix and System Reliability* (PJM Interconnection, March 30, 2017), http://www.pjm.com/~/media/library/reports-notices/special-reports/20170330-appendix-to-pjms-evolving-resource-mix-and-system-reliability.ashx.

[309] PJM Interconnection, *Appendix to PJM's Evolving Resource Mix and System Reliability* (PJM Interconnection, March 30, 2017), http://www.pjm.com/~/media/library/reports-notices/special-reports/20170330-appendix-to-pjms-evolving-resource-mix-and-system-reliability.ashx.

[310] Energy Information Administration (EIA) *Electric Power Monthly* (Washington, DC: EIA, June 2017), https://www.eia.gov/electricity/monthly/.

[311] Devin Hartman, "Why Risk and Reliability Matter More than Fuel Diversity," *R Street Shorts No. 39*, May 2017, https://www.rstreet.org/wp-content/uploads/2017/05/RSTREETSHORT39.pdf.

[312] Federal Energy Regulatory Commission (FERC), "FERC Looks at Fuel Assurance Issues Following Technical Conferences," November 2014, https://www.ferc.gov/media/news-releases/2014/2014-4/11-20-14-E-2.asp#.WYnsJ6qWyUk.

[313] Federal Energy Regulatory Commission, "Decision: Docket Nos. AD13-7-000 and AD14-8-000 ," November 2014, Page 2, https://www.ferc.gov/whats-new/comm-meet/2014/112014/E-2.pdf

[314] North American Electric Reliability Corporation (NERC), *State of Reliability Report 2017* (Atlanta, GA: NERC, June 2017), http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/SOR_2017_MASTER_20170613.pdf.

[315] NYSRC I-R3: Loss of Generator Gas Supply (New York City); see also *Con Edison Dual Fuel Interconnection Requirement* for LDC-interconnected generators.

[316] S&P Global Market Intelligence, "ISO New England's Van Welie Warns Energy Crunch, Green Push Could Lead to Blackouts: Exclusive Interview," October 10, 2016, SNL, https://www.snl.com/web/client?auth=inherit#news/article?id=37939124&KPLT=6&s_data=si%3D8%26kpa%3D1ad56e55-7f17-4bee-b433-a9418c56e545%26sa%3D.

[317] ISO New England, "Winter Program Payment Rate", accessed August 2017, https://www.iso-ne.com/markets-operations/markets/winter-program-payment-rate

[318] Gerry Cauley (president and CEO, North American Electric Reliability Corporation), letter to Energy Secretary Rick Perry, May 9, 2017.

[319] Gerry Cauley (president and CEO, North American Electric Reliability Corporation), letter to Energy Secretary Rick Perry, May 9, 2017.

[320] North American Electric Reliability Corporation (NERC), *Short-Term Special Assessment: Operational Risk Assessment with High Penetration of Natural Gas-Fired Generation* (Atlanta, GA: NERC, May 2016), http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC%20Short-Term%20Special%20Assessment%20Gas%20Electric_Final.pdf.

[321] North American Electric Reliability Corporation (NERC), *2013 Special Reliability Assessment: Accommodating an Increased Dependence on Natural Gas for Electric Power – Phase II: A Vulnerability and Scenario Assessment for the North American Bulk Power System* (Washington, DC: NERC, May 2013), http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_PhaseII_FINAL.pdf.

[322] Justin Adder, *The Role of Natural Gas Storage in Maintaining Reliability of the Electric Power System* (National Energy Technology Laboratory, August 2016), https://www.netl.doe.gov/research/energy-analysis/search-publications/vuedetails?id=1824.

[323] Thomas S. Popik, "Testimony of the Foundation for Resilient Societies" (remarks presented at 2017 Federal Energy Regulatory Commission Reliability Technical Conference, June 22, 2017), https://www.ferc.gov/CalendarFiles/20170717080647-Popik,%20Resilient%20Societies.pdf.

[324] California Public Utility Commission (CPUC), California Independent System Operator (CAISO), Los Angeles Department of Water and Power (LADWP), and Southern Company, *Aliso Canyon Risk Assessment Technical Report* (CPUC, CAISO, LADPW, and Southern Co., April 2016), http://www.energy.ca.gov/2016_energypolicy/documents/2016-04-08_joint_agency_workshop/Aliso_Canyon_Risk_Assessment_Technical_Report.pdf.

[325] PJM Interconnection, *Appendix to PJM's Evolving Resource Mix and System Stability* (PJM Interconnection, March 2017), http://www.pjm.com/~/media/library/reports-notices/special-reports/20170330-appendix-to-pjms-evolving-resource-mix-and-system-reliability.ashx.

[326] North American Electric Reliability Corporation (NERC), *Polar Vortex Review* (Atlanta, GA: September 2014), 19, http://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf.

[327] Alyson Kenward, "In Tennessee, Heat Waves Diminish Nuclear Power Output," April 11, 2011, http://www.climatecentral.org/news/in-tennessee-heat-waves-frustrate-nuclear-power

[328] World Nuclear Association, "The Nuclear Fuel Cycle". Last modified March 2017. http://www.world-nuclear.org/information-library/nuclear-fuel-cycle/introduction/nuclear-fuel-cycle-overview.aspx

[329] North American Electric Reliability Corporation (NERC), *Polar Vortex Review* (Atlanta, GA: NERC, September 2014), http://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf.

[330] World Nuclear Association, "The Nuclear Fuel Cycle". Last modified March 2017. http://www.world-nuclear.org/information-library/nuclear-fuel-cycle/introduction/nuclear-fuel-cycle-overview.aspx

[331] "Electricity Monthly Update May 2017: Electric Power Sector Coal Stocks," Energy Information Administration, July 31, 2017, https://www.eia.gov/electricity/monthly/update/fossil_fuel_stocks.php

[332] "Electricity Monthly Update May 2017: Electric Power Sector Coal Stocks," Energy Information Administration, July 31, 2017, https://www.eia.gov/electricity/monthly/update/fossil_fuel_stocks.php.

[333] Federal Energy Regulatory Commission (FERC), "Coal Delivery Issues for Electric Generation: Staff Overview" (Washington, DC: FERC, December 18, 2014), Item No. A-3, https://www.ferc.gov/media/headlines/2014/2014-4/A-3-presentation-staff.pdf.

[334] Benjamin L. Preston, Scott N. Backhaus, Mary Ewers, Julia A. Phillips, Cesar A. Silva-Monroy, Jeffery E. Dagle, Alfonso G. Tarditi, John (Pat) Looney, and Thomas J. King, Jr., *Resilience of the U.S. Electricity System: A Multi-Hazard Perspective* (Department of Energy, August 2016), https://energy.gov/sites/prod/files/2017/01/f34/Resilience%20of%20the%20U.S.%20Electricity%20System%20A%20Multi-Hazard%20Perspective.pdf.

[335] Department of Energy (DOE), Transforming the Nation's Electricity System: The Second Installment of the Quadrennial Energy Review (Washington, DC: DOE, January 2017), Chapter 4, Page 23-24. Accessed August 2017. https://energy.gov/sites/prod/files/2017/01/f34/Chapter%20IV%20Ensuring%20Electricity%20System%20Reliability%2C%20Security%2C%20and%20Resilience.pdf

[336] NERC, Risk Profile #1, Changing Resource Mix. Accessed August 2017. http://www.nerc.com/comm/RISC/Documents/All%20profiles.pdf

[337] North American Electric Reliability Corporation (NERC), *Polar Vortex Review* (Atlanta, GA: NERC, September 2014), http://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf.

[338] PJM Interconnection, *Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events* (PJM Interconnection, May 8, 2014), http://www.pjm.com/~/media/library/reports-notices/weather-related/20140509-analysis-of-operational-events-and-market-impacts-during-the-jan-2014-cold-weather-events.ashx.

[339] North American Electric Reliability Corporation (NERC), *Polar Vortex Review* (Atlanta, GA: NERC, September 2014), http://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf

[340] Federal Energy Regulatory Commission (FERC), *Winter 2013–2014 Operations and Market Performance in RTOs and ISOs* (Washington, DC: FERC, April 1, 2014), AD14-8-000, https://www.ferc.gov/legal/staff-reports/2014/04-01-14.pdf.

[341] The National Coal Council, "Coal = Reliable Energy" (Washington, DC : The National Coal Council, 2015), http://www.nationalcoalcouncil.org/Documents/Energy-Education/4-Coal-Reliable-Energy-Final.pdf.

[342] PJM Interconnection, *Analysis of Operational Events and Market Impacts during the January 2014 Cold Weather Events* (PJM Interconnection, May 8, 2014), http://www.pjm.com/~/media/library/reports-notices/weather-related/20140509-analysis-of-operational-events-and-market-impacts-during-the-jan-2014-cold-weather-events.ashx.

[343] The National Coal Council, *Reliable & Resilient, The Value of Our Existing Coal Fleet: An Assessment of Measures to Improve Reliability and Efficiency While Reducing Emissions* (Washington, DC: National Coal Council, May 2014), http://www.nationalcoalcouncil.org/reports/1407/NCCValueExistingCoalFleet.pdf.

[344] The National Coal Council, *Reliable & Resilient, The Value of Our Existing Coal Fleet: An Assessment of Measures to Improve Reliability & Efficiency While Reducing Emissions* (Washington, DC: The National Coal Council, May 2014), 2, http://www.nationalcoalcouncil.org/reports/1407/NCCValueExistingCoalFleet.pdf.

[345] North American Electric Reliability Corporation (NERC), *Polar Vortex Review* (Atlanta, GA: NERC, September 2014), http://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf.

[346] U.S. Department of Energy (DOE), "Comparing the Impacts of Northeast Hurricanes on Energy Infrastructure." Table 5, p 13. Office of Electricity Delivery and Energy Reliability. April 2013. https://energy.gov/sites/prod/files/2013/04/f0/Northeast%20Storm%20Comparison_FINAL_041513b.pdf.

[347] U.S. Department of Energy (DOE), Office of Electricity Delivery and Energy (OE), *Northeast Hurricanes on Energy Infrastructure* (Washington, DC: DOE-OE, April 2013), https://energy.gov/sites/prod/files/2013/04/f0/Northeast%20Storm%20Comparison_FINAL_041513b.pdf.

[348] Tom Johnson, "PSE&G Solar Systems Took Big Hit from Hurricane Sandy," *NJ Spotlight*, July 10, 2013, http://www.njspotlight.com/stories/13/07/09/pse-g-solar-systems-take-big-hit-from-hurricane-sandy/.

[349] PJM Interconnection, *PJM's Evolving Resource Mix and System Reliability* (PJM Interconnection, March 2017), http://www.pjm.com/~/media/library/reports-notices/special-reports/20170330-pjms-evolving-resource-mix-and-system-reliability.ashx.

[350] PJM Interconnection, *PJM's Evolving Resource Mix and System Reliability* (PJM Interconnection, March 2017), http://www.pjm.com/~/media/library/reports-notices/special-reports/20170330-pjms-evolving-resource-mix-and-system-reliability.ashx.

[351] Johannes Pfeifenberger, Judy Chang, and Akarsh Sheilendranath, *Toward More Effective Transmission Planning: Addressing the Costs and Risks of an Insufficiently Flexible Electricity Grid* (The Brattle Group, April 2015), 36–37, http://wiresgroup.com/docs/reports/WIRES%20Brattle%20Rpt_TransPlanning_042315.pdf.

[352] Eric Vugrin, Anya Castillo, Cesar Silva-Monroy, *Resilience Metrics for the Electric Power System: A Performance-Based Approach* (Albuquerque, NM: Sandia National Laboratories, 2017), http://prod.sandia.gov/techlib/access-control.cgi/2017/171493.pdf.

[353] Joseph Bowring (president, Monitoring Analytics), telephone conversation with Department of Energy staff concerning his report and relevant matters based on his role as PJM market monitor, June 28, 2017.

[354] Michael Hogan, "Follow the Missing Money: Ensuring Reliability at Least Cost to Consumers in the Transition to a Low-Carbon Power System," *The Electricity Journal* 30, no. 1 (January–February 2017): 55–61, doi: 10.1016/j.tej.2016.12.006.

[355] E. Ela, M. Milligan, A. Bloom, A. Botterud, A. Townsend, and T. Levin, *Evolution of Wholesale Electricity Market Design with Increasing Levels of Renewable Generation* (Golden, CO: National Renewable Energy Laboratory, September 2014), http://www.nrel.gov/docs/fy14osti/61765.pdf.

[356] Department of Energy (DOE), *Transforming the Nation's Electricity System: The Second Installment of the Quadrennial Energy Review* (Washington, DC: DOE, January 2017), A-11, https://www.energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review--Second%20Installment%20%28Full%20Report%29.pdf.

[357] Karl McDermott, *Cost of Service Regulation In the Investor-Owned Electric Utility Industry: A History of Adaptation* (Washington, DC: Edison Electric Institute, June 2012), 22–24, http://www.eei.org/issuesandpolicy/stateregulation/Documents/COSR_history_final.pdf.

[358] Karl McDermott, *Cost of Service Regulation In the Investor-Owned Electric Utility Industry: A History of Adaptation* (Washington, DC: Edison Electric Institute, June 2012), 30, http://www.eei.org/issuesandpolicy/stateregulation/Documents/COSR_history_final.pdf.

[359] Public Utilities Regulatory Policy Act of 1978, 16 U.S.C. § 260 (1978), http://legcounsel.house.gov/Comps/PURPA78.PDF.

[360] Public Utilities Regulatory Policy Act of 1978, 16 U.S.C. § 260 (1978), http://legcounsel.house.gov/Comps/PURPA78.PDF.

[361] Energy Policy Act of 1992, 42 U.S.C. § 13201 (1992).

[362] "Renewable Energy Production Tax Credit Webpage," Department of Energy, accessed August 3, 2017, https://energy.gov/savings/renewable-electricity-production-tax-credit-ptc.

[363] Federal Energy Regulatory Commission (FERC), Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Docket Nos. RM95-8-000 and RM94-7-001, Order No. 888," Federal Energy Regulatory Commission, (Washington, DC: FERC, April 24, 1996), https://www.ferc.gov/legal/maj-ord-reg/land-docs/order888.asp.

[364] Federal Energy Regulatory Commission (FERC), *Regional Transmission Organizations, Docket No. RM99-2-000; Order No. 2000* (Washington, DC: FERC, December 1999), https://www.ferc.gov/legal/maj-ord-reg/land-docs/RM99-2A.pdf.

[365] Christine Marshall, Robert Blair, Jonathan Abe, and Christopher Clark, "FERC Order 2000 Drives RTO Initiatives; ISOs, Transcos Prevail," *Electric Light & Power*, May 1, 2001, http://www.elp.com/articles/print/volume-79/issue-5/industry-news/ferc-order-2000-drives-rto-initiatives-isos-transcos-prevail.html.

[366] Christine Marshall, Robert Blair, Jonathan Abe, and Christopher Clark, "FERC Order 2000 Drives RTO Initiatives; ISOs, Transcos Prevail," *Electric Light & Power*, May 1, 2001, http://www.elp.com/articles/print/volume-79/issue-5/industry-news/ferc-order-2000-drives-rto-initiatives-isos-transcos-prevail.html.

[367] S&P Global Market Intelligence, created by DOE staff from mapping utility website. https://www.snl.com/web/client?auth=inherit#mapping/map?mapId=1e2ae3a6-59ae-4f6c-9f4c-1023dafd3b83&share=1&bbox=-138.252%2C54.9271%2C-57.3047%2C11.2646%2C4326

[368] Department of Energy (DOE), *Transforming the Nation's Electricity System: The Second Installment of the Quadrennial Energy Review* (Washington, DC: DOE, January 2017), Fig. A-8, https://www.energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review--Second%20Installment%20%28Full%20Report%29.pdf

[369] Department of Energy (DOE), *Transforming the Nation's Electricity System: The Second Installment of the Quadrennial Energy Review* (Washington, DC: DOE, January 2017), Fig. A-9, https://www.energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review--Second%20Installment%20%28Full%20Report%29.pdf.

[370] Federal Energy Regulatory Commission (FERC)*, Energy Primer: A Handbook of Energy Market Basics* (Washington, DC: FERC, November 2015), https://ferc.gov/market-oversight/guide/energy-primer.pdf.

[371] Midcontinent Independent System Operator, "2016 Value Proposition: Stakeholder Review Meeting" (presented on February 2017), Slide 5, https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/Workshops%20and%20Special%20Meetings/2017/Value%20Proposition/2016%20Value%20Proposition%20Presentation.pdf.

[372] Tony Clark, *Regulation and Markets: Ideas for Solving the Identity Crisis* (Washington, DC: Wilkinson Barker Knauer, July 2017), http://www.wbklaw.com/uploads/file/Articles-%20News/2017%20articles%20publications/Market%20Identity%20Crisis%20Final%20(7-14-17).pdf.

[373] Federal Energy Regulatory Commission (FERC), *Staff Analysis of Shortage Pricing in RTO and ISO Markets* (Washington, DC: FERC, October 2014), Docket No. AD14-14-000, https://www.ferc.gov/legal/staff-reports/2014/AD14-14-pricing-rto-iso-markets.pdf.

[374] Federal Energy Regulatory Commission (FERC), "Procedures for utilities requesting termination of obligation to purchase from qualifying facilities, " 18 C.F.R. § 312 – 313, https://www.ecfr.gov/cgi-bin/text-idx?c=ecfr&sid=5f16b3cdb9bef3509dc795c32a3fa674&rgn=div6&view=text&node=18:1.0.1.11.58.3&idno=18#se18.1.292_1310.

[375] Federal Energy Regulatory Commission, "Implementation Issues under the Public Utility Regulatory Policies Act of 1978 (Docket No. AD16-16-000)" (FERC Technical Conference, June 29, 2016), https://www.ferc.gov/EventCalendar/EventDetails.aspx?ID=8242&CalType=&CalendarID=116&Date=06/29/2016&View=Listview.

[376] D. B. Patton (Independent Market Monitor for The New York Independent System Operator), written statement submitted to the Federal Energy Regulatory Commission, "Joint Technical Conference on New York Markets & Infrastructure (Docket AD14-18-000)," https://www.ferc.gov/CalendarFiles/20141119133149-D%20Patton%20Written%20Statement_11-5-14.pdf.

[377] William Hogan, Harvard University, *On An "Energy Only" Electricity Market Design For Resource Adequacy*, September 23, 2005, https://sites.hks.harvard.edu/fs/whogan/Hogan_Energy_Only_092305.pdf

[378] Federal Energy Regulatory Commission (FERC), *Staff Analysis of Shortage Pricing in RTO and ISO Markets* (Washington, DC: FERC, October 2014), Docket No. AD14-14-000, https://www.ferc.gov/legal/staff-reports/2014/AD14-14-pricing-rto-iso-markets.pdf.

[379] Federal Energy Regulatory Commission (FERC), *Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators, Docket No. RM16-5-000; Order No. 831* (Washington, DC: FERC, November 17, 2016), https://www.ferc.gov/whats-new/comm-meet/2016/111716/E-2.pdf.

[380] Rich Heidorn, Jr., "Lawyers Take an Economics Class: Capacity Markets vs. Scarcity Pricing," *RTO Insider*, June 13, 2016, https://www.rtoinsider.com/capacity-markets-vs-scarcity-pricing-27702/.

[381] Rich Heidorn, Jr., "Lawyers Take an Economics Class: Capacity Markets vs. Scarcity Pricing," *RTO Insider*, June 13, 2016, https://www.rtoinsider.com/capacity-markets-vs-scarcity-pricing-27702/.

[382] K. Spees, S. Newell, and J. Pfeifenberger, "Capacity Markets—Lessons Learned from the First Decade," *Economics of Energy & Environmental Policy* 2, no. 2 (2013): 26, doi: 10.5547/2160-5890.2.2.1.

[383] K. Spees, S. Newell, and J. Pfeifenberger, "Capacity Markets—Lessons Learned from the First Decade," *Economics of Energy & Environmental Policy* 2, no. 2 (2013): 26, doi: 10.5547/2160-5890.2.2.1.

[384] Hung-po Chao, "Economics Behind Capacity Construct," PJM Interconnection, March 2017, slide 6, http://www.pjm.com/-/media/committees-groups/task-forces/ccppstf/20170306/20170306-item-06-economics-behind-capacity-construct.ashx.

[385] Monitoring Analytics, LLC, *2016 State of the Market Report for PJM* (Monitoring Analytics, LLC, March 2017), 279–80, http://www.monitoringanalytics.com/reports/pjm_state_of_the_market/2016.shtml.

[386] Severin Borenstein, "Electricity Markets and Missing Money," *The Energy Collective* (blog), April 4, 2017, http://www.theenergycollective.com/severinborenstein/2401671/electricity-markets-missing-money.

[387] Department of Energy (DOE), *Transforming the Nation's Electricity System: The Second Installment of the Quadrennial Energy Review* (Washington, DC: DOE, January 2017), 4-9, https://www.energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review--Second%20Installment%20%28Full%20Report%29.pdf.

[388] Monitoring Analytics, LLC, *2017 Quarterly State of the Market for PJM: January through March 2017* (Monitoring Analytics, May 2017), 98, http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2017/2017q1-som-pjm.pdf.

[389] Tyler Hodge, "Average Utilization for Natural Gas Combined-Cycle Plants Exceeded Coal Plants in 2015," *Today in Energy,* Energy Information Administration, April 4, 2016, https://www.eia.gov/todayinenergy/detail.php?id=25652.

[390] Ryan Wiser, Andrew Mills, et al., *Impacts of Variable Renewable Energy on Bulk Power System Assets, Pricing and Costs*, June 2017 draft (Lawrence Berkeley National Laboratory, forthcoming).

[391] PJM Interconnection, "PJM Provides the Following Documents and Information for the Department's Consideration as It Prepares Its Report in Response to the Secretary's Memorandum of April 14, 2017," sent by PJM Interconnection to the Department of Energy, May 3, 2017.

[392] "Negative Prices in Wholesale Markets Indicate Supply Inflexibilities," *Today in Energy*, Energy Information Administration, February 23, 2012, https://www.eia.gov/todayinenergy/detail.php?id=5110.

[393]PJM Interconnection, "PJM Provides the Following Documents and Information for the Department's Consideration as It Prepares Its Report in Response to the Secretary's Memorandum of April 14, 2017," sent by PJM Interconnection to the Department of Energy, May 3, 2017.

[394] Potomac Economics, *2016 State of the Market Report for the ERCOT Electricity Markets* (Fairfax, VA: Potomac Economics, May 2017), i, https://www.potomaceconomics.com/wp-content/uploads/2017/06/2016-ERCOT-State-of-the-Market-Report.pdf.

[395] William W. Hogan and Susan L. Pope, *Priorities for the Evolution of an Energy-Only Electricity Market Design in ERCOT* (FTI Consulting, 2017), https://sites.hks.harvard.edu/fs/whogan/Hogan_Pope_ERCOT_050917.pdf.

[396] Ryan Wiser, Andrew Mills, et al., *Impacts of Variable Renewable Energy on Bulk Power System Assets, Pricing and Costs*, June 2017 draft (Berkeley, CA: Lawrence Berkeley National Laboratory, forthcoming).

[397] Robert Mullin, "Spring Oversupply Lifts CAISO Curtailments," *RTO Insider,* April 24, 2017, https://www.rtoinsider.com/caiso-duck-curve-curtailments-42004/.

[398] "Negative Prices in Wholesale Markets Indicate Supply Inflexibilities," *Today in Energy*, Energy Information Administration, February 23, 2012, https://www.eia.gov/todayinenergy/detail.php?id=5110.

[399] Roy Shanker (independent consultant), "State Policies and Wholesale Markets Operated by ISO New England Inc., New York Independent System Operator, Inc., and PJM Interconnection, L.L.C. (Docket No. AD17-11-000)" (written statement submitted to the Federal Energy Regulatory Commission, Technical Conference, May 1–2, 2017), https://www.ferc.gov/CalendarFiles/20170426151725-Shanker,%20Consultant.pdf.

[400] William Hogan (Harvard University), "State Policies and Wholesale Markets Operated by ISO New England Inc., New York Independent System Operator, Inc., and PJM Interconnection, L.L.C. (Docket No. AD17-11-000)" (written statement submitted to the Federal Energy Regulatory Commission, Technical Conference, May 1–2, 2017), https://www.ferc.gov/CalendarFiles/20170426151558-Hogan,%20Harvard.pdf.

[401] Susan Tierney, Analysis Group, "State Policies and Wholesale Markets Operated by ISO New England Inc., New York Independent System Operator, Inc., and PJM Interconnection, L.L.C. (Docket No. AD17-11-000)" (written statement submitted to the Federal Energy Regulatory Commission, Technical Conference, May 1–2, 2017), https://www.ferc.gov/CalendarFiles/20170426151811-Tierney,%20Analysis%20Group.pdf.

[402] Cliff Hamel (Navigant Economics), "State Policies and Wholesale Markets Operated by ISO New England Inc., New York Independent System Operator, Inc., and PJM Interconnection, L.L.C. (Docket No. AD17-11-000)" (written statement submitted to the Federal Energy Regulatory Commission Technical Conference, May 1–2, 2017, https://www.ferc.gov/CalendarFiles/20170426151541-Hamal,%20Navigant.pdf.

[403] Samuel Newell (The Brattle Group), "State Policies and Wholesale Markets Operated by ISO New England Inc., New York Independent System Operator, Inc., and PJM Interconnection, L.L.C. (Docket No. AD17-11-000)" (written statement

submitted to the Federal Energy Regulatory Commission, Technical Conference, May 1–2, 2017), https://www.ferc.gov/CalendarFiles/20170426151703-Newell,%20The%20Brattle%20Group.pdf.

[404] Lawrence Makovich (IHS Markit), "State Policies and Wholesale Markets Operated by ISO New England Inc., New York Independent System Operator, Inc., and PJM Interconnection, L.L.C. (Docket No. AD17-11-000)" (written statement submitted to the Federal Energy Regulatory Commission, Technical Conference, May 1–2, 2017), https://www.ferc.gov/CalendarFiles/20170426151642-Makovich,%20IHS%20Markit.pdf.

[405] Jeffrey Bentz, (New England States Committee on Electricity), transcript for FERC "State Policies and Wholesale Markets Operated by ISO New England Inc., New York Independent System Operator, Inc., and PJM Interconnection, L.L.C. (Docket No. AD17-11-000)," Technical Conference, May 1, 2017, 40, https://www.ferc.gov/CalendarFiles/20170530122035-Transcript,%20May%201,%202017.pdf

[406] Angela O'Connor, (Chairman, Department of Public Utilities of Massachusetts), transcript for FERC "State Policies and Wholesale Markets Operated by ISO New England Inc., New York Independent System Operator, Inc., and PJM Interconnection, L.L.C. (Docket No. AD17-11-000)," Technical Conference, May 1, 2017, https://www.ferc.gov/CalendarFiles/20170530122035-Transcript,%20May%201,%202017.pdf.

[407] Sarah Hofmann, (Board Member, Vermont Public Service Board, speaking on behalf of the National Council on Electricity Policy), written statement submitted for FERC "State Policies and Wholesale Markets Operated by ISO New England Inc., New York Independent System Operator, Inc., and PJM Interconnection, L.L.C. (Docket No. AD17-11-000)," Technical Conference, May 1-2, 2017), https://www.ferc.gov/CalendarFiles/20170426145922-Hofmann,%20Vermont%20Public%20Service%20Board.pdf.

[408] Tony Clark, *Regulation and Markets: Ideas for Solving the Identity Crisis* (Washington, DC: Wilkinson Barker Knauer, July 2017), http://www.wbklaw.com/uploads/file/Articles-%20News/2017%20articles%20publications/Market%20Identity%20Crisis%20Final%20(7-14-17).pdf.

[409] Federal Energy Regulatory Commission (FERC), "Order on [ISO-NE] Tariff Filing and Instituting Section 206 Proceeding (Dockets Nos. ER14-1050-000, ER14-1050-001, and EL14-52-000)," May 30, 2014, https://www.iso-ne.com/regulatory/ferc/orders/2014/may/er14-1050-000_5-30-14_pay_for_performance_order.pdf

[410] Federal Energy Regulatory Commission (FERC), "Order on Proposed [PJM] Tariff Revisions (Dockets Nos. ER15-623, ER15-623-000, EL15-29-000, ER15-623-001, EL15-41-000)," June 9, 2015, https://elibrary.ferc.gov/idmws/File_list.asp?document_id=14346363

[411] Department of Energy (DOE), *Grid Modernization Multi-Year Program Plan* (Washington, DC: DOE, November 2015), 5, https://energy.gov/sites/prod/files/2016/01/f28/Grid%20Modernization%20Multi-Year%20Program%20Plan.pdf.

[412] Department of Health and Human Services (HHS), *LIHEAP Home Energy Notebook for Fiscal Year 2011* (Washington, DC: HHS, June 2014), 88, https://www.acf.hhs.gov/sites/default/files/ocs/fy2011_hen_final.pdf.

[413] Ariel Drehobl and Lauren Ross, *Lifting the High Energy Burden in America's Largest Cities: How Energy Efficiency Can Improve Low Income and Underserved Communities* (Washington, DC: American Council for an Energy-Efficient Economy, April 2016), 8, http://energyefficiencyforall.org/sites/default/files/Lifting%20the%20High%20Energy%20Burden_0.pdf.

[414] Department of Health and Human Services (HHS), "Table 2-1a. Residential Energy: Average Annual Household Consumption, Expenditures, and Burden by All Households, by Main Heating Fuel Type, United States, FY 2011," in *LIHEAP Home Energy Notebook for Fiscal Year 2011* (Washington, DC: HHS, June 2014), 4, https://www.acf.hhs.gov/sites/default/files/ocs/fy2011_hen_final.pdf.

[415] Department of Health and Human Services (HHS), "Table 2-1c. Residential Energy: Average Annual Household Consumption, Expenditures, and Burden by Low Income Households, by Main Heating Fuel Type, United States, FY 2011," in *LIHEAP Home Energy Notebook for Fiscal Year 2011* (Washington, DC: HHS, June 2014), 4, https://www.acf.hhs.gov/sites/default/files/ocs/fy2011_hen_final.pdf.

[416] Ariel Drehobl and Lauren Ross, "Lifting the High Energy Burden in America's Largest Cities: How Energy Efficiency Can Improve Low-Income and Underserved Communities," April 2016, http://aceee.org/research-report/u1602.

[417] Jayanta Bhattacharya, Thomas DeLeire, Steven Haider, and Janet Currie, "Heat or Eat? Cold-Weather Shocks and Nutrition in Poor American Families," *American Journal of Public Health* 93, no. 7 (2003): 1153, doi:10.2105/AJPH.93.7.1149.

[418] "Special Medical Needs," Hawaiian Electric Company, accessed August 1, 2017, https://www.hawaiianelectric.com/my-account/energy-assist-programs/special-medical-needs.

[419] Google, "Data center locations," Accessed August 2017, https://www.google.com/about/datacenters/inside/locations/index.html.

[420] Penny Jones, "Energy Prices Likely to Predict Key Data Center Market Moves, Analyst Says," Datacenter Dynamics, March 2013, http://www.datacenterdynamics.com/news/energy-prices-likely-to-predict-key-data-center-market-moves-analyst-says/74618.fullarticle

[421] U.S. Energy Information Administration, "Rankings: Average Retail Price of Electricity to Residential Sector, May 2017," Accessed August 2017, https://www.eia.gov/state/rankings/#/series/31

[422] Natural Resources Defense Council, "Data Center Efficiency Assessment: Scaling Up Energy Efficiency Across the Data Center Industry; Evaluating Key Drivers and Barriers," August 2014, https://www.nrdc.org/sites/default/files/data-center-efficiency-assessment-IP.pdf.

[423] "Corporate Renewable Deals, 2012–2017," Rocky Mountain Institute Business Renewables Center, June 2017, http://businessrenewables.org/corporate-transactions/.

[424] "Factors Affecting Electricity Prices," Energy Information Administration, May 2017, https://www.eia.gov/energyexplained/index.cfm/index.cfm?page=electricity_factors_affecting_prices.

[425] M. Tyson Brown and Marc Harnish, "Many Industrial Electricity Customers Are Farmers," *Today in Energy*, Energy Information Administration, May 2014, https://www.eia.gov/todayinenergy/detail.php?id=16231.

[426] Joshua D. Rhodes, Carey W. King, Gurcan Gulen, Sheila M. Olmstead, James S. Dyer, Robert E. Hebner, Fred C. Beach, Thomas F. Edgar, and Michael E. Webber, "The Full Cost of Electricity: New U.S. Power Costs: by County, with Environmental Externalities," July 2016, Page 11, https://energy.utexas.edu/files/2016/09/UTAustin_FCe_LCOE_2016-A.pdf.

[427] U.S. Energy Information Administration, "Electricity Explained: Factors Affecting Electricity Prices." https://www.eia.gov/energyexplained/index.cfm?page=electricity_factors_affecting_prices

[428] Bonbright, James C., "Principles of Public Utility Ratemaking: Chapter VI Competitive Price as a Norm of Rate Regulation," (New York: Columbia University Press, 1961), Reprinted with Permission by Powell Goldstein LLP 2005, http://media.terry.uga.edu/documents/exec_ed/bonbright/principles_of_public_utility_rates.pdf.

[429] U.S. Energy Information Administration, "Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2017," April 2017, https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf

[430] Dave Lamont and John Gerhard, "The Treatment of Energy Efficiency in Integrated Resource Plans," Regulatory Assistance Project, January 2013, http://www.raponline.org/wp-content/uploads/2016/05/rap-lamont-gerhard-treatementofeeinirp-2013-jan-28.pdf.

[431] Harvey Averch and Leland L. Johnson, "Behavior of the Firm Under Regulatory Constraint," The American Economic Review, Vol. 52, No. 5, December 1962, https://www.jstor.org/stable/pdf/1812181.pdf.

[432] Oliver Grawe, "Intra-firm Subsidization and Regulation: Do Profits Cover Losses, or Do Losses Justify Profits, and Does It Matter?," Federal Trade Commission Bureau of Economics, June 1983, https://www.ftc.gov/system/files/documents/reports/intra-firm-subsidization-regulation-do-profits-cover-losses-or-do-losses-justify-profits-does-it/wp091.pdf.

[433] New England Independent System Operator, "Wholesale vs. Retail Electricity Costs," Accessed August 2017, https://www.iso-ne.com/about/what-we-do/in-depth/wholesale-vs-retail-electricity-costs.

[434] New York Independent System Operator, "Impact of Wholesale Prices on Consumer Bills," Accessed August 2017, https://home.nyiso.com/how-wholesale-prices-factor-in-end-use-consumer-bills/.

[435] Regulatory Assistance Project, "Electricity Regulation in the US: A Guide," June 2016, Pages 68-76, 102-105, http://www.raponline.org/wp-content/uploads/2016/07/rap-lazar-electricity-regulation-US-june-2016.pdf.

[436] G. Barbose, L. Bird, J. Heeter, F. Flores, and R. Wiser, *Costs and Benefits of Renewables Portfolio Standards in the United* States (Berkeley, CA: Lawrence Berkeley National Laboratory, July 2015), LBNL-187516, https://emp.lbl.gov/sites/default/files/lbnl-187516.pdf.

[437] WM Warwick, TD Hardy, MG Hoffman, and JS Homer, "Electricity Distribution System Baseline Report Chapter 3.0 Toward a 21st Century Utility," July 2016, https://www.energy.gov/sites/prod/files/2017/01/f34/Electricity%20Distribution%20System%20Baseline%20Report.pdf

[438] Ryan H. Wiser, Galen L. Barbose, and Mark Bolinger, *Retail Rate Impacts of Renewable Electricity: Some First Thoughts* (Berkeley, CA: Lawrence Berkeley National Laboratory, March 2017), https://emp.lbl.gov/publications/retail-rate-impacts-renewable.

[439] Energy Information Administration, "Annual Average Residential Electricity Price," in *Short-Term Energy Outlook* (Washington, DC: EIA, July 2017), https://www.eia.gov/outlooks/steo/realprices/.

[440] Energy Information Administration (EIA), "Short-Term Energy Outlook, Annual Average Residential Electricity Price," in *Short-Term Energy Outlook* (Washington, DC: EIA, July 2017), https://www.eia.gov/outlooks/steo/realprices/.

[441] "2015 Total Electric Industry, Average Retail Price (cents/kWh)," Energy Information Administration, accessed August 4, 2017, https://www.eia.gov/electricity/sales_revenue_price/pdf/table4.pdf.

[442] "Table 6: 2015 Utility Bundled Retail Sales – Residential," Energy Information Administration, https://www.eia.gov/electricity/data.php#sales.

[443] "Rankings: Average Retail Price of Electricity to Residential Sector, March 2017 (cents/kWh)," Energy Information Administration, accessed August 4 2017, https://www.eia.gov/state/rankings/?sid=US#/series/31.

[444] Energy Information Administration (EIA), *Capital Cost Estimates for Utility Scale Electricity Generating Plants* (Washington, DC: EIA, November 2016), 7, https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capcost_assumption.pdf.

[445] "Form EIA-860m: Preliminary Monthly Electric Generator Inventory" Energy Information Administration, March 2017, https://www.eia.gov/electricity/data/eia860m/.

[446] S&P Global Intelligence, obtained by DOE using their database of electricity spot prices and Intercontinental Exchange natural gas spot prices taken from ABB's Energy Velocity Suite.

[447] Federal Energy Regulatory Commission (FERC), *2016 State of the Markets Report* (Washington, DC: FERC, April 2017), 13, https://www.ferc.gov/market-oversight/reports-analyses/st-mkt-ovr/2016-som.pdf.

[448] Federal Energy Regulatory Commission (FERC), *2016 State of the Markets Report* (Washington, DC: FERC, April 2017), 13, https://www.ferc.gov/market-oversight/reports-analyses/st-mkt-ovr/2016-som.pdf.

[449] J. Bushnell, E. Mansur, and K. Novan, *Review of the Economics Literature on U.S. Electric Restructuring*, April 2016 draft (Department of Energy, forthcoming).

[450] Energy Information Administration (EIA), *Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2017* (Washington, DC: EIA, April, 2017), 8, https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf.

[451] G. Barbose, L. Bird, J. Heeter, F. Flores, and R. Wiser, *Costs and Benefits of Renewables Portfolio Standards in the United* States (Berkeley, CA: Lawrence Berkeley National Laboratory, July 2015), LBNL-187516, https://emp.lbl.gov/sites/default/files/lbnl-187516.pdf.

[452] Juan Andrade and Ross Baldick, "The Full Cost of Electricity: Estimation of Transmission Costs for New Generation," September 2016, https://energy.utexas.edu/files/2016/11/UTAustin_FCe_TransmissionCosts_2016.pdf.

[453] Jaquelin Cochran, "Session 3: Impact on U.S. Ancillary Services Markets from Variable Renewable Energy," April 2013, https://www.nrel.gov/docs/fy13osti/58553.pdf

[454] Edison Electric Institute, "Transmission Projects: At A Glance," Page v, December, 2016, http://www.eei.org/issuesandpolicy/transmission/Documents/Trans_Project_lowres_bookmarked.pdf.

[455] SNL Financial, "Length of Transmission Lines (miles)," Analysis of FERC Form 1: Electric Utility Annual Report data, subscription service www.snl.com

[456] U.S. Department of Energy, "Renewable Electricity Production Tax Credit (PTC)," Accessed August 2017, https://energy.gov/savings/renewable-electricity-production-tax-credit-ptc.

[457] U.S. Department of Energy, "Business Energy Investment Tax Credit (ITC)," Accessed August 2017, https://energy.gov/savings/business-energy-investment-tax-credit-itc.

[458] Trieu Mai, Wesley Cole, Eric Lantz, Cara Marcy, and Benjamin Sigrin, "Impacts of Federal Tax Credit Extensions on Renewable Deployment and Power Sector Emissions," February 2016, https://www.nrel.gov/docs/fy16osti/65571.pdf

[459] Chris Nelder, "Congress Just Extended the PTC and ITC: What You Need to Know," Rocky Mountain Institute, January 2015, https://www.rmi.org/news/congress-just-extended-ptc-itc-need-know/

[460] Midcontinent Independent System Operator, "MISO Transmission Cost Allocation Overview," October 2013, https://www.misoenergy.org/Library/Repository/Communication%20Material/Key%20Presentations%20and%20Whitepapers/Transmission%20Cost%20Allocation%20Overview.pdf

[461] William W. Hogan, "Transmission Benefits and Cost Allocation," May 2011, https://sites.hks.harvard.edu/fs/whogan/Hogan_Trans_Cost_053111.pdf.

[462] Energy Reliability Council of Texas, "Analysis of Transmission Alternatives for Competitive Renewable Energy Zones in Texas," December 2006, http://www.ercot.com/content/news/presentations/2006/ATTCH_A_CREZ_Analysis_Report.pdf

[463] Jeffrey S. Dennis, Federal Energy Regulatory Commission (FERC), "Transmission Cost Allocation and 'Beneficiary Pays,'" January 2015, International Energy Agency ESAP and CEER Expert Workshop IV, https://www.iea.org/media/workshops/2015/esapworkshopiv/Dennis.pdf.

[464] Jess Jiang, "The Price of Electricity In Your State," *National Public Radio,* October 28, 2011. Accessed August, 2017. http://www.npr.org/sections/money/2011/10/27/141766341/the-price-of-electricity-in-your-state

[465] Robert Fares, "The U.S. Electric Grid's Cost in 2 Charts," Scientific American, April 5, 2017. Accessed August, 2017. https://blogs.scientificamerican.com/plugged-in/the-u-s-electric-grids-cost-in-2-charts/

[466] Galen Barbose, *Putting the Potential Rate Impacts of Distributed Solar into Context* (Berkeley, CA: Lawrence Berkeley National Laboratory, Energy Analysis and Impacts Division, January 2017), LBNL-1007060, https://emp.lbl.gov/sites/default/files/lbnl-1007060.pdf.

[467] PJM Interconnection, *Energy Price Formation and Valuing Flexibility* (PJM Interconnection, June 2017), http://www.pjm.com/~/media/library/reports-notices/special-reports/20170615-energy-market-price-formation.ashx.

[468] Midcontinent Independent System Operator Energy, "Extended Locational Marginal Pricing (ELMP)," November 2011, https://www.misoenergy.org/Library/Repository/Communication%20Material/Strategic%20Initiatives/ELMP%20FAQs.pdf.

[469] PJM Interconnection, *PJM's Evolving Resource Mix and System Reliability* (PJM Interconnection, March 2017), 6, http://www.pjm.com/~/media/library/reports-notices/special-reports/20170330-pjms-evolving-resource-mix-and-system-reliability.ashx.

[470] Energy Information Administration (EIA), *Direct Federal Financial Interventions and Subsidies in Energy in Fiscal Year 2013* (Washington, DC: EIA, March 2015), xix, https://www.eia.gov/analysis/requests/subsidy/pdf/subsidy.pdf.

[471] Lawrence Berkeley National Laboratory, internal analysis for the Department of Energy, June 2017.

[472] N. Kumar, P. Besuner, S. Lefton, D. Agan, and D. Hilleman, *Power Plant Cycling Costs* (Golden, CO: National Renewable Energy Laboratory, April 2012), iv, http://www.nrel.gov/docs/fy12osti/55433.pdf.

[473] The National Coal Council, *Reliable & Resilient, The Value of Our Existing Coal Fleet: An Assessment of Measures to Improve Reliability and Efficiency While Reducing Emissions* (Washington, DC: National Coal Council, May 2014), 3, http://www.nationalcoalcouncil.org/reports/1407/NCCValueExistingCoalFleet.pdf.

[474] N. Kumar, P. Besuner, S. Lefton, D. Agan, and D. Hilleman, *Power Plant Cycling Costs* (Golden, CO: National Renewable Energy Laboratory, April 2012), iv, http://www.nrel.gov/docs/fy12osti/55433.pdf.

[475] N. Kumar, P. Besuner, S. Lefton, D. Agan, and D. Hilleman, *Power Plant Cycling Costs* (Golden, CO: National Renewable Energy Laboratory, April 2012), iv, http://www.nrel.gov/docs/fy12osti/55433.pdf.

[476] Steven A. Lefton and Douglas Hilleman, "Make Your Plant Ready for Cycling Operations," *Power Magazine*, August 1, 2011, http://www.powermag.com/make-your-plant-ready-for-cycling-operations/.

[477] Nikhil Kumar, "Should You Care about Power Plant Cycling?," *Intertek* (blog), http://www.intertek.com/blog/2012-12-26-power-plant-cycling/.

[478] Electric Power Research Institute (EPRI), *Fossil Fleet Transition with Fuel Changes and Large Scale Variable Renewable Integration* (Palo Alto, CA: EPRI, March 2015), https://www.epri.com/#/pages/product/000000003002006517/.

[479] The National Coal Council, *Reliable & Resilient, The Value of Our Existing Coal Fleet: An Assessment of Measures to Improve Reliability and Efficiency While Reducing Emissions* (Washington, DC: National Coal Council, May 2014), 3, http://www.nationalcoalcouncil.org/reports/1407/NCCValueExistingCoalFleet.pdf.

[480] Debra Lew, "Coal/Gas Plant Cycling: Costs, Causes, Impacts" (presented at Harvard Electricity Policy Group, March 11, 2016), https://www.hks.harvard.edu/hepg/Papers/2016/March%202016/Lew%20Presentation.pdf.

[481] NREL, "Power Plant Cycling Costs", April 2012, Accessed August 2017, https://www.nrel.gov/docs/fy12osti/55433.pdf

[482] U.S. Nuclear Regulatory Commission, input to Department of Energy request for information, "Addressing Policy and Logistical Challenges to Smart Grid Implementation," 75 Fed. Reg. 180,57006–57011 (2010), https://www.gpo.gov/fdsys/pkg/FR-2010-09-17/html/2010-23251.htm.

[483] D. T. Ingersoll, C. Colbert, Z. Houghton, R. Snuggerud, J. W. Gaston, and M. Empey, "Integrating Nuclear and Renewables," *Nuclear Engineering International Magazine*, February 1, 2016, http://www.neimagazine.com/features/featureintegrating-nuclear-and-renewables-4795860/.

[484] Dave Schmalzer, *An Analysis of the Power Plant Cycling Phenomena*, May 29, 2017 draft (Argonne National Laboratory, forthcoming).

[485] Revis James, Stephen Hesler, and John Bistline, *Fossil Fleet Transition with Fuel Changes and Large Scale Variable Renewable Integration* (Palo Alto, CA: Electric Power Research Institute, September 2015), DOE-EPRI-OE0000614, 4-38–4-39, https://www.osti.gov/scitech/servlets/purl/1224949.

[486] Energy Information Administration (EIA): "Monthly Update to Annual Electric Generator Report," March 2017, https://www.eia.gov/electricity/data/eia860m/; and internal analysis, June 2017

Project 2016-02 Modifications to CIP Standards CIP-012-1

Ruida Shu
NPCC RSC
October 11-12, 2017

CIP-012-1 Cyber Security – Control Center Communication Networks

- **Background**
- **Key Concerns from the Industry and SDT responses**
- **Revised Requirements of CIP-012-1**
- **Revised Control Center Definition**
- **Future Actions**

Background

- CIP-012-1 Cyber Security – Control Center Communication Networks initial ballot ended on September 11, 2017.
- Quorum: 80.00%
- Approval: 42.74%

Key Concerns from the Industry 1:

- Move note to Section 4 Applicability Section
  - The SDT will look for ways to incorporate into Section 4 Applicability the information within the “Note” in the draft of CIP-012-1.
- Clarification needed around demarcation point
  - The SDT will incorporate the concept of demarcation points into the draft of CIP-012-1 in order to clarify where protection must begin and can terminate. The SDT will also include provisions allowing the entity to choose these points based on what works most effectively in the entity’s environment.

Key Concerns from the Industry 1:

- Additional Guidance Needed
  - The SDT will investigate including guidance documentation to help clarify obligations for Responsible Entities. (Guideline and Technical Basis)
- Email Communication should be Excluded
  - The SDT contends that if sensitive bulk electric system data is being transmitted via email, then those emails should be protected in some manner. Confidentiality and integrity concerns for this data exist regardless of data transmission means.

Key Concerns from the Industry 1:

- Plan not needed; adds to compliance burden; should “plan” be policy or process?
  - The SDT contends that a plan will help an entity ensure that all of the appropriate data is protected as required by draft CIP-012-1. Presenting this protection in an organized fashion, such as a plan, will not only aid compliance efforts but will also help an entity ensure that the protection employed is optimal for their environment. The SDT notes that an entity can use a pre-existing plan or plans to satisfy draft CIP-012-1 if the entity has such a plan that will satisfy the objective of CIP-012-1.

Key Concerns from the Industry 2:

- Operational Planning Analysis – Data used for Operational Planning Analysis does not have a 15 minutes impact on the reliability of the BES and should not considered sensitive BES data.
  - The SDT noted the reference in FERC Order No. 822 to additional Reliability Standards and the responsibilities to protect the data in accordance with those standards (TOP-003 and IRO-010). The SDT used these references to drive the identification of sensitive BES data and chose to base the CIP-012 requirements on the data specifications in these standards. This approach provides consistent scoping of identified data, and does not require each entity to devise its own list or inventory of this data. Many entities are required to provide this data under agreements executed with their RC, BA or TOP, often without benefit of knowing how those entities use that data..

Key Concerns from the Industry 2:

- IRO-010 & TOP-003 - Directly reference the data specification requirements in IRO-010 and TOP-003.
  - The SDT discussed referencing the two applicable standards in the requirement language and determined that a number of issues could arise by directly referencing applicable IRO/TOP requirements. Possible issues include but are not limited to applicability issues and the required coordination of future revisions of the IRO/TOP standards and CIP-012-1
- Impact of encryption on system performance – An evaluation should be performed to understand the amount of data this scope applies to and the impact of encryption on latency and computing resources. The scope may be over-reaching.
  - The SDT contends that applicable data is not used for time sensitive protection or control functions, such as communications using protocol IEC TR-61850-90-5 R-GOOSE. The SDT asserts that technical solutions are available to address the security objective of the proposed requirement without hindering operational performance

Key Concerns from the Industry 2:

- Data is different than CIP Standards - The suggested data is different from data protected in other CIP standards. This may cause confusion in the future by calling it a CIP standard.
  - The SDT noted the reference in FERC Order No. 822 to additional Reliability Standards and the responsibilities to protect the data in accordance with those standards (TOP-003-3 and IRO-010-2). The SDT used these references to drive the identification of sensitive BES data and chose to base the CIP-012 requirements on the data specifications in these standards. The SDT asserts that the data referenced by FERC Order NO. 822 is data that is used to perform Operational Planning Analysis (OPA), Real-time Assessment, and Real-time monitoring and is inherently different than BES Cyber System Information. However, the security objective to protect the confidentiality and integrity of this data, while being transmitted between Control Centers, should reside in a Critical Infrastructure Protection Standard

Key Concerns from the Industry 2:

- Encrypt the link, not the data - Technologies such as encryption or physical protection are generally implemented by link, not communication type.
  - The SDT asserts that a Responsible Entity may protect all data transmitted whether encrypting the link or the data on a communication link to achieve the security objective of this requirement
- Add "BES" - to the R1 requirement language.
  - The SDT asserts that the data required to perform OPA, RTA, or Real-time monitoring may not be limited to BES data. Please reference IRO-010-2, R1, Part 1.1, "1.1. A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data, as deemed necessary by the Reliability Coordinator"

Key Concerns from the Industry 3:

- 36 months Implementation Plan is recommended by the Industry.
  - After discussion the SDT decided to increase the Implementation period from 12 months to 24 months.

Revised Requirements of CIP-012-1:

The SDT proposed the following new language for CIP-012-1 R1 and R2:

- R1. The Responsible Entity shall develop one or more documented plan(s) to mitigate the risk of the unauthorized disclosure or modification of data, excluding oral communications, while being transmitted between any:
  - 1. A Control Center's Electronic Security Perimeter; and
  - 2. A Control Center's Cyber Assets that provide electronic across control
- R2. The Responsible Entity shall implement the plan(s) specified in Requirement R1, except under CIP Exceptional Circumstances. If multiple Responsible Entities are involved, the documented plan shall include a mutually agreed upon demarcation for inclusion in the appropriate Responsible Entities' plan.

Revised Control Center Definition:

- Existing: One or more facilities, including their associated data centers, that monitor and control the Bulk Electric System (BES) and host operating personnel who perform Real-time reliability related tasks of: 1) a Reliability Coordinator, 2) a Balancing Authority, 3) a Transmission Operator for Transmission Facilities at two or more locations, or 4) a Generator Operator for generation Facilities at two or more locations.
- Proposed: One or more facilities used by operating personnel to monitor and control the Bulk Electric System (BES) to perform the Real-time reliability-related tasks, including their associated data centers, of: 1) a Reliability Coordinator, 2) a Balancing Authority, 3) a Transmission Operator for Transmission Facilities at two or more locations, or 4) a Generator Operator for generation Facilities at two or more locations. This excludes generating plants and transmission substations.

CIP-012-1 Cyber Security – Control Center Communication Networks

- **Future Actions**
  - The SDT plans to send in updated Control Center Definition ballot request to SC in October 2017.
  - The next SDT meeting will take place the week of November 6, 2017, location is TBD.
- **Questions/Comments**

A. Introduction

1. **Title:** Transmission System Planned Performance for Geomagnetic Disturbance Events

2. **Number:** TPL-007-~~1~~2

3. **Purpose:** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Planning Coordinator with a planning area that includes a Facility or Facilities specified in 4.2;

   4.1.2 Transmission Planner with a planning area that includes a Facility or Facilities specified in 4.2;

   4.1.3 Transmission Owner who owns a Facility or Facilities specified in 4.2;

   4.1.4 Generator Owner who owns a Facility or Facilities specified in 4.2.

   4.2. Facilities:

   4.2.1 Facilities that include power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV.

5. **Background:**

   During a GMD event, geomagnetically-induced currents (GIC) may cause transformer hot-spot heating or damage, loss of Reactive Power sources, increased Reactive Power demand, and Misoperation(s), the combination of which may result in voltage collapse and blackout.

6. **Effective Date:**

   See Implementation Plan for TPL-007-~~1~~2

B. Requirements and Measures

R1. Each Planning Coordinator, in conjunction with its Transmission Planner(s), shall identify the individual and joint responsibilities of the Planning Coordinator and Transmission Planner(s) in the Planning Coordinator's planning area for maintaining models ~~and~~, performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessment~~(s)~~, and implementing process(es) to obtain GMD measurement data as specified in this standard. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M1. Each Planning Coordinator, in conjunction with its Transmission Planners, shall provide documentation on roles and responsibilities, such as meeting minutes, agreements, copies of procedures or protocols in effect between entities or between departments of a vertically integrated system, or email correspondence that identifies an agreement has been reached on individual and joint responsibilities for maintaining models ~~and~~,

performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessment~~(s)~~, and implementing process(es) to obtain GMD ~~M~~measurement ~~D~~data in accordance with Requirement R1.

R2. Each responsible entity, as determined in Requirement R1, shall maintain System models and GIC System models of the responsible entity's planning area for performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessment~~(s)~~. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M2. Each responsible entity, as determined in Requirement R1, shall have evidence in either electronic or hard copy format that it is maintaining System models and GIC System models of the responsible entity's planning area for performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessment~~(s)~~.

R3. Each responsible entity, as determined in Requirement R1, shall have criteria for acceptable System steady state voltage performance for its System during the ~~benchmark~~ GMD ~~event~~events described in Attachment 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M3. Each responsible entity, as determined in Requirement R1, shall have evidence, such as electronic or hard copies of the criteria for acceptable System steady state voltage performance for its System in accordance with Requirement R3.

Benchmark GMD Vulnerability Assessment(s)

R4. Each responsible entity, as determined in Requirement R1, shall complete a benchmark GMD Vulnerability Assessment of the Near-Term Transmission Planning Horizon at least once every 60 calendar months. This benchmark GMD Vulnerability Assessment shall use a study or studies based on models identified in Requirement R2, document assumptions, and document summarized results of the steady state analysis. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

4.1. The study or studies shall include the following conditions:

4.1.1. System On-Peak Load for at least one year within the Near-Term Transmission Planning Horizon; and

4.1.2. System Off-Peak Load for at least one year within the Near-Term Transmission Planning Horizon.

4.2. The study or studies shall be conducted based on the benchmark GMD event described in Attachment 1 to determine whether the System meets the performance requirements for the steady state planning benchmark GMD event contained in Table 1.

4.3. The benchmark GMD Vulnerability Assessment shall be provided: (i) ~~within 90 calendar days of completion~~ to the responsible entity's Reliability Coordinator,

adjacent Planning Coordinators, and adjacent Transmission Planners~~,~~ within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the benchmark GMD Vulnerability Assessment, whichever is later.

4.3.1. If a recipient of the benchmark GMD Vulnerability Assessment provides documented comments on the results, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M4. Each responsible entity, as determined in Requirement R1, shall have dated evidence such as electronic or hard copies of its benchmark GMD Vulnerability Assessment meeting all of the requirements in Requirement R4. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its benchmark GMD Vulnerability Assessment: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, and adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the benchmark GMD Vulnerability Assessment, whichever is later, ~~within 90 calendar days of completion to its Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and to any functional entity who has submitted a written request and has a reliability-related need~~ as specified in Requirement R4. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its benchmark GMD Vulnerability Assessment within 90 calendar days of receipt of those comments in accordance with Requirement R4.

R5. Each responsible entity, as determined in Requirement R1, shall provide GIC flow information to be used for the ~~transformer~~benchmark thermal impact assessment of transformers specified in Requirement R6 to each Transmission Owner and Generator Owner that owns an applicable Bulk Electric System (BES) power transformer in the planning area. The GIC flow information shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

5.1. The maximum effective GIC value for the worst case geoelectric field orientation for the benchmark GMD event described in Attachment 1. This value shall be provided to the Transmission Owner or Generator Owner that owns each applicable BES power transformer in the planning area.

5.2. The effective GIC time series, GIC(t), calculated using the benchmark GMD event described in Attachment 1 in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power

transformer in the planning area. GIC(t) shall be provided within 90 calendar days of receipt of the written request and after determination of the maximum effective GIC value in Part 5.1.

M5. Each responsible entity, as determined in Requirement R1, shall provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided the maximum effective benchmark GIC value to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area as specified in Requirement R5, Part 5.1. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided GIC(t) in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area.

R6. Each Transmission Owner and Generator Owner shall conduct a benchmark thermal impact assessment for its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A per phase or greater. The benchmark thermal impact assessment shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- **6.1.** Be based on the effective GIC flow information provided in Requirement R5;
- **6.2.** Document assumptions used in the analysis;
- **6.3.** Describe suggested actions and supporting analysis to mitigate the impact of GICs, if any; and
- **6.4.** Be performed and provided to the responsible entities, as determined in Requirement R1, within 24 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1.

M6. Each Transmission Owner and Generator Owner shall have evidence such as electronic or hard copies of its benchmark thermal impact assessment for all of its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A per phase or greater, and shall have evidence such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided its thermal impact assessment to the responsible entities as specified in Requirement R6.

Rationale for Requirement R7: The proposed requirement addresses directives in Order No. 830 for establishing Corrective Action Plan (CAP) deadlines associated with GMD Vulnerability Assessments. In Order No. 830, FERC directed revisions to TPL-007 such that CAPs are developed within one year from the completion of GMD Vulnerability Assessments (P. 101). Furthermore, FERC directed establishment of implementation deadlines after the completion of the CAP as follows (P. 102):

- Two years for non-hardware mitigation; and

- Four years for hardware mitigation.

The objective of Part 7.4 is to provide awareness to potentially impacted entities when implementation of planned mitigation is not achievable within the deadlines established in Part 7.3.

R7. Each responsible entity, as determined in Requirement R1, that concludes~~,~~ through the benchmark GMD Vulnerability Assessment conducted in Requirement R4~~,~~ that their System does not meet the performance requirements ~~of~~for the steady state planning benchmark GMD event contained in Table 1 shall develop a Corrective Action Plan (CAP) addressing how the performance requirements will be met. The ~~Corrective Action Plan~~CAP shall: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or ~~Special Protection Systems~~Remedial Action Schemes.
- Use of Operating Procedures, specifying how long they will be needed as part of the ~~Corrective Action Plan~~CAP.
- Use of Demand-Side Management, new technologies, or other initiatives.

7.2. ~~Be reviewed in subsequent GMD Vulnerability Assessments until it is determined that the System meets the performance requirements contained in Table 1.~~Be developed within one year of completion of the benchmark GMD Vulnerability Assessment.

7.3. Include a timetable, subject to revision by the responsible entity in Part 7.4, for implementing the selected actions from Part 7.1. The timetable shall:

7.3.1. Specify implementation of non-hardware mitigation, if any, within two years of development of the CAP; and

7.3.2. Specify implementation of hardware mitigation, if any, within four years of development of the CAP.

7.4. Be revised if situations beyond the control of the responsible entity determined in Requirement R1 prevent implementation of the CAP within the timetable for implementation provided in Part 7.3. The revised CAP shall document the following, and be updated at least once every 12 calendar months until implemented:

7.4.1. Circumstances causing the delay for fully or partially implementing the selected actions in Part 7.1;

7.4.2. Description of the original CAP, and any previous changes to the CAP, with the associated timetable(s) for implementing the selected actions in Part 7.1; and

7.4.3. Revisions to the selected actions in Part 7.1, if any, including utilization of Operating Procedures if applicable, and the updated timetable for implementing the selected actions.

~~7.2.~~7.5. Be provided: (i) ~~within 90 calendar days of completion~~development or ~~revision~~ to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the ~~Corrective Action Plan~~CAP within 90 calendar days of development or revision, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later.

~~7.2.1.~~7.5.1. If a recipient of the ~~Corrective Action Plan~~CAP provides documented comments on the results, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M7. Each responsible entity, as determined in Requirement R1, that concludes, through the benchmark GMD Vulnerability Assessment conducted in Requirement R4, that the responsible entity's System does not meet the performance requirements ~~of~~ for the steady state planning benchmark GMD event contained in Table 1 shall have evidence such as dated electronic or hard copies of its ~~Corrective Action Plan~~CAP including timetable for implementing selected actions, as specified in Requirement R7. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records or postal receipts showing recipient and date, that it has revised its CAP if situations beyond the responsible entity's control prevent implementation of the CAP within the timetable specified. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its ~~Corrective Action Plan~~CAP or relevant information, if any, (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later,~~within 90 calendar days of its completion~~development or revision to its Reliability Coordinator, ~~adjacent Planning Coordinator(s), adjacent Transmission Planner(s), a functional entity referenced in the Corrective Action Plan~~CAP, ~~and any functional entity that submits~~who ~~has submitted a written request and has a reliability-related need,~~ as specified in Requirement R7. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date,

that it has provided a documented response to comments received on its ~~Corrective Action Plan~~CAP within 90 calendar days of receipt of those comments, in accordance with Requirement R7.

Supplemental GMD Vulnerability Assessment(s)

Rationale for Requirements R8 - R10: The proposed requirements address directives in Order No. 830 for revising the benchmark GMD event used in GMD Vulnerability Assessments (P.44, P47-49). The requirements add a supplemental GMD Vulnerability Assessment based on the supplemental GMD event that accounts for localized peak geoelectric fields.

R8. Each responsible entity, as determined in Requirement R1, shall complete a supplemental GMD Vulnerability Assessment of the Near-Term Transmission Planning Horizon at least once every 60 calendar months. This supplemental GMD Vulnerability Assessment shall use a study or studies based on models identified in Requirement R2, document assumptions, and document summarized results of the steady state analysis. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

8.1. The study or studies shall include the following conditions:

8.1.1. System On-Peak Load for at least one year within the Near-Term Transmission Planning Horizon; and

8.1.2. System Off-Peak Load for at least one year within the Near-Term Transmission Planning Horizon.

8.2 The study or studies shall be conducted based on the supplemental GMD event described in Attachment 1 to determine whether the System meets the performance requirements for the steady state planning supplemental GMD event contained in Table 1.

8.3 If the analysis concludes there is Cascading caused by the supplemental GMD event described in Attachment 1, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

8.4 The supplemental GMD Vulnerability Assessment shall be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, and adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the supplemental GMD Vulnerability Assessment, whichever is later.

8.4.1 If a recipient of the supplemental GMD Vulnerability Assessment provides documented comments on the results, the responsible entity

shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M8. Each responsible entity, as determined in Requirement R1, shall have dated evidence such as electronic or hard copies of its supplemental GMD Vulnerability Assessment meeting all of the requirements in Requirement R8. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its supplemental GMD Vulnerability Assessment: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the supplemental GMD Vulnerability Assessment, whichever is later, as specified in Requirement R8. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its supplemental GMD Vulnerability Assessment within 90 calendar days of receipt of those comments in accordance with Requirement R8.

R9. Each responsible entity, as determined in Requirement R1, shall provide GIC flow information to be used for the supplemental thermal impact assessment of transformers specified in Requirement R10 to each Transmission Owner and Generator Owner that owns an applicable Bulk Electric System (BES) power transformer in the planning area. The GIC flow information shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

9.1. The maximum effective GIC value for the worst case geoelectric field orientation for the supplemental GMD event described in Attachment 1. This value shall be provided to the Transmission Owner or Generator Owner that owns each applicable BES power transformer in the planning area.

9.2. The effective GIC time series, GIC(t), calculated using the supplemental GMD event described in Attachment 1 in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area. GIC(t) shall be provided within 90 calendar days of receipt of the written request and after determination of the maximum effective GIC value in Part 9.1.

M9. Each responsible entity, as determined in Requirement R1, shall provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided the maximum effective supplemental GIC value to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area as specified in Requirement R9, Part 9.1. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal

receipts showing recipient and date, that it has provided GIC(t) in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area.

R10. Each Transmission Owner and Generator Owner shall conduct a supplemental thermal impact assessment for its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A per phase or greater. The supplemental thermal impact assessment shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

10.1. Be based on the effective GIC flow information provided in Requirement R9;

10.2. Document assumptions used in the analysis;

10.3. Describe suggested actions and supporting analysis to mitigate the impact of GICs, if any; and

10.4. Be performed and provided to the responsible entities, as determined in Requirement R1, within 24 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1.

M10. Each Transmission Owner and Generator Owner shall have evidence such as electronic or hard copies of its supplemental thermal impact assessment for all of its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A per phase or greater, and shall have evidence such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided its supplemental thermal impact assessment to the responsible entities as specified in Requirement R10.

GMD Measurement Data Processes

Rationale for Requirements R11 and R12: The proposed requirements address directives in Order No. 830 for requiring responsible entities to collect GIC monitoring and magnetometer data as necessary to enable model validation and situational awareness (P. 88; P. 90-92). See the Guidelines and Technical Basis section of this standard for technical information.

The objective of Requirement R11 is for entities to obtain GIC data for the Planning Coordinator's planning area or other part of the system included in the Planning Coordinator's GIC System model to inform GMD Vulnerability Assessments. Technical considerations for GIC monitoring are contained in Chapter 6 of the *2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk-Power System* (NERC 2012 GMD Report). GIC monitoring is generally performed by Hall effect transducers that are attached to the neutral of the transformer and measure dc current flowing through the neutral.

The objective of Requirement R12 is for entities to obtain geomagnetic field data for the Planning Coordinator's planning area to inform GMD Vulnerability Assessments.

Magnetometers provide geomagnetic field data by measuring changes in the earth's magnetic field. Sources of geomagnetic field data include:

- Observatories such as those operated by U.S. Geological Survey, Natural Resources Canada, research organizations, or university research facilities.
- Installed magnetometers
- Commercial or third-party sources of geomagnetic field data

Geomagnetic field data for a Planning Coordinator's planning area is obtained from one or more of the above data sources located in the Planning Coordinator's planning area, or by obtaining a geomagnetic field data product for the Planning Coordinator's planning area from a government or research organization. The geomagnetic field data product does not need to be derived from a magnetometer or observatory within the Planning Coordinator's planning area.

~~R8.~~R11. Each responsible entity, as determined in Requirement R1, shall implement a process to obtain GIC monitor data from at least one GIC monitor located in the Planning Coordinator's planning area or other part of the system included in the Planning Coordinator's GIC System model. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M11. Each responsible entity, as determined in Requirement R1, shall have evidence such as electronic or hard copies of its GIC monitor location(s) and documentation of its process to obtain GIC monitor data in accordance with Requirement R11.

~~R9.~~R12. Each responsible entity, as determined in Requirement R1, shall implement a process to obtain geomagnetic field data for its Planning Coordinator's planning area. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M12. Each responsible entity, as determined in Requirement R1, shall have evidence such as electronic or hard copies of its process to obtain geomagnetic field data for its Planning Coordinator's planning area in accordance with Requirement R12.

Table 1 – Steady State Planning GMD Event

Steady State:

a. Voltage collapse, Cascading and uncontrolled islanding shall not occur.

b. Generation loss is acceptable as a consequence of the steady state planning GMD events.

c. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Category	Initial Condition	Event	Interruption of Firm Transmission Service Allowed	Load Loss Allowed
Benchmark GMD Event - GMD Event with Outages	1. System as may be postured in response to space weather information[1], and then 2. GMD event[2]	Reactive Power compensation devices and other Transmission Facilities removed as a result of Protection System operation or Misoperation due to harmonics during the GMD event	Yes[3]	Yes[3]
Supplemental GMD Event - GMD Event with Outages	1. System as may be postured in response to space weather information[1], and then 2. GMD event[2]	Reactive Power compensation devices and other Transmission Facilities removed as a result of Protection System operation or Misoperation due to harmonics during the GMD event	Yes	Yes

Table 1 – Steady State Performance Footnotes

1. The System condition for GMD planning may include adjustments to posture the System that are executable in response to space weather information.
2. The GMD conditions for the benchmark and supplemental planning ~~event~~events are described in Attachment 1~~ (Benchmark GMD Event).~~.
3. Load loss as a result of manual or automatic Load shedding (e.g.~~,~~, UVLS) and/or curtailment of Firm Transmission Service may be used to meet BES performance requirements during studied GMD conditions. The likelihood and magnitude of Load loss or curtailment of Firm Transmission Service should be minimized.

Attachment 1

Calculating Geoelectric Fields for the Benchmark and Supplemental GMD EventEvents

The benchmark GMD event[1] defines the geoelectric field values used to compute GIC flows that are needed to conduct a benchmark GMD Vulnerability Assessment. It is composed of the following elements: (1) a reference peak geoelectric field amplitude of 8 V/km derived from statistical analysis of historical magnetometer data; (2) scaling factors to account for local geomagnetic latitude; (3) scaling factors to account for local earth conductivity; and (4) a reference geomagnetic field time series or waveshapewaveform to facilitate time-domain analysis of GMD impact on equipment.

The supplemental GMD event is composed of similar elements as described above, except (1) the reference peak geoelectric field amplitude is 12 V/km over a localized area; and (2) the geomagnetic field time series or waveform includes a local enhancement in the waveform.[2]

The regional geoelectric field peak amplitude used in GMD Vulnerability Assessment, E_{peak}, can be obtained from the reference geoelectric field value of 8 V/km for the benchmark GMD event (1) or 12 V/km for the supplemental GMD event (2) using the following relationships:

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

$$E_{peak} = 12 \times \alpha \times \beta_{\,s} \text{ (V/km)} \quad (2)$$

where α is the scaling factor to account for local geomagnetic latitude, and β is a scaling factor to account for the local earth conductivity structure. Subscripts *b* and *s* for the β scaling factor denotes association with the benchmark or supplemental GMD events, respectively.

Scaling the Geomagnetic Field

The benchmark and supplemental GMD event isevents are defined for geomagnetic latitude of 60° and it must be scaled to account for regional differences based on geomagnetic latitude. Table 2 provides a scaling factor correlating peak geoelectric field to geomagnetic latitude. Alternatively, the scaling factor α is computed with the empirical expression

$$\alpha = 0.001 \cdot e^{(0.115 \cdot L)} \quad (2)$$

[1] The benchmark GMD event description is available on the Project 2013-03 Geomagnetic Disturbance Mitigation projectRelated Information page:http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx for TPL-007-1:; http://www.nerc.com/pa/stand/Pages/TPL0071RI.aspx

[2] The extent of local enhancements is on the order of 100 km in North-South (latitude) direction but longer in East-West (longitude) direction. The local enhancement in the geomagnetic field occurs over the time period of 2-5 minutes. Additional information is available in the sSupplemental GMD eEvent dDescription white paper on the Project 2013-03 Geomagnetic Disturbance Mitigation project page: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

$$\alpha = 0.001 \cdot e^{(0.115 \cdot L)} \quad (3)$$

where L is the geomagnetic latitude in degrees and 0.1 ≤ α ≤ 1.

For large planning areas that cover more than one scaling factor from Table 2, the GMD Vulnerability Assessment should be based on a peak geoelectric field that is:

- calculated by using the most conservative (largest) value for α; or
- calculated assuming a non-uniform or piecewise uniform geomagnetic field.

Table 2– Geomagnetic Field Scaling Factors for the Benchmark and Supplemental GMD Events

Geomagnetic Latitude (Degrees)	Scaling Factor1 (α)
≤ 40	0.10
45	0.2
50	0.3
54	0.5
56	0.6
57	0.7
58	0.8
59	0.9
≥ 60	1.0

Scaling the Geoelectric Field

The benchmark GMD event is defined for the reference Quebec earth model described in Table 4. The peak geoelectric field, E_{peak}, used in a GMD Vulnerability Assessment may be obtained by either:

- Calculating the geoelectric field for the ground conductivity in the planning area and the reference geomagnetic field time series scaled according to geomagnetic latitude, using a procedure such as the plane wave method described in the NERC GMD Task Force GIC Application Guide;[3] or
- Using the earth conductivity scaling factor β from Table 3 that correlates to the ground conductivity map in Figure 1 or Figure 2. Along with the scaling factor α from equation (2 3) or Table 2, β is applied to the reference geoelectric field using equation (1 or 2, as applicable) to obtain the regional geoelectric field peak amplitude E_{peak} to be used in GMD Vulnerability Assessment Assessments. When a ground conductivity model is not

[3] Available at the NERC GMD Task Force project page: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx

available, the planning entity should use the largest β factor of adjacent physiographic regions or a technically justified value.

The earth models used to calculate Table 3 for the United States were obtained from publicly available information published on the U. S. Geological Survey website.[4] The models used to calculate Table 3 for Canada were obtained from Natural Resources Canada (NRCan) and reflect the average structure for large regions. A planner can also use specific earth model(s) with documented justification and the reference geomagnetic field time series to calculate the β factor(s) as follows:

$\beta_b = E/8$~~$\beta = E/8$~~ for the benchmark GMD event (4)

$\beta_s = E/12$ for the supplemental GMD event (5)

where *E* is the absolute value of peak geoelectric in V/km obtained from the technically justified earth model and the reference geomagnetic field time series.

For large planning areas that span more than one β scaling factor, the most conservative (largest) value for β may be used in determining the peak geoelectric field to obtain conservative results. Alternatively, a planner could perform analysis using a non-uniform or piecewise uniform geoelectric field.

Applying the Localized Peak Geoelectric Field in the Supplemental GMD Event

The peak geoelectric field of the supplemental GMD event occurs in a localized area.[5] Planners have flexibility to determine how to apply the localized peak geoelectric field over the planning area in performing GIC calculations. Examples of approaches are:

- Apply the peak geoelectric field (12 V/km scaled to the planning area) over the entire planning area;
- Apply a spatially limited (12 V/km scaled to the planning area) peak geoelectric field (e.g., 100 km in North-South latitude direction and 500 km in East-West longitude direction) over a portion(s) of the system, and apply the benchmark GMD event over the rest of the system; or
- Other methods to adjust the benchmark GMD event analysis to account for the localized geoelectric field enhancement of the supplemental GMD event.

[4] Available at http://geomag.usgs.gov/conductivity/

[5] See the Supplemental Geomagnetic Disturbance Description white paper located on the Project 2013-03 Geomagnetic Disturbance Mitigation project page: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

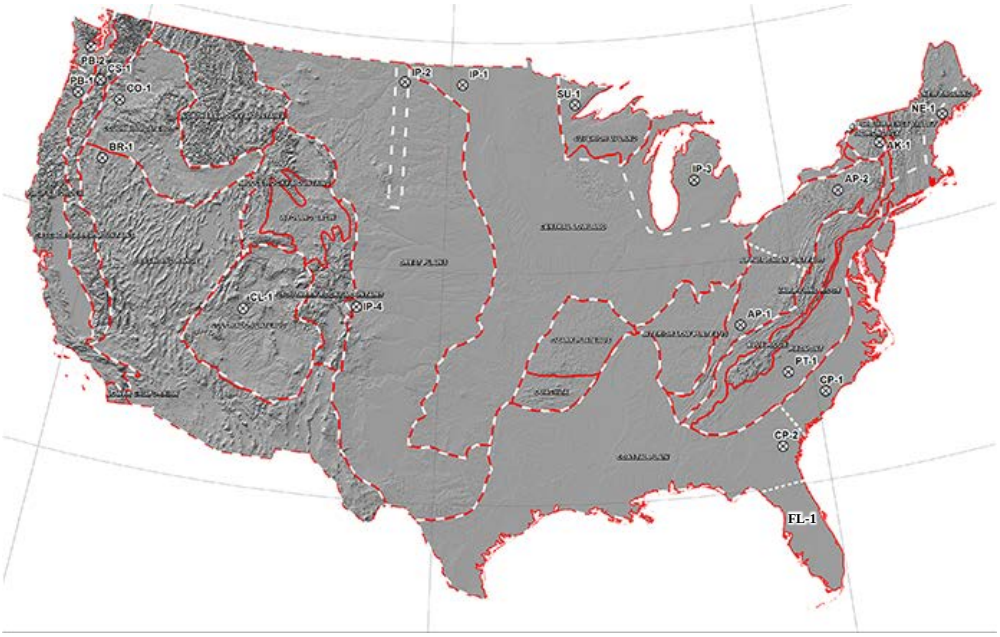


Figure 1: Physiographic Regions of the Continental United States[6]

Figure 2: Physiographic Regions of Canada

6 Additional map detail is available at the U.S. Geological Survey (http://geomag.usgs.gov/)

Table 3 – Geoelectric Field Scaling Factors		
~~USGS~~ Earth model	Scaling Factor ~~(β)~~Benchmark Event (β_b)	Scaling Factor Supplemental Event (β_s)
AK1A	0.56	0.51
AK1B	0.56	0.51
AP1	0.33	0.30
AP2	0.82	0.78
BR1	0.22	0.22
CL1	0.76	0.73
CO1	0.27	0.25
CP1	0.81	0.77
CP2	0.95	0.86
FL1	0.~~74~~76	0.73
CS1	0.41	0.37
IP1	0.94	0.90
IP2	0.28	0.25
IP3	0.93	0.90
IP4	0.41	0.35
NE1	0.81	0.77
PB1	0.62	0.55
PB2	0.46	0.39
PT1	1.17	1.19
SL1	0.53	0.49
SU1	0.93	0.90
BOU	0.28	0.24
FBK	0.56	0.56
PRU	0.21	0.22
BC	0.67	0.62
PRAIRIES	0.96	0.88
SHIELD	1.0	1.0
ATLANTIC	0.79	0.76

Rationale: Scaling factors in Table 3 are dependent upon the frequency content of the reference storm. Consequently, the benchmark GMD event and the supplemental GMD event may produce different scaling factors for a given earth model.

The scaling factor associated with the benchmark GMD event for the Florida earth model (FL-1) has been updated based on the earth model published on the USGS public website.

Table 4 – Reference Earth Model (Quebec)	
Layer Thickness (km)	Resistivity (Ω-m)
15	20,000
10	200
125	1,000
200	100
∞	3

Reference Geomagnetic Field Time Series or ~~Waveshape~~[7]Waveform for the Benchmark GMD Event[8]

The geomagnetic field measurement record of the March 13-14 1989 GMD event, measured at NRCan's Ottawa geomagnetic observatory is the basis for the reference geomagnetic field ~~waveshape~~waveform to be used to calculate the GIC time series, GIC(t), required for transformer thermal impact assessment.

The geomagnetic latitude of the Ottawa geomagnetic observatory is 55°; therefore, the amplitude of the geomagnetic field measurement data were scaled up to the 60° reference geomagnetic latitude (see Figure 3) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 8 V/km (see Figures 4 and 5). The ~~Sampling~~ sampling rate for the geomagnetic field ~~waveshape~~waveform is 10 seconds.[9] To use this geoelectric field time series when a different earth model is applicable, it should be scaled with the appropriate benchmark conductivity scaling factor ~~β~~.β_b.

~~[7] Refer to the Benchmark GMD Event Description for details on the determination of the reference geomagnetic field waveshape: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx~~

[8] Refer to the Benchmark GMD Event Description white paper for details on the determination of the reference geomagnetic field waveform: http://www.nerc.com/pa/stand/Pages/TPL0071RI.aspx

[9] The data file of the benchmark geomagnetic field ~~waveshape~~waveform is available on the ~~NERC GMD Task Force project~~Related Information page~~: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx~~ for TPL-007-1: http://www.nerc.com/pa/stand/Pages/TPL0071RI.aspx

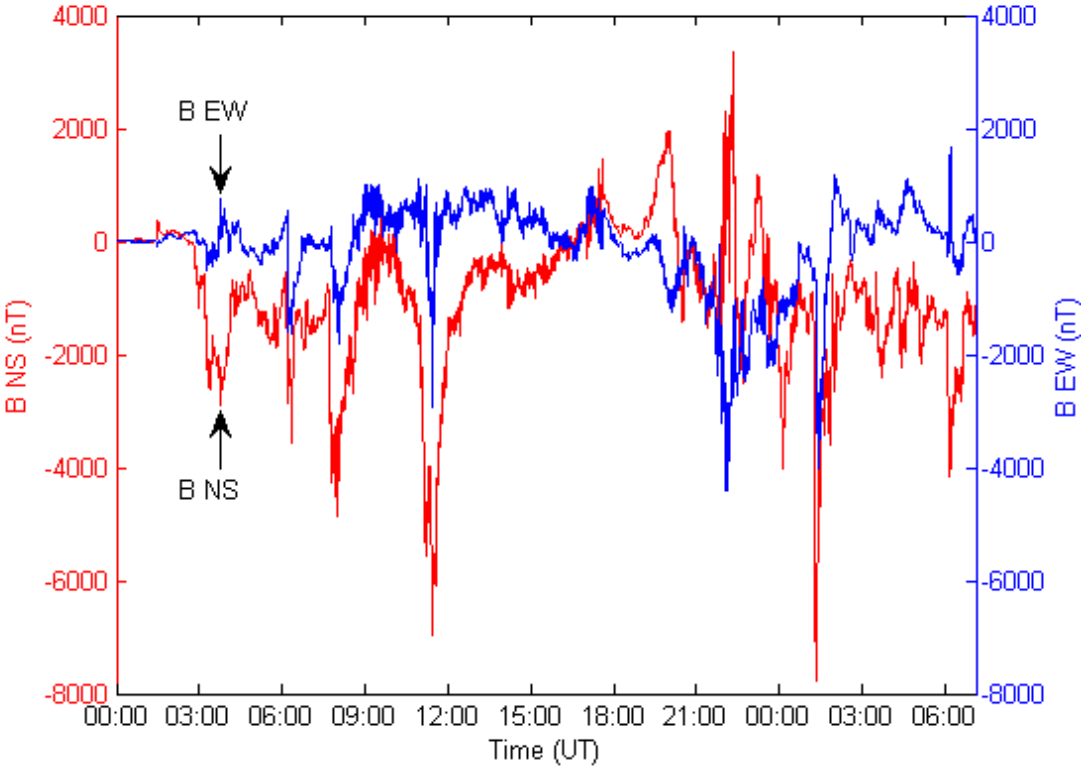


Figure 3: Benchmark Geomagnetic Field ~~Waveshape~~Waveform. Red B_n (Northward), Blue B_e (Eastward)

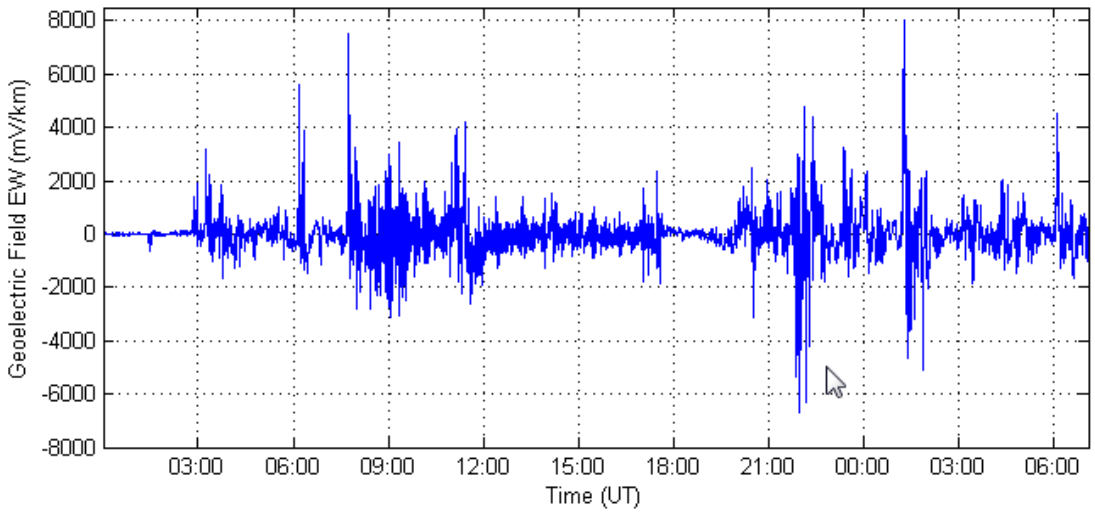


Figure 4: Benchmark Geoelectric Field ~~Waveshape~~Waveform - E_E (Eastward)

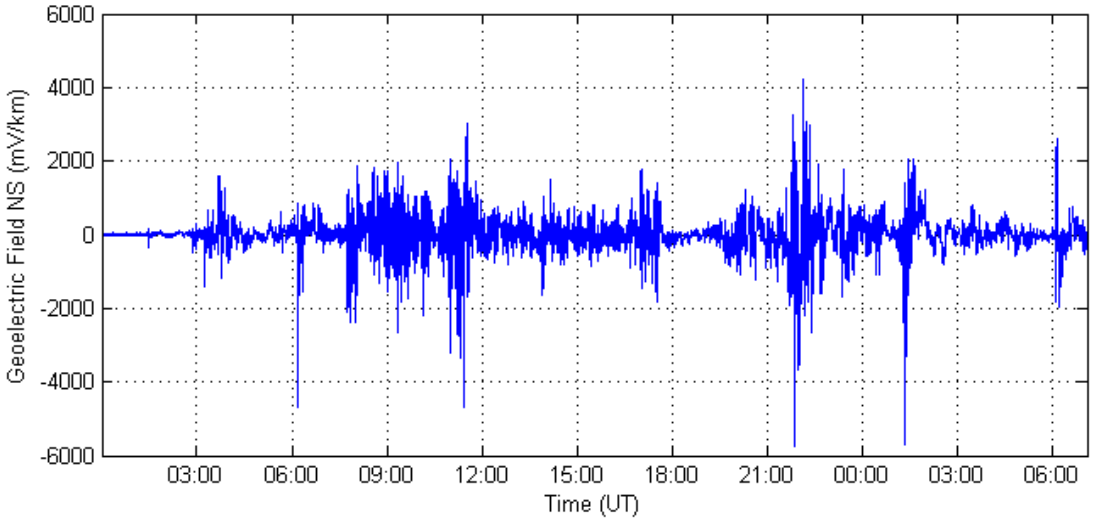


Figure 5: Benchmark Geoelectric Field ~~Waveshape~~Waveform – E_N (Northward)

Reference Geomagnetic Field Time Series or Waveform for the Supplemental GMD Event[10]

The geomagnetic field measurement record of the March 13-14, 1989 GMD event, measured at NRCan's Ottawa geomagnetic observatory is the basis for the reference geomagnetic field waveform to be used to calculate the GIC time series, GIC(t), required for transformer thermal impact assessment for the supplemental GMD event. The supplemental GMD event waveform differs from the benchmark GMD event waveform in that the supplemental GMD event waveform has a local enhancement.

The geomagnetic latitude of the Ottawa geomagnetic observatory is 55°; therefore, the amplitude of the geomagnetic field measurement data were scaled up to the 60° reference geomagnetic latitude (see Figure 6) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 12 V/km (see Figure7). The sampling rate for the geomagnetic field waveform is 10 seconds.[11] To use this geoelectric field time series when a different earth model is applicable, it should be scaled with the appropriate supplemental conductivity scaling factor β_S.

[10] Refer to the Supplemental GMD Event Description white paper for details on the determination of the reference geomagnetic field waveform: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

[11] The data file of the benchmark geomagnetic field waveform is available on the NERC GMD Task Force project page: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx

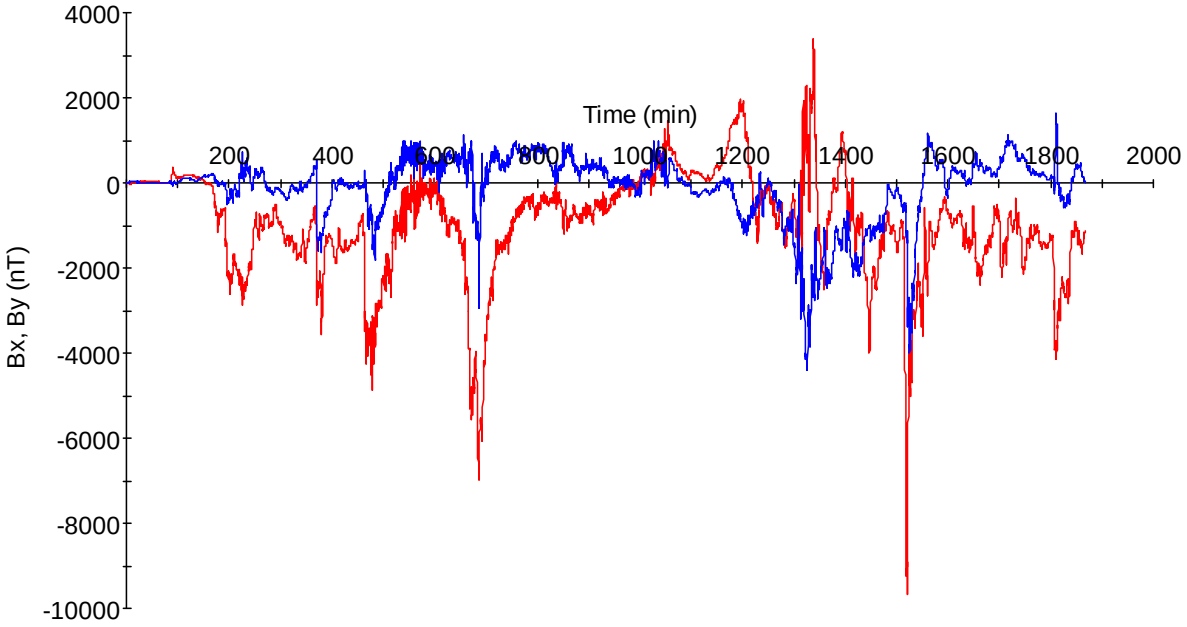


Figure 6: Supplemental Geomagnetic Field Waveform. Red B_n (Northward), Blue B_e (Eastward)

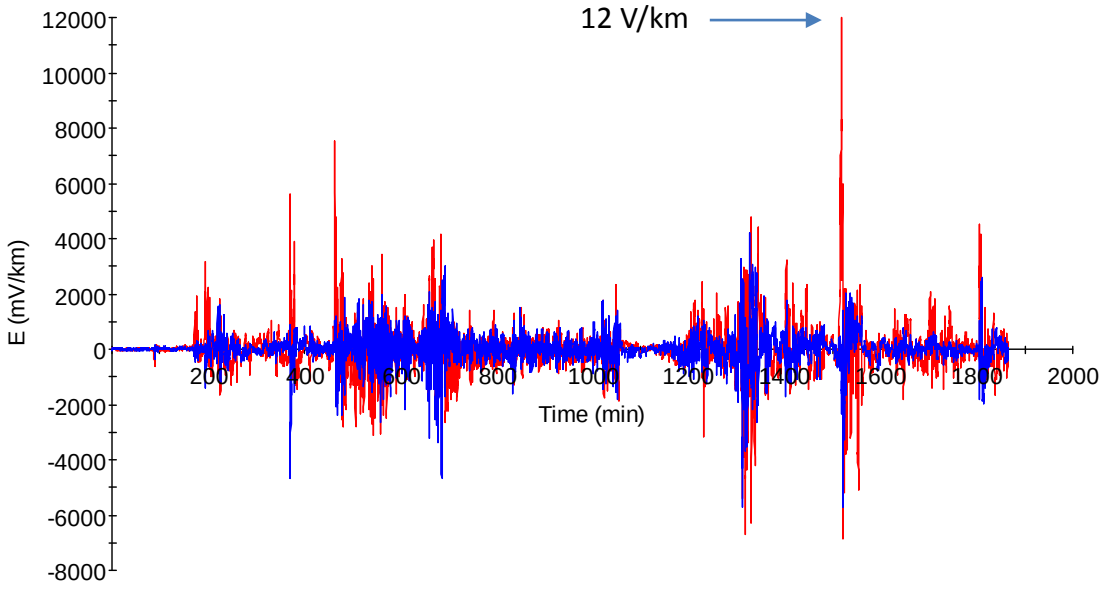


Figure 7: Supplemental Geoelectric Field Waveform. ~~Red~~ Blue E_n (Northward), ~~Blue~~ Red E_e (Eastward)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

~~As defined in the NERC Rules of Procedure,~~ "Compliance Enforcement Authority" means NERC or the Regional Entity, 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. Evidence Retention

The following evidence retention ~~periods~~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 ~~CEA~~Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

~~The Planning Coordinator, Transmission Planner, Transmission Owner, and Generator Owner~~The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation~~:~~.

- For Requirements R1, R2, R3, R5, R6, R9, and ~~R6~~R10, each responsible entity shall retain documentation as evidence for five years.
- For ~~Requirement~~Requirements R4 and R8, each responsible entity shall retain documentation of the current GMD Vulnerability Assessment and the preceding GMD Vulnerability Assessment.
- For Requirement R7, each responsible entity shall retain documentation as evidence for five years or until all actions in the Corrective Action Plan are completed, whichever is later.
- For Requirements R11 and R12, each responsible entity shall retain documentation as evidence for three years.

~~If a Planning Coordinator, Transmission Planner, Transmission Owner, or Generator Owner is found non-compliant it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.~~

~~The 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 Audits~~

~~Self-Certifications~~

~~Spot Checking~~

~~Compliance Investigations~~

~~Self-Reporting~~

~~Complaints~~

~~**1.4. Additional Compliance Information**~~

~~None~~

- For Requirements R11 and R12, each responsible entity shall retain documentation as evidence for three years.

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

Table of Compliance Elements

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	~~Long-term Planning~~	~~Lower~~	N/A	N/A	N/A	The Planning Coordinator, in conjunction with its Transmission Planner(s), failed to determine and identify individual or joint responsibilities of the Planning Coordinator and Transmission Planner(s) in the Planning Coordinator's planning area for maintaining models ~~and~~, performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessment~~(s).~~, and implementing process(es) to obtain

						GMD measurement data as specified in this standard.
R2	~~Long-term Planning~~	~~High~~	N/A	N/A	The responsible entity did not maintain either System models or GIC System models of the responsible entity's planning area for performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessment~~(s)~~.	The responsible entity did not maintain both System models and GIC System models of the responsible entity's planning area for performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessment~~(s)~~.
R3	~~Long-term Planning~~	~~Medium~~	N/A	N/A	N/A	The responsible entity did not have criteria for acceptable System steady state voltage performance for its System during the ~~benchmark~~ GMD ~~event~~events described in Attachment 1 as required.
R4	~~Long-term Planning~~	~~High~~	The responsible entity completed a benchmark GMD	The responsible entity's completed benchmark GMD	The responsible entity's completed benchmark GMD	The responsible entity's completed benchmark GMD

			Vulnerability Assessment, but it was more than 60 calendar months and less than or equal to 64 calendar months since the last benchmark GMD Vulnerability Assessment.	Vulnerability Assessment failed to satisfy one of elements listed in Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 64 calendar months and less than or equal to 68 calendar months since the last benchmark GMD Vulnerability Assessment.	Vulnerability Assessment failed to satisfy two of the elements listed in Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 68 calendar months and less than or equal to 72 calendar months since the last benchmark GMD Vulnerability Assessment.	Vulnerability Assessment failed to satisfy three of the elements listed in Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 72 calendar months since the last benchmark GMD Vulnerability Assessment; OR The responsible entity does not have a completed benchmark GMD Vulnerability Assessment.
R5	~~Long-term Planning~~	~~Medium~~	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 90 calendar days and less than or	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 100 calendar days and less	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 110 calendar days after	The responsible entity did not provide the maximum effective GIC value to the Transmission Owner and Generator Owner that owns each

			equal to 100 calendar days after receipt of a written request.	than or equal to 110 calendar days after receipt of a written request.	receipt of a written request.	applicable BES power transformer in the planning area; OR The responsible entity did not provide the effective GIC time series, GIC(t), upon written request.
R6	~~Long-term Planning~~	~~Medium~~	The responsible entity failed to conduct a benchmark thermal impact assessment for 5% or less or one of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a benchmark thermal impact assessment for	The responsible entity failed to conduct a benchmark thermal impact assessment for more than 5% up to (and including) 10% or two of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a benchmark thermal	The responsible entity failed to conduct a benchmark thermal impact assessment for more than 10% up to (and including) 15% or three of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a benchmark thermal	The responsible entity failed to conduct a benchmark thermal impact assessment for more than 15% or more than three of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a benchmark thermal

			its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 24 calendar months and less than or equal to 26 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1.	impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 26 calendar months and less than or equal to 28 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include one of the required elements as listed in Requirement R6, Parts 6.1 through 6.3.	impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 28 calendar months and less than or equal to 30 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include two of the required elements as listed in Requirement R6, Parts 6.1 through 6.3.	impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 30 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include three of the required elements as listed in Requirement R6, Parts 6.1 through 6.3.
R7			The responsible entity's Corrective Action Plan failed to comply with one of the elements in	The responsible entity's Corrective Action Plan failed to comply with two of the elements in	The responsible entity's Corrective Action Plan failed to comply with three of the elements in	The responsible entity's Corrective Action Plan failed to comply with four or more of the elements

			Requirement R7, Parts 7.1 through 7.5.	Requirement R7, Parts 7.1 through 7.5.	Requirement R7, Parts 7.1 through 7.5.	in Requirement R7, Parts 7.1 through 7.5; OR The responsible entity did not have a Corrective Action Plan as required by Requirement R7.
R8			The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more than 60 calendar months and less than or equal to 64 calendar months since the last supplemental GMD Vulnerability Assessment; OR The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy one of elements listed in Requirement R8, Parts 8.1 through 8.4;	The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy two of elements listed in Requirement R8, Parts 8.1 through 8.4; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more than 64 calendar months and less than or equal to 68 calendar months since the last supplemental GMD	The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy three of the elements listed in Requirement R8, Parts 8.1 through 8.4; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more than 68 calendar months and less than or equal to 72 calendar months since the last supplemental GMD Vulnerability Assessment.	The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy four of the elements listed in Requirement R8, Parts 8.1 through 8.4; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more than 72 calendar months since the last supplemental GMD Vulnerability Assessment; OR

				Vulnerability Assessment.		The responsible entity does not have a completed supplemental GMD Vulnerability Assessment.
R9			The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 90 calendar days and less than or equal to 100 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 100 calendar days and less than or equal to 110 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 110 calendar days after receipt of a written request.	The responsible entity did not provide the maximum effective GIC value to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area; OR The responsible entity did not provide the effective GIC time series, GIC(t), upon written request.
R10			The responsible entity failed to conduct a supplemental thermal impact assessment for 5% or less or one of its solely owned and jointly owned applicable BES power	The responsible entity failed to conduct a supplemental thermal impact assessment for more than 5% up to (and including) 10% or two of its solely owned and jointly	The responsible entity failed to conduct a supplemental thermal impact assessment for more than 10% up to (and including) 15% or three of its solely owned and jointly	The responsible entity failed to conduct a supplemental thermal impact assessment for more than 15% or more than three of its solely owned and jointly owned

			transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase; OR The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 24 calendar months and less than or equal to 26 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1.	owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase; OR The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 26 calendar months and less than or equal to 28 calendar months of receiving GIC flow information specified	owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase; OR The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 28 calendar months and less than or equal to 30 calendar months of receiving GIC flow information specified	applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase; OR The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 30 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1; OR

				in Requirement R9, Part 9.1; OR The responsible entity failed to include one of the required elements as listed in Requirement R10, Parts 10.1 through 10.3.	in Requirement R9, Part 9.1; OR The responsible entity failed to include two of the required elements as listed in Requirement R10, Parts 10.1 through 10.3.	The responsible entity failed to include three of the required elements as listed in Requirement R10, Parts 10.1 through 10.3.
R11			N/A	N/A	N/A	The responsible entity did not implement a process to obtain GIC monitor data from at least one GIC monitor located in the Planning Coordinator's planning area or other part of the system included in the Planning Coordinator's GIC System Model.
R12			N/A	N/A	N/A	The responsible entity did not implement a process to obtain geomagnetic field data for its Planning Coordinator's planning area.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

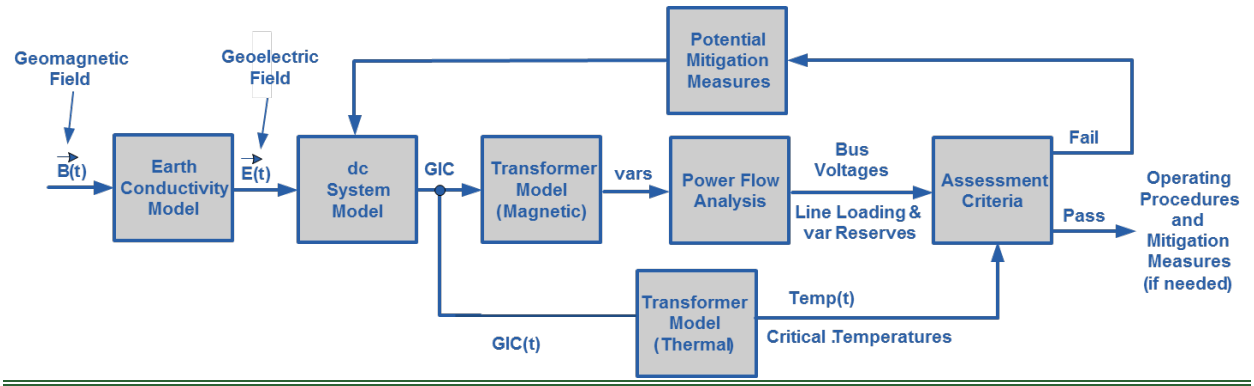
None.

Version History

Version	Date	Action	Change Tracking
1	December 17, 2014	Adopted by the NERC Board of Trustees	
2	TBD	Revised to respond to directives in FERC Order No. 830.	Revised

Guidelines and Technical Basis

The diagram below provides an overall view of the GMD Vulnerability Assessment process:



The requirements in this standard cover various aspects of the GMD Vulnerability Assessment process.

Benchmark GMD Event (Attachment 1)

The benchmark GMD event defines the geoelectric field values used to compute GIC flows that are needed to conduct a benchmark GMD Vulnerability Assessment. A white paper that includes the event description, analysis, and example calculations is available on the Project 2013-03 Geomagnetic Disturbance Mitigation project page at:

~~http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx~~http://www.nerc.com/pa/stand/Pages/TPL0071RI.aspx

Supplemental GMD Event (Attachment 1)

The supplemental GMD event defines the geoelectric field values used to compute GIC flows that are needed to conduct a supplemental GMD Vulnerability Assessment. A white paper that includes the event description and analysis is available on the Project 2013-03 Geomagnetic Disturbance Mitigation project page:
http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Requirement R2

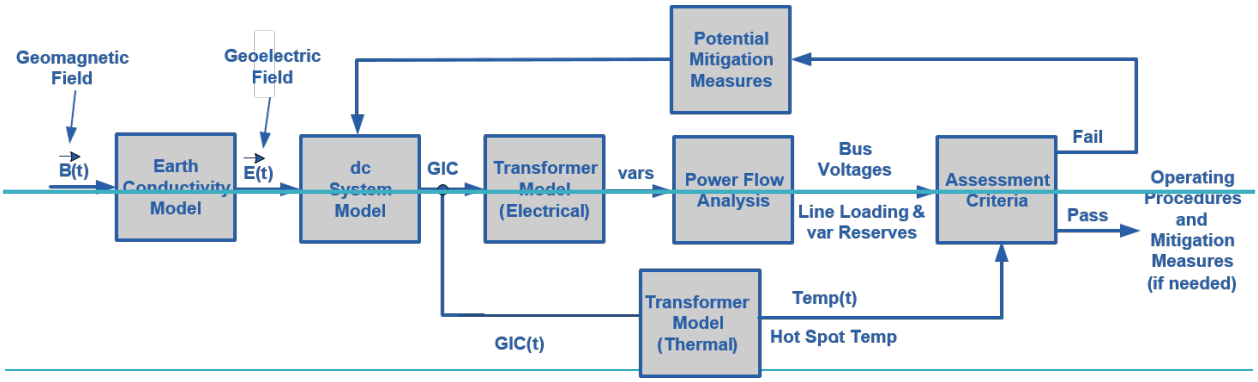
A GMD Vulnerability Assessment requires a GIC System model, which is a dc representation of the System, to calculate GIC flow. In a GMD Vulnerability Assessment, GIC simulations are used to determine transformer Reactive Power absorption and transformer thermal response. Details for developing the GIC System model are provided in the NERC GMD Task Force guide: *Application Guide for Computing Geomagnetically-Induced Current in the Bulk Power System*. The guide is available at:
http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf

Underground pipe-type cables present a special modeling situation in that the steel pipe that encloses the power conductors significantly reduces the geoelectric field induced into the conductors themselves, while they remain a path for GIC. Solid dielectric cables that are not enclosed by a steel pipe will not experience a reduction in the induced geoelectric field. A planning entity should account for special modeling situations in the GIC system model, if applicable.

Requirement R4

The *GMD Planning Guide* developed by the NERC GMD Task Force provides technical information on GMD-specific considerations for planning studies. It is available at: http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf

~~The diagram below provides an overall view of the GMD Vulnerability Assessment process:~~



Requirement R5

The ~~transformer~~benchmark thermal impact assessment of transformers specified in Requirement R6 is based on GIC information for the ~~Benchmark~~benchmark GMD Event. This GIC information is determined by the planning entity through simulation of the GIC System model and must be provided to the entity responsible for conducting the thermal impact assessment. GIC information should be provided in accordance with Requirement R5 each time the GMD Vulnerability Assessment is performed since, by definition, the GMD Vulnerability Assessment includes a documented evaluation of susceptibility to localized equipment damage due to GMD.

The maximum effective GIC value provided in Part 5.1 is used for ~~transformer~~the benchmark thermal impact assessment. Only those transformers that experience an effective GIC value of 75 A or greater per phase require evaluation in Requirement R6.

GIC(t) provided in Part 5.2 is used to convert the steady ~~-~~state GIC flows to time-series GIC data for ~~transformer~~the benchmark thermal impact assessment~~.~~ of transformers. This information may be needed by one or more of the methods for performing a benchmark thermal impact assessment. Additional information is in the following section and the thermal impact assessment white paper.

The peak GIC value of 75 Amps per phase has been shown through thermal modeling to be a conservative threshold below which the risk of exceeding known temperature limits established by technical organizations is low.

Requirement R6

The benchmark thermal impact assessment of a power transformer may be based on manufacturer-provided GIC capability curves, thermal response simulation, thermal impact screening, or other technically justified means. Approaches for conducting the assessment are presented in the *Transformer Thermal Impact Assessment* white paper ~~posted on the project page.~~ The ERO enterprise has endorsed the white paper as Implementation Guidance for this requirement. The white paper is posted on the NERC compliance guidance page: ~~http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx~~

http://www.nerc.com/pa/comp/guidance/Pages/default.aspx

Transformers are exempt from the benchmark thermal impact assessment requirement if the effective GIC value for the transformer is less than 75 A per phase, as determined by a GIC analysis of the System. Justification for this criterion is provided in the *Screening Criterion for Transformer Thermal Impact Assessment* white paper posted on the Related Information page for ~~project~~TPL-007-1. A documented design specification exceeding this value is also a justifiable threshold criterion that exempts a transformer from Requirement R6.

The benchmark threshold criteria and its associated transformer thermal impact must be evaluated on the basis of effective GIC. Refer to the white papers for additional information.

Requirement R7

Technical considerations for GMD mitigation planning, including operating and equipment strategies, are available in Chapter 5 of the *GMD Planning Guide*. Additional information is available in the *2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk-Power System*: http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2012GMD.pdf

Requirement R8

The *GMD Planning Guide* developed by the NERC GMD Task Force provides technical information on GMD-specific considerations for planning studies. It is available at: http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf

The supplemental GMD Vulnerability Assessment process is similar to the benchmark GMD Vulnerability Assessment process described under Requirement R4.

Requirement R9

The supplemental thermal impact assessment specified of transformers in Requirement R10 is based on GIC information for the supplemental GMD Event. This GIC information is determined by the planning entity through simulation of the GIC System model and must be provided to the entity responsible for conducting the thermal impact assessment. GIC information should be provided in accordance with Requirement R9 each time the GMD Vulnerability Assessment is performed since, by definition, the GMD Vulnerability Assessment includes a documented evaluation of susceptibility to localized equipment damage due to GMD.

The maximum effective GIC value provided in Part 9.1 is used for the supplemental thermal impact assessment. Only those transformers that experience an effective GIC value of 85 A or greater per phase require evaluation in Requirement R10.

GIC(t) provided in Part 9.2 is used to convert the steady state GIC flows to time-series GIC data for the supplemental thermal impact assessment of transformers. This information may be needed by one or more of the methods for performing a supplemental thermal impact assessment. Additional information is in the following section.

The peak GIC value of 85 Amps per phase has been shown through thermal modeling to be a conservative threshold below which the risk of exceeding known temperature limits established by technical organizations is low.

Requirement R10

The supplemental thermal impact assessment of a power transformer may be based on manufacturer-provided GIC capability curves, thermal response simulation, thermal impact screening, or other technically justified means. Approaches for conducting the assessment are presented in the *Transformer Thermal Impact Assessment* white paper discussed in the Requirement R6 section above. A revised version of the Transformer Thermal Impact Assessment white paper has been developed to include updated information pertinent to the supplemental GMD event and supplemental thermal impact assessment. This revised white paper is posted on the project page at:

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

Transformers are exempt from the supplemental thermal impact assessment requirement if the effective GIC value for the transformer is less than 85 A per phase, as determined by a GIC analysis of the System. Justification for this criterion is provided in the revised *Screening*

Criterion for Transformer Thermal Impact Assessment white paper posted on the project page. A documented design specification exceeding this value is also a justifiable threshold criterion that exempts a transformer from Requirement R10.

The supplemental threshold criteria and its associated transformer thermal impact must be evaluated on the basis of effective GIC. Refer to the white papers for additional information.

Requirement R11

Technical considerations for GIC monitoring are contained in the NERC 2012 GMD Report (see Chapter 6). GIC monitoring is generally performed by Hall effect transducers that are attached to the neutral of the wye-grounded transformer. Data from GIC monitors is useful model validation and situational awareness.

Responsible entities consider the following in developing a process for obtaining GIC monitor data:

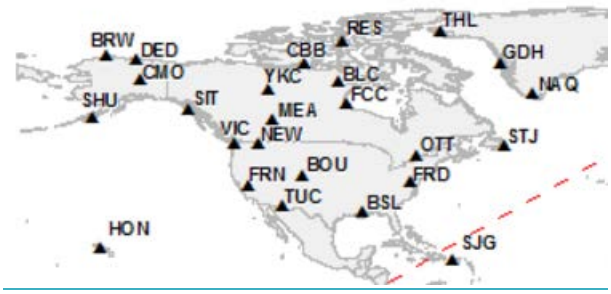
- **Monitor locations.** An entity's operating process may be constrained by location of existing GIC monitors. However, when planning for additional GIC monitoring installations consider that data from monitors located in areas found to have high GIC based on system studies may provide more useful information for validation and situational awareness purposes. Conversely, data from GIC monitors that are located in the vicinity of transportation systems using direct current (e.g., subways or light rail) may be unreliable.
- **Monitor specifications.** Capabilities of Hall effect transducers, existing and planned, should be considered in the operating process. When planning new GIC monitor installations, consider monitor data range (e.g., -500 A through + 500 A) and ambient temperature ratings consistent with temperatures in the region in which the monitor will be installed.
- **Sampling Interval.** An entity's operating process may be constrained by capabilities of existing GIC monitors. However, when possible specify data sampling during periods of interest at a rate of 10 seconds or faster.
- **Collection Periods.** The process should specify when the entity expects GIC data to be collected. For example, collection could be required during periods where the Kp index is above a threshold, or when GIC values are above a threshold. Determining when to discontinue collecting GIC data should also be specified to maintain consistency in data collection.
- **Data format.** Specify time and value formats. For example, Greenwich Mean Time (GMT) (MM/DD/YYYY HH:MM:SS) and GIC Value (Ampere). Positive (+) and negative (-) signs indicate direction of GIC flow. Positive reference is flow from ground into transformer neutral. Time fields should indicate the sampled time rather than system or SCADA time if supported by the GIC monitor system.
- **Data retention.** The entity's process should specify data retention periods, for example 1 year. Data retention periods should be adequately long to support availability for the entity's model validation process and external reporting requirements, if any.

- **Additional information.** The entity's process should specify collection of other information necessary for making the data useful, for example monitor location and type of neutral connection (e.g., three-phase or single-phase).

Requirement R12

Magnetometers measure changes in the earth's magnetic field. Entities should obtain data from the nearest accessible magnetometer. Sources of magnetometer data include:

- Observatories such as those operated by U.S. Geological Survey and Natural Resources Canada, see figure below for locations (http://www.intermagnet.org/):



- Research institutions and academic universities;
- Entities with installed magnetometers.

Entities that choose to install magnetometers should consider equipment specifications and data format protocols contained in the latest version of the Intermagnet Technical Reference Manual, which is available at:
http://www.intermagnet.org/publications/intermag_4-6.pdf

Rationale:

During development of ~~this standard~~TPL-007-1, text boxes were embedded within the standard to explain the rationale for various parts of the standard. ~~Upon BOT approval, the~~The text from the rationale text boxes was moved to this section~~.~~ upon approval of TPL-007-1 by the NERC Board of Trustees. In developing TPL-007-2, the SDT has made changes to the sections below only when necessary for clarity. Changes are marked with brackets [ ].

Rationale for Applicability:
Instrumentation transformers and station service transformers do not have significant impact on geomagnetically-induced current (GIC) flows; therefore, these transformers are not included in the applicability for this standard.

Terminal voltage describes line-to-line voltage.

Rationale for R1:
In some areas, planning entities may determine that the most effective approach to conduct a GMD Vulnerability Assessment is through a regional planning organization. No requirement in the standard is intended to prohibit a collaborative approach where roles and responsibilities are determined by a planning organization made up of one or more Planning Coordinator(s).

Rationale for R2:
A GMD Vulnerability Assessment requires a GIC System model to calculate GIC flow which is used to determine transformer Reactive Power absorption and transformer thermal response. Guidance for developing the GIC System model is provided in the GIC Application Guide developed by the NERC GMD Task Force and available at: http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf

The System model specified in Requirement R2 is used in conducting steady state power flow analysis that accounts for the Reactive Power absorption of power transformer(s) due to GIC in the System.

The GIC System model includes all power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV. The model is used to calculate GIC flow in the network.

The projected System condition for GMD planning may include adjustments to the System that are executable in response to space weather information. These adjustments could include, for example, recalling or postponing maintenance outages.

The Violation Risk Factor (VRF) for Requirement R2 is changed from Medium to High. This change is for consistency with the VRF for approved standard TPL-001-4 Requirement R1, which is proposed for revision in the NERC filing dated August 29, 2014 (RM12-1-000). NERC guidelines require consistency among Reliability Standards.

Rationale for R3:
Requirement R3 allows a responsible entity the flexibility to determine the System steady state voltage criteria for System steady state performance in Table 1. Steady state voltage limits are an example of System steady state performance criteria.

Rationale for R4:
The GMD Vulnerability Assessment includes steady state power flow analysis and the supporting study or studies using the models specified in Requirement R2 that account for the effects of GIC. Performance criteria are specified in Table 1.

At least one System On-Peak Load and at least one System Off-Peak Load must be examined in the analysis.

Distribution of GMD Vulnerability Assessment results provides a means for sharing relevant information with other entities responsible for planning reliability. Results of GIC studies may affect neighboring systems and should be taken into account by planners.

The GMD Planning Guide developed by the NERC GMD Task Force provides technical information on GMD-specific considerations for planning studies. It is available at:

http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf

The provision of information in Requirement R4, Part 4.3, shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

Rationale for R5:
This GIC information is necessary for determining the thermal impact of GIC on transformers in the planning area and must be provided to entities responsible for performing the thermal impact assessment so that they can accurately perform the assessment. GIC information should be provided in accordance with Requirement R5 as part of the GMD Vulnerability Assessment process since, by definition, the GMD Vulnerability Assessment includes documented evaluation of susceptibility to localized equipment damage due to GMD.

The maximum effective GIC value provided in Part 5.1 is used for transformer thermal impact assessment.

GIC(t) provided in Part 5.2 can alternatively be used to convert the steady -state GIC flows to time-series GIC data for transformer thermal impact assessment. This information may be needed by one or more of the methods for performing a thermal impact assessment. Additional guidance is available in the Transformer Thermal Impact Assessment white paper:

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

[http://www.nerc.com/pa/comp/guidance/Pages/default.aspx]

A Transmission Owner or Generator Owner that desires GIC(t) may request it from the planning entity. The planning entity shall provide GIC(t) upon request once GIC has been calculated, but no later than 90 calendar days after receipt of a request from the owner and after completion of Requirement R5, Part 5.1.

The provision of information in Requirement R5 shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

Rationale for R6:

The transformer thermal impact screening criterion has been revised from 15 A per phase to 75 A per phase~~.~~ [for the benchmark GMD event]. Only those transformers that experience an effective GIC value of 75 A per phase or greater require evaluation in Requirement R6. The justification is provided in the Thermal Screening Criterion white paper.

The thermal impact assessment may be based on manufacturer-provided GIC capability curves, thermal response simulation, thermal impact screening, or other technically justified means. The transformer thermal assessment will be repeated or reviewed using previous assessment results each time the planning entity performs a GMD Vulnerability Assessment and provides GIC information as specified in Requirement R5. Approaches for conducting the assessment are presented in the Transformer Thermal Impact Assessment white paper posted on the project page.

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

Thermal impact assessments are provided to the planning entity, as determined in Requirement R1, so that identified issues can be included in the GMD Vulnerability Assessment (R4), and the Corrective Action Plan (R7) as necessary.

Thermal impact assessments of non-BES transformers are not required because those transformers do not have a wide-area effect on the reliability of the interconnected Transmission system.

The provision of information in Requirement R6, Part 6.4, shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

Rationale for R7:
Corrective Action Plans are defined in the NERC Glossary of Terms:

> *A list of actions and an associated timetable for implementation to remedy a specific problem.*

Corrective Action Plans must, subject to the vulnerabilities identified in the assessments, contain strategies for protecting against the potential impact of the ~~Benchmark~~[Bb]enchmark GMD event, based on factors such as the age, condition, technical specifications, system configuration, or location of specific equipment. Chapter 5 of the NERC GMD Task Force *GMD Planning Guide* provides a list of mitigating measures that may be appropriate to address an identified performance issue.

The provision of information in Requirement R7, Part 7.3~~,~~ [Part 7.5 in TPL-007-2], shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

Rationale for Table 3:
Table 3 has been revised to use the same ground model designation, FL1, as is being used by USGS. The calculated scaling factor for FL1 is 0.74~~.~~ [The scaling factor associated with the benchmark GMD event for the Florida earth model (FL-1) has been updated to 0.76 in TPL-007-2 based on the earth model published on the USGS public website.]

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Violation Risk Factor and Violation Severity Level Justifications

TPL-007-2 – Transmission System Planned Performance for Geomagnetic Disturbance Events

This document provides the Standard Drafting Team's (SDT) justification for assignment of Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for each requirement in TPL-007-2 – Transmission System Planned Performance for Geomagnetic Disturbance Events. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project.

NERC Criteria - Violation Risk Factors

High Risk Requirement

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

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

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

FERC Violation Risk Factor Guidelines

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

The Commission seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders

- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
The Commission expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
The Commission expects the assignment of VRFs corresponding to requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) –Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria - Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

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

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

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

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

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

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

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

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

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

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

VRF Justifications – TPL-007-2, R1	
Proposed VRF	**Low**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report. N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard. The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. A VRF of Lower is consistent with Reliability Standard TPL-001-4 Requirement R7, which requires the Planning Coordinator, in conjunction with each of its Transmission Planners, to identify each entity's individual and joint responsibilities for performing required studies for the Planning Assessment. Proposed TPL-007-2 Requirement R1 requires Planning Coordinators, in conjunction with Transmission Planners, to identify individual and joint responsibilities for maintaining models and performing studies needed to complete the benchmark and supplemental GMD Vulnerability Assessments, and implementing process(es) to obtain GMD measurement data as specified in the Standard.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. A VRF of Lower is consistent with the NERC VRF definition. The requirement for identifying individual and joint responsibilities of the Planning Coordinator and each of the Transmission Planners in the Planning Coordinator's planning area for maintaining models, performing GMD studies, and obtaining GMD measurement data, 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, control, or restore the Bulk Electric System under conditions of a GMD event.

VRF Justifications – TPL-007-2, R1	
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. The requirement contains one objective, therefore a single VRF is assigned.

Proposed VSLs – TPL-007-2, R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Planning Coordinator, in conjunction with its Transmission Planner(s), failed to determine and identify individual or joint responsibilities of the Planning Coordinator and Transmission Planner(s) in the Planning Coordinator's planning area for maintaining models, performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments, and implementing process(es) to obtain GMD measurement data as specified in the Standard.

VSL Justifications – TPL-007-2, R1	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement does not have elements or quantities to evaluate degrees of compliance. A VSL of Severe is assigned for non-compliance.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSL is not changed in TPL-007-2.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is binary and assigned a Severe VSL. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be	The proposed VSL is worded consistently with the corresponding requirement.

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

VRF Justifications – TPL-007-2, R2	
Proposed VRF	**High**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. A VRF of High is consistent with the VRF for Reliability Standard TPL-001-4 Requirement R1 as amended in NERC's filing dated August 29, 2014, which requires Transmission Planners and Planning Coordinators to maintain models within its respective planning area for performing studies needed to complete its Planning Assessment. Proposed TPL-007-2, Requirement R2 requires responsible entities to maintain System models and GIC System models of the responsible entity's planning area for performing the studies needed to complete benchmark and supplemental GMD Vulnerability Assessments.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. The VRF of High is consistent with the NERC VRF Definition. The System Models and GIC System Models serve as the foundation for all conditions and events that are required to be studied and evaluated in the benchmark and supplemental GMD Vulnerability Assessments. For this reason, failure to maintain models of the responsible entity's planning area for performing GMD studies could, under GMD conditions that are as severe as the benchmark and supplemental GMD event, 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. This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

Proposed VSLs – TPL-007-2, R2			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The responsible entity did not maintain either System models or GIC System models of the responsible entity's planning area for performing the study or studies or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments.	The responsible entity did not maintain both System models and GIC System models of the responsible entity's planning area for performing the study or studies or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments.

VSL Justifications – TPL-007-2, R2	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement may be described by elements or quantities to evaluate degrees of compliance. Two VSLs are specified for a graduated scale.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSL is not changed in TPL-007-2.
FERC VSL G2	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties.

VSL Justifications – TPL-007-2, R2	
Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications – TPL-007-2, R3	
Proposed VRF	**Medium**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. A VRF of Medium is consistent with Reliability Standard TPL-001-4 Requirement R5 which requires Transmission Planners and Planning Coordinators to have criteria for acceptable System steady state voltage limits. Proposed TPL-007-2 Requirement R4 requires responsible entities to have criteria for acceptable System steady state voltage performance for its System during the benchmark GMD event; these criteria may be different from the voltage limits determined in Reliability Standard TPL-001-4 Requirement R5.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. The VRF of Medium is consistent with the NERC VRF Definition. Failure to have criteria for acceptable System steady state voltage limits for its System during a GMD planning event could 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 during an actual GMD event. However, it is unlikely that such a failure by itself would lead to Bulk Electric System instability, separation, or cascading.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

Proposed VSLs – TPL-007-2, R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The responsible entity did not have criteria for acceptable

Proposed VSLs – TPL-007-2, R3			
			System steady state voltage performance for its System during the GMD events described in Attachment 1 as required.

VSL Justifications – TPL-007-2, R3	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement does not have elements or quantities to evaluate degrees of compliance. A VSL of Severe is assigned for non-compliance.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSL is not changed in TPL-007-2.
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	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is binary and assigned a Severe VSL.

VSL Justifications – TPL-007-2, R3	
"Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications – TPL-007-2, R4	
Proposed VRF	**High**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. A VRF of High is consistent with Reliability Standard TPL-001-4 Requirement R2 which requires Transmission Planners and Planning Coordinators to prepare an annual Planning Assessment to ensure its portion of the Bulk Electric System meets performance criteria. Proposed TPL-007-2 Requirement R4 requires responsible entities to complete a benchmark GMD Vulnerability Assessment to ensure the system meets performance criteria during the benchmark GMD event.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. The VRF of High is consistent with the NERC VRF Definition. Failure to complete a benchmark GMD Vulnerability Assessment could, under GMD conditions that are as severe as the benchmark GMD event, 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. This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

Proposed VSLs – TPL-007-2, R4			
Lower	**Moderate**	**High**	**Severe**
The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 60 calendar	The responsible entity's completed benchmark GMD Vulnerability Assessment failed to satisfy one of elements listed	The responsible entity's completed benchmark GMD Vulnerability Assessment failed to satisfy two of the elements	The responsible entity's completed benchmark GMD Vulnerability Assessment failed to satisfy three of the elements

Proposed VSLs – TPL-007-2, R4			
months and less than or equal to 64 calendar months since the last benchmark GMD Vulnerability Assessment.	in Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 64 calendar months and less than or equal to 68 calendar months since the last benchmark GMD Vulnerability Assessment.	listed in Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 68 calendar months and less than or equal to 72 calendar months since the last benchmark GMD Vulnerability Assessment.	listed in Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 72 calendar months since the last benchmark GMD Vulnerability Assessment; OR The responsible entity does not have a completed benchmark GMD Vulnerability Assessment.

VSL Justifications – TPL-007-2, R4	
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	The VSL is not changed in TPL-007-2.

VSL Justifications – TPL-007-2, R4	
Lowering the Current Level of Compliance	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A	The proposed VSL is not based on a cumulative number of violations.

VSL Justifications – TPL-007-2, R4	
Cumulative Number of Violations	

VRF Justifications – TPL-007-2, R5	
Proposed VRF	**Medium**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. A VRF of Medium is consistent with Reliability Standard MOD-032-1 Requirement R2 which requires applicable entities to provide modeling data to Transmission Planners and Planning Coordinators. A VRF of Medium is also consistent with Reliability Standard IRO-010-2 Requirement R3 which requires entities to provide data necessary for the Reliability Coordinator to perform its Operational Planning Analysis and Real-time Assessments. Proposed TPL-007-2 Requirement R5 requires responsible entities to provide specific geomagnetically-induced currents (GIC) flow information to Transmission Owners and Generator Owners for performing transformer thermal impact assessments.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. The VRF of Medium is consistent with the NERC VRF Definition. Failure to provide GIC flow information for the benchmark GMD event could 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 during a GMD event. However, it is unlikely that such a failure by itself would lead to Bulk Electric System instability, separation, or cascading.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

Proposed VSLs – TPL-007-2, R5			
Lower	**Moderate**	**High**	**Severe**
The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 90 calendar days and less than or equal to 100 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 100 calendar days and less than or equal to 110 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 110 calendar days after receipt of a written request.	The responsible entity did not provide the maximum effective GIC value to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area; OR The responsible entity did not provide the effective GIC time series, GIC(t), upon written request.

VSL Justifications – TPL-007-2, R5	
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	The VLS is not changed in TPL-007-2.

VSL Justifications – TPL-007-2, R5	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties.
Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent	Guideline 2a: The proposed VSL is not binary.
Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications – TPL-007-2, R6	
Proposed VRF	**Medium**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. A VRF of Medium is consistent with Reliability Standard FAC-008-3 Requirement R6 which requires Transmission Owners and Generator Owners to have Facility Ratings for all solely and jointly owned Facilities that are consistent with the associated Facility Ratings methodology or documentation. Proposed TPL-007-2 Requirement R6 requires responsible entities to conduct a benchmark thermal impact assessment for solely and jointly owned applicable transformers and provide results including suggested actions to mitigate identified impacts to planning entities.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. The VRF of Medium is consistent with the NERC VRF Definition. Failure to conduct a benchmark transformer thermal impact assessment could 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 during a GMD event. However, it is unlikely that such a failure by itself would lead to Bulk Electric System instability, separation, or cascading.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

Proposed VSLs – TPL-007-2, R6			
Lower	**Moderate**	**High**	**Severe**
The responsible entity failed to conduct a benchmark thermal impact assessment for 5% or less or one of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a benchmark thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 24 calendar months and less than or equal to 26 calendar months	The responsible entity failed to conduct a benchmark thermal impact assessment for more than 5% up to (and including) 10% or two of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a benchmark thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 26 calendar months and less than or equal to 28 calendar months	The responsible entity failed to conduct a benchmark thermal impact assessment for more than 10% up to (and including) 15% or three of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a benchmark thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 28 calendar months and less than or equal to 30 calendar months	The responsible entity failed to conduct a benchmark thermal impact assessment for more than 15% or more than three of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a benchmark thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 30 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1;

Proposed VSLs – TPL-007-2, R6			
of receiving GIC flow information specified in Requirement R5, Part 5.1.	of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include one of the required elements as listed in Requirement R6, Parts 6.1 through 6.3.	of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include two of the required elements as listed in Requirement R6, Parts 6.1 through 6.3.	OR The responsible entity failed to include three of the required elements as listed in Requirement R6, Parts 6.1 through 6.3.

VSL Justifications – TPL-007-2, R6	
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	The VSL is not changed in TPL-007-2.
FERC VSL G2 Violation Severity Level Assignments Should Ensure	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties.

VSL Justifications – TPL-007-2, R6	
Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications – TPL-007-2, R7	
Proposed VRF	**High**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. A VRF of High is consistent with Reliability Standard TPL-001-4 Requirement R2 which requires Transmission Planners and Planning Coordinators to include a Corrective Action Plan that addresses identified performance issues in the annual Planning Assessment. Proposed TPL-007-2 Requirement R7 requires responsible entities to develop a Corrective Action Plan when results of the benchmark GMD Vulnerability Assessment indicate that the System does not meet performance requirements. While Reliability Standard TPL-001-4 has a single requirement for performing the Planning Assessment and developing the Corrective Action Plan, proposed TPL-007-2 has split the requirements for performing a benchmark GMD Vulnerability Assessment and developing the Corrective Action Plan into two separate requirements because the transformer thermal impact assessments performed by Transmission Owners and Generator Owners must be considered. The sequencing with separate requirements follows a logical flow of the GMD Vulnerability Assessment process.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. The VRF of High is consistent with the NERC VRF Definition. Failure to develop a Corrective Action Plan that addresses issues identified in a GMD Vulnerability Assessment could, under GMD conditions that are as severe as the benchmark GMD event, 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. This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

Proposed VSLs – TPL-007-2, R7			
Lower	**Moderate**	**High**	**Severe**
The responsible entity's Corrective Action Plan failed to comply with one of the elements in Requirement R7, Parts 7.1 through 7.5.	The responsible entity's Corrective Action Plan failed to comply with two of the elements in Requirement R7, Parts 7.1 through 7.5.	The responsible entity's Corrective Action Plan failed to comply with three of the elements in Requirement R7, Parts 7.1 through 7.5.	The responsible entity's Corrective Action Plan failed to comply with four or more of the elements in Requirement R7, Parts 7.1 through 7.5; OR The responsible entity did not have a Corrective Action Plan as required by Requirement R7.

VSL Justifications – TPL-007-2, R7	
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	The proposed requirement is a significant revision to TPL-007-2 to address the directive for Corrective Action Plan deadlines contained in FERC Order No. 830. There is no prior compliance obligation related to the directive. However, the requirement uses the same construct for a graduated scale as TPL-007-1 Requirement R7 and is similar to Reliability Standard TPL-001-4, Requirement R2.
FERC VSL G2 Violation Severity Level Assignments Should Ensure	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties.

VSL Justifications – TPL-007-2, R7	
Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications – TPL-007-2, R8	
Proposed VRF	**High**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. A VRF of High is consistent with Reliability Standard TPL-001-4 Requirement R2 which requires Transmission Planners and Planning Coordinators to prepare an annual Planning Assessment to ensure its portion of the Bulk Electric System meets performance criteria. The proposed requirement is also consistent with approved TPL-007-1 Requirement R4 (unchanged in proposed TPL-007-2 Requirement R4). Proposed TPL-007-2 Requirement R8 requires responsible entities to complete a supplemental GMD Vulnerability Assessment to assess system performance during a supplemental GMD event.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. The VRF of High is consistent with the NERC VRF Definition. Failure to complete a supplemental GMD Vulnerability Assessment could, under GMD conditions that are as severe as the supplemental GMD event, place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures by precluding responsible entities from considering actions to mitigate risk of Cascading.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

Proposed VSLs – TPL-007-2, R8			
Lower	**Moderate**	**High**	**Severe**
The responsible entity completed a supplemental GMD	The responsible entity's completed supplemental GMD	The responsible entity's completed supplemental GMD	The responsible entity's completed supplemental GMD

Proposed VSLs – TPL-007-2, R8			
Vulnerability Assessment, but it was more than 60 calendar months and less than or equal to 64 calendar months since the last supplemental GMD Vulnerability Assessment; OR The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy one of elements listed in Requirement R8, Parts 8.1 through 8.4;	Vulnerability Assessment failed to satisfy two of elements listed in Requirement R8, Parts 8.1 through 8.4; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more than 64 calendar months and less than or equal to 68 calendar months since the last supplemental GMD Vulnerability Assessment.	Vulnerability Assessment failed to satisfy three of the elements listed in Requirement R8, Parts 8.1 through 8.4; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more than 68 calendar months and less than or equal to 72 calendar months since the last supplemental GMD Vulnerability Assessment.	Vulnerability Assessment failed to satisfy four of the elements listed in Requirement R8, Parts 8.1 through 8.4; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more than 72 calendar months since the last supplemental GMD Vulnerability Assessment; OR The responsible entity does not have a completed supplemental GMD Vulnerability Assessment.

VSL Justifications – TPL-007-2, R8	
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	There is no prior compliance obligation related to supplemental GMD Vulnerability Assessment. However, the requirement is similar to approved TPL-007-1, Requirement R4 (unchanged in proposed TPL-007-2 Requirement R4). That requirement also has a graduated scale for VSLs.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be	The proposed VSL is worded consistently with the corresponding requirement.

VSL Justifications – TPL-007-2, R8	
Consistent with the Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications – TPL-007-2, R9	
Proposed VRF	**Medium**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. A VRF of Medium is consistent with approved TPL-007-1 Requirement R5 (unchanged in proposed TPL-007-2 Requirement R5) which requires responsible entities to provide specific geomagnetically-induced currents (GIC) flow information to Transmission Owners and Generator Owners for performing transformer thermal impact assessments.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. The VRF of Medium is consistent with the NERC VRF Definition. Failure to provide GIC flow information for the supplemental GMD event could 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 during a GMD event. However, it is unlikely that such a failure by itself would lead to Bulk Electric System instability, separation, or cascading.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

Proposed VSLs – TPL-007-2, R9			
Lower	**Moderate**	**High**	**Severe**
The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than	The responsible entity did not provide the maximum effective GIC value to the Transmission Owner and Generator Owner

Proposed VSLs – TPL-007-2, R9			
90 calendar days and less than or equal to 100 calendar days after receipt of a written request.	100 calendar days and less than or equal to 110 calendar days after receipt of a written request.	110 calendar days after receipt of a written request.	that owns each applicable BES power transformer in the planning area; OR The responsible entity did not provide the effective GIC time series, GIC(t), upon written request.

VSL Justifications – TPL-007-2, R9	
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	There is no prior compliance obligation related to supplemental GMD Vulnerability Assessment. However, the requirement is similar to approved TPL-007-1, Requirement R5 (unchanged in proposed TPL-007-2 Requirement R5). That requirement also has a graduated scale for VSLs.
FERC VSL G2 Violation Severity Level Assignments Should Ensure	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties.

VSL Justifications – TPL-007-2, R9	
Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications – TPL-007-2, R10	
Proposed VRF	**Medium**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. A VRF of Medium is consistent with approved TPL-007-1 Requirement R6 (unchanged in proposed TPL-007-2 Requirement R6), which requires responsible entities to conduct a benchmark thermal impact assessment for solely and jointly owned applicable transformers and provide results including suggested actions to mitigate identified impacts to planning entities.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. The VRF of Medium is consistent with the NERC VRF Definition. Failure to conduct a supplemental transformer thermal impact assessment could 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 during a GMD event. However, it is unlikely that such a failure by itself would lead to Bulk Electric System instability, separation, or cascading.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

Proposed VSLs – TPL-007-2, R10			
Lower	**Moderate**	**High**	**Severe**
The responsible entity failed to conduct a supplemental thermal impact assessment for 5% or	The responsible entity failed to conduct a supplemental thermal impact assessment for more	The responsible entity failed to conduct a supplemental thermal impact assessment for more	The responsible entity failed to conduct a supplemental thermal impact assessment for more

Proposed VSLs – TPL-007-2, R10			
less or one of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase; OR The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 24 calendar months and less than or equal to 26 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1.	than 5% up to (and including) 10% or two of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase; OR The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 26 calendar months and less than or equal to 28 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1; OR	than 10% up to (and including) 15% or three of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase; OR The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 28 calendar months and less than or equal to 30 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1; OR	than 15% or more than three of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase; OR The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 30 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1; OR The responsible entity failed to include three of the required elements as listed in

Proposed VSLs – TPL-007-2, R10			
	The responsible entity failed to include one of the required elements as listed in Requirement R10, Parts 10.1 through 10.3.	The responsible entity failed to include two of the required elements as listed in Requirement R10, Parts 10.1 through 10.3.	Requirement R10, Parts 10.1 through 10.3.

VSL Justifications – TPL-007-2, 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	There is no prior compliance obligation related to supplemental thermal impact assessment. However, the requirement is similar to approved TPL-007-1, Requirement R6 (unchanged in proposed TPL-007-2 Requirement R6). That requirement also has a graduated scale for VSLs.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary.

VSL Justifications – TPL-007-2, R10	
Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications – TPL-007-2, R11	
Proposed VRF	**Lower**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. A VRF of Lower is consistent with approved Reliability Standards requiring entities to implement processes to obtain data. These include Reliability Standard MOD-032-1 Requirement R1 and Reliability Standard IRO-010-2 Requirement R1.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. The VRF of Lower is consistent with the NERC VRF Definition. Failure to obtain GIC monitor data from at least one GIC monitor located in the system would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

Proposed VSLs – TPL-007-2, R11			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The responsible entity did not implement a process to obtain GIC monitor data from at least one GIC monitor located in the Planning Coordinator's planning area or other part of the system included in the Planning

Proposed VSLs – TPL-007-2, R11			
			Coordinator's GIC System Model.

VSL Justifications – TPL-007-2, R11	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement does not have elements or quantities to evaluate degrees of compliance. A VSL of Severe is assigned for non-compliance.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation for this requirement.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is binary and assigned a Severe VSL.

VSL Justifications – TPL-007-2, R11	
Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications – TPL-007-2, R12	
Proposed VRF	**Lower**
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: N/A
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards. A VRF of Lower is consistent with approved Reliability Standards requiring entities to implement processes to obtain data. These include Reliability Standard MOD-032-1 Requirement R1 and Reliability Standard IRO-010-2 Requirement R1.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs. The VRF of Lower is consistent with the NERC VRF Definition. Failure to obtain geomagnetic field data for the planning area would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation. This requirement does not co-mingle a higher-risk reliability objective with a lesser- risk reliability objective.

Proposed VSLs – TPL-007-2, R12			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The responsible entity did not implement a process to obtain geomagnetic field data for its Planning Coordinator's planning area.

VSL Justifications – TPL-007-2, R12	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The requirement does not have elements or quantities to evaluate degrees of compliance. A VSL of Severe is assigned for non-compliance.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation for this requirement.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is binary and assigned a Severe VSL. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be	The proposed VSL is worded consistently with the corresponding requirement.

VSL Justifications – TPL-007-2, R12	
Consistent with the Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

Consideration of Directives

Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events

Order No. 830, 156 FERC ¶ 61,215 (Sep. 22, 2016)

approving Reliability Standard TPL-007-1

#	P	Directive/Guidance	Resolution
1)	**PP 44** 47-49	**MODIFY THE BENCHMARK GMD EVENT re SPATIAL AVERAGING** P44: "[T]he 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." P47: "Without prejudging how NERC proposes to address the Commission's directive, NERC's response to this directive 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." P48: "NERC could revise [the standard] 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 Trade Associations." P49: "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."	The directive is addressed in proposed TPL-007-2 through Requirements for applicable entities to perform supplemental GMD Vulnerability Assessments based on the supplemental GMD event. The supplemental GMD event is a defined event for assessing system performance that is not based on spatially-averaged data. The supplemental GMD event is described in the standard drafting team's (SDT) white paper available on the project page: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx
2)	**P65**	**REVISE R6 RE SPATIAL AVERAGING** P65: "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	The directive is addressed in proposed TPL-007-2 Requirements R9 and R10. Applicable entities use geomagnetically-induced current (GIC) information for the supplemental GMD event to perform supplemental thermal impact assessments of applicable power

#	P	Directive/Guidance	Resolution
		to apply spatially averaged and non-spatially averaged peak geoelectric field values, or some equally efficient and effective alternative, when conducting thermal impact assessments."	transformers. Requirement R9 obligates responsible Planning Coordinators and Transmission Planners to provide GIC flow information to Transmission Owners and Generator Owners for performing supplemental thermal impact assessments. The GIC flow information is based on the supplemental GMD event. Requirement R10 obligates Transmission Owners and Generator Owners to perform supplemental thermal impact assessments on applicable power transformers and provide results to responsible Planning Coordinators and Transmission Planners.
3)	**PP 88** 90, 91, 92	**REVISE STANDARD TO REQUIRE COLLECTION OF GMD DATA** P 88: "The Commission … adopts the NOPR proposal in relevant part an 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." *GIC Requirements* P 91: "Each responsible entity that is a transmission owner should be	The directive is addressed in proposed TPL-007-2 Requirements R11 and R12. Requirement R11 obligates responsible Planning Coordinators and Transmission Planners to implement a process to obtain GIC monitor data from at least one GIC monitor located in the Planning Coordinator's planning area or other part of the system included in the Planning Coordinator's GIC System model. The SDT described GIC data collection criteria in the guidance section to promote consistency in achieving the reliability objective and provide responsible entities with flexibility to tailor procedures to their planning area. The guidance addresses the following considerations: monitor locations, monitor specifications, sampling interval, collection periods, data format, and data retention.

#	P	Directive/Guidance	Resolution
		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 little or no 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 (e.g., subways or light rail." *Magnetometer Requirements* P90: "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." *** P 91: 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).	Requirement R12 obligates responsible Planning Coordinators and Transmission Planners to implement a process to obtain geomagnetic field data for its Planning Coordinator's planning area. Sources of geomagnetic field data include government observatories, installed equipment owned or operated by the entity, and third-party sources. Entities are referred to INTRAMAGNET guidance for criteria and considerations including data sampling rate (10-s or faster) and data format. By requiring responsible Planning Coordinators and Transmission Planners to obtain geomagnetic field data for their planning areas, the requirement ensures data is obtained from diverse geographic areas (latitudes and longitudes) of the North American Bulk-Power System.

#	P	Directive/Guidance	Resolution
		P 92: "[T]he 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."	
4)	**P 101, 102**	**REVISE TPL-007 TO REQUIRE DEADLINES FOR THE DEVELOPMENT AND COMPLETION OF CORRECTIVE ACTION PLANS** P 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." P 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 directive is addressed in proposed TPL-007-2 Requirement R7. Part 7.2 specifies that responsible entities must develop Corrective Action Plans (CAP) within one year of completing the benchmark GMD Vulnerability Assessment. Part 7.3 requires responsible entities to include a timetable in the CAP that must specify: • Implementation of non-hardware mitigation within two years of the development of the CAP; and • Implementation of hardware mitigation within four years of the development of the CAP. Part 7.4 provides responsible entities with flexibility to revise the CAP and timetables if situations beyond the control of the responsible entity prevent implementation of the CAP within the specified timetable. The provision is necessary to account for potential planning, siting, budgeting approval, or regulatory uncertainties associated with transmission system projects that are not within the responsible entity's control. Responsible entities are obligated to document the revised CAP and update the revised CAP every 12 calendar months until implemented.

#	P	Directive/Guidance	Resolution
			Requirement R8 requires responsible entities to complete a supplemental GMD Vulnerability Assessment, based on the supplemental GMD event, to evaluate localized enhancements of geomagnetic field during a severe GMD event that could potentially affect the reliable operation of the Bulk-Power System. Localized enhancements of geomagnetic field can result in geoelectric field values above the spatially-averaged benchmark in a local area. Part 8.3 specifies that if the responsible entity concludes that there is Cascading caused by the supplemental GMD event, then the responsible entity shall conduct an analysis of possible actions to reduce the likelihood or mitigate the impacts and the event. Proposed TPL-007-2 does not require responsible entities to implement a Corrective Action Plan to address impacts identified in the supplemental GMD Vulnerability Assessment because mandatory mitigation on the basis of the supplemental GMD Vulnerability Assessment may not provide effective reliability benefit or use industry resources optimally. As discussed in the Supplemental GMD Event Description white paper, the supplemental GMD event is based on a small number of observed localized enhancement events that provide only general insight into the geographic size of localized events during severe solar storms. Additionally, the state-of-the-art modeling tools do not provide entities with capabilities to realistically model localized enhancements within a severe GMD event, and as a result entities may need to employ conservative approaches in the GMD Vulnerability Assessment such as applying the localized peak geoelectric field over an

#	P	Directive/Guidance	Resolution
			entire planning area. The approach taken in TPL-007-2 to mitigating impacts identified in the supplemental GMD Vulnerability Assessment provides responsible entities with flexibility to consider and select actions based on entity-specific factors. This is similar to the approach taken in Reliability Standard TPL-001-4 for extreme events (TPL-001-4 Requirement R3 Part 3.5).

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2013-03 Geomagnetic Disturbance Mitigation
Reliability Standard TPL-007-2

Applicable Standard(s)

- TPL-007-2 - Transmission System Planned Performance for Geomagnetic Disturbance Events

Requested Retirement(s)

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

Prerequisite Standard(s)

None

Applicable Entities

- Planning Coordinator with a planning area that includes a Facility or Facilities specified in Section 4.2 of the standard;
- Transmission Planner with a planning area that includes a Facility or Facilities specified in Section 4.2 of the standard;
- Transmission Owner who owns a Facility or Facilities specified in Section 4.2 of the standard;
- Generator Owner who owns a Facility or Facilities specified in Section 4.2 of the standard.

Section 4.2 states that the standard applies to facilities that include power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV.

Terms in the NERC Glossary of Terms

There are no new, modified, or retired terms.

Background

On September 22, 2016, the Federal Energy Regulatory Commission (FERC) issued Order No. 830 approving Reliability Standard TPL-007-1 and its associated five-year Implementation Plan. In the Order, FERC also directed NERC to develop certain modifications to the standard. FERC established a deadline of 18 months from the effective date of Order No. 830 for completing the revisions, which is May 2018.

General Considerations

This Implementation Plan is intended to integrate the new requirements in TPL-007-2 with the GMD Vulnerability Assessment process that is being implemented through approved TPL-007-1. At the time of the May 2018 filing deadline, many requirements in approved standard TPL-007-1 that lead to completion of the GMD Vulnerability Assessment will be in effect. Furthermore, many entities

may be taking steps to complete studies or assessments that are required by future enforceable requirements in TPL-007-1. The Implementation Plan phases in the requirements in TPL-007-2 based on the effective date of TPL-007-2, as follows:

- **Effective Date before January 1, 2021**. Implementation timeline supports applicable entities completing new requirements for supplemental GMD Vulnerability Assessments concurrently with requirements for the benchmark GMD Vulnerability Assessment (concurrent effective dates).

- **Effective Date on or after January 1, 2021**. Implementation timeline supports applicable entities completing the benchmark GMD Vulnerability Assessments before new requirements for supplemental GMD Vulnerability Assessments become effective.

Effective Date and Phased-In Compliance Dates

The effective date for the proposed Reliability Standard is provided below. Where the standard drafting team identified the need for a longer implementation period for compliance with a particular section of a proposed Reliability Standard (e.g., an entire Requirement or a portion thereof), the additional time for compliance with that section is specified below. The phased-in compliance date for those particular sections represents the date that entities must begin to comply with that particular section of the Reliability Standard, even where the Reliability Standard goes into effect at an earlier date.

Standard TPL-007-2

Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is three (3) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

If TPL-007-2 becomes effective before January 1, 2021

Implementation timeline supports applicable entities completing new requirements for supplemental GMD Vulnerability Assessments concurrently with requirements for the benchmark GMD Vulnerability Assessment (concurrent effective dates).

Compliance Date for TPL-007-2 Requirement R9

Entities shall not be required to comply with Requirement R9 until six (6) months after the effective date of Reliability Standard TPL-007-2.

Compliance Date for TPL-007-2 Requirements R11 and R12
Entities shall not be required to comply with Requirements R11 and R12 until 24 months after the effective date of Reliability Standard TPL-007-2.

Compliance Date for TPL-007-2 Requirements R6 and R10
Entities shall not be required to comply with Requirements R6 and R10 until 30 months after the effective date of Reliability Standard TPL-007-2.

Compliance Date for TPL-007-2 Requirements R3, R4, and R8
Entities shall not be required to comply with Requirements R3, R4, and R8 until 42 months after the effective date of Reliability Standard TPL-007-2.

Compliance Date for TPL-007-2 Requirement R7
Entities shall not be required to comply with Requirement R7 until 54 months after the effective date of Reliability Standard TPL-007-2.

If TPL-007-2 becomes effective on or after January 1, 2021

Implementation timeline supports applicable entities completing the benchmark GMD Vulnerability Assessments before new requirements for supplemental GMD Vulnerability Assessments become effective.

Compliance Date for TPL-007-2 Requirements R3 and R4
Entities shall not be required to comply with Requirements R3 and R4 until 12 months after the effective date of Reliability Standard TPL-007-2.

Compliance Date for TPL-007-2 Requirements R7, R11, and R12
Entities shall not be required to comply with Requirements R7, R11, and R12 until 24 months after the effective date of Reliability Standard TPL-007-2.

Compliance Date for TPL-007-2 Requirement R9
Entities shall not be required to comply with Requirement R9 until 36 months after the effective date of Reliability Standard TPL-007-2.

Compliance Date for TPL-007-2 Requirement R10
Entities shall not be required to comply with Requirement R10 until 60 months after the effective date of Reliability Standard TPL-007-2.

Compliance Date for TPL-007-2 Requirement R8
Entities shall not be required to comply with Requirement R8 until 72 months after the effective date of Reliability Standard TPL-007-2.

Retirement Date

Standard TPL-007-1

Reliability Standard TPL-007-1 shall be retired immediately prior to the effective date of TPL-007-2 in the particular jurisdiction in which the revised standard is becoming effective.

Initial Performance of Periodic Requirements

Transmission Owners and Generator Owners are not required to comply with Requirement R6 prior to the compliance date for Requirement R6, regardless of when GIC flow information specified in Requirement R5 Part 5.1 is received.

Transmission Owners and Generator Owners are not required to comply with Requirement R10 prior to the compliance date for Requirement R10, regardless of when GIC flow information specified in Requirement R9 Part 9.1 is received.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Screening Criterion for Transformer Thermal Impact Assessment

Project 2013-03 (Geomagnetic Disturbance Mitigation)

TPL-007-~~1~~2 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).~~

Proposed TPL-007-2 includes requirements for entities to perform two types of GMD Vulnerability Assessments to evaluate the potential impacts of GMD events on the Bulk Electric System (BES):

- The benchmark GMD Vulnerability Assessment is based on the benchmark GMD event associated with TPL-007-1 which was approved by the Federal Energy Regulatory Commission (FERC) in Order No. 830 in September 2016. The benchmark GMD event is derived from spatially-averaged geoelectric field values to address potential wide-area effects that could be caused by a severe 1-in-100 year GMD event.[1]
- The supplemental GMD Vulnerability Assessment, based on the supplemental GMD event, is used by entities to evaluate risks that localized peaks in geomagnetic field during a severe GMD event "could potentially affect the reliable operation of the Bulk-Power System".[2] Localized enhancements of geomagnetic field can result in geoelectric field values above the spatially-averaged benchmark in a local area.

[1] See *Benchmark Geomagnetic Disturbance Event Description* white paper, May 12, 2016. Filed by NERC in RM15-11 on June 28, 2016.

[2] See Order No. 830 P. 47. On September 22, 2016, FERC directed NERC to develop modifications to the benchmark GMD event, included in TPL-007-1, such that assessments would not be based solely on spatially averaged data. The characteristics of a GMD event for this assessment are in the Supplemental GMD Event Description white paper.

The standard requires transformer thermal impact assessments to be performed on BES power transformers with high side, wye-grounded windings with terminal voltage greater than 200 kV. Identified BES transformers must undergo a thermal impact assessment if the maximum effective geomagnetically-induced current (GIC) in the transformer is equal to or greater than:

- 75 A per phase for the benchmark GMD event
- 85 A per phase for the supplemental GMD event

Based on published power transformer measurement data as described below, the respective screening criteria are conservative and, although derived from measurements in single-phase units, are applicable to transformers with all core types (e.g., three-limb, three-phase).

Outside of the differing screening criteria, the only difference between the thermal impact assessment for the benchmark GMD event and the supplemental GMD event is that a different waveform is used, therefore peak metallic hot spot temperatures are slightly different for a given GIC in the transformer.

Justification for the Benchmark Screening Criterion

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~~waveform 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].

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

where

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

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

$$GIC(t) = E_E(t) \cdot GIC_E + E_N(t) \cdot GIC_N \quad (4)$$

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~~/~~ per V/km.

It should be emphasized that with the thermal models used and the benchmark GMD event geomagnetic field ~~waveshape~~waveform, peak metallic hot spot temperatures ~~must~~will lie below the envelope shown in black 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.

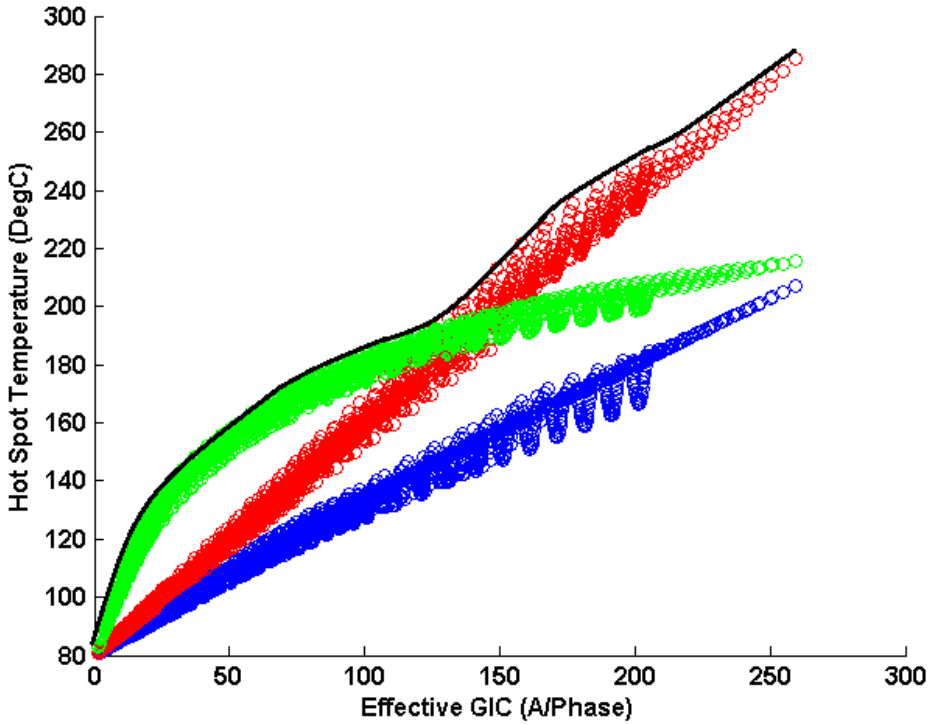


Figure 1: Metallic hot spot temperatures calculated using the benchmark GMD event. ~~Red: SVC coupling transformer model [2]. Blue: Fingrid model [3]. Green: Autotransformer model [4].~~ Red: SVC coupling transformer model [2]. Blue: Fingrid model [3]. Green: Autotransformer model [4].

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~~waveform 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).~~ Guide for Loading Mineral-Oil-Immersed Transformers and Step-Voltage Regulators [5].

~~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~~, which uses the most conservative thermal models known to date, indicates that a GIC of 75A will not result in peak metallic 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. Refer to IEEE Standard C57.163-2015 Guide for Establishing Power Transformer Capability while under Geomagnetic Disturbances for additional information [6].
- 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~~waveform 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~~being applied as a screening criterion for 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.

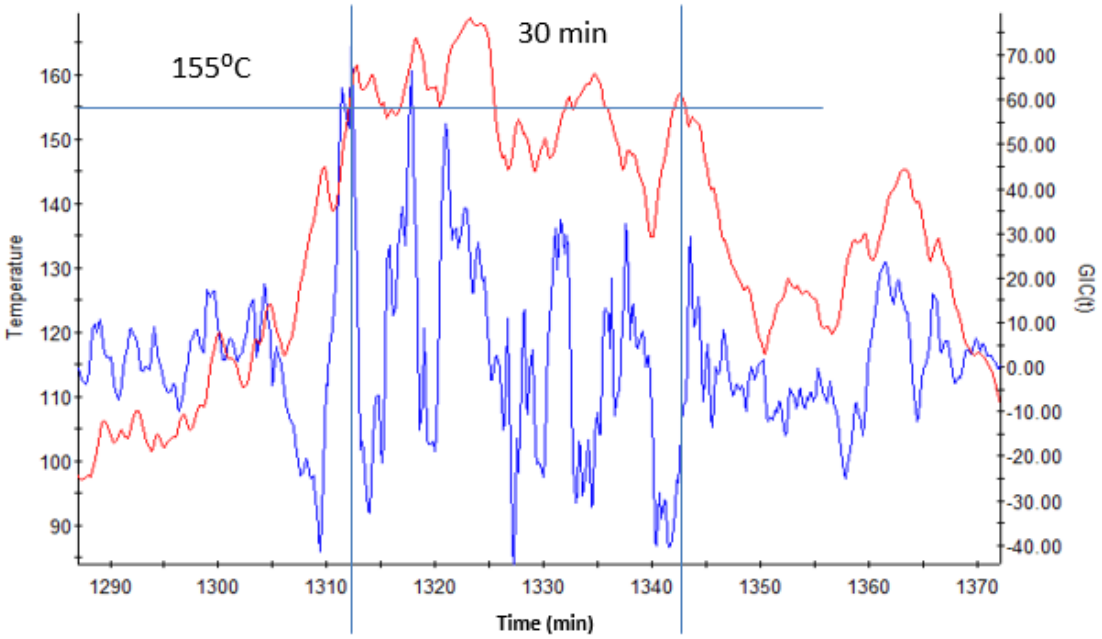


Figure 2: Metallic hot spot temperatures calculated using the benchmark GMD event. ~~Red: metallic hot spot temperature. Blue: GIC(t) that produces the maximum hot spot temperature with peak GIC(t) scaled to 75 A/phase.~~

Red: metallic hot spot temperature. Blue: GIC(t) that produces the maximum hot spot temperature with peak GIC(t) scaled to 75 A/phase.

Justification for the Supplemental Screening Criterion

As in the case for the benchmark GMD event discussed above, applicable entities are required to carry out thermal assessments on their BES power transformers when the effective GIC values are above a screening threshold. GIC(t) for supplemental thermal assessments is calculated using the supplemental GMD event geomagnetic field time series or waveform.

Using the supplemental GMD event waveform, a thermal analysis was completed for the two transformers that were limiting for the benchmark waveform. The results are shown in **Figure 3.** Peak metallic hot spot temperatures for the supplemental GMD event will lie below the envelope shown by the black line trace in **Figure 3**. Because the supplemental waveform has a sharper peak, the peak metallic hot spot temperatures are slightly lower than those associated with the benchmark waveform. Applying the most conservative thermal models known at this point in time, the peak metallic hot spot temperature obtained with the supplemental GMD event waveform assuming an effective GIC magnitude of 85 A per phase will result in a peak temperature of 172°C when the bulk oil temperature is 80°C (full load bulk oil temperature).[3] Thus, 85 A per phase is the screening level for the supplemental waveform.

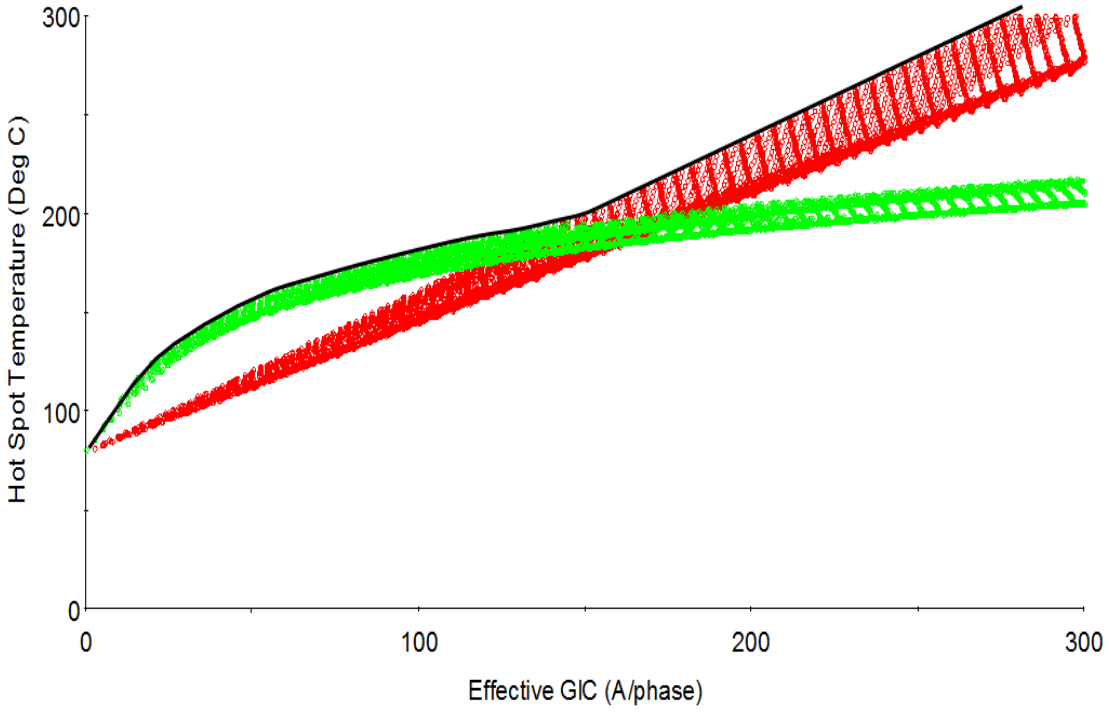


Figure 3: Metallic hot spot temperatures calculated using the supplemental GMD event.
Green: SVC coupling transformer model [2]. Red: Autotransformer model [4]

[3] The temperature 172°C was selected as the screening criteria for the benchmark waveform as described in the preceding section.

Appendix I - Transformer Thermal Models Used in the Development of the Screening Criteria

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~~I-1**). 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~~I-2 and ~~5~~I-3**), 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~~I-4 and ~~7~~I-5**). 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.

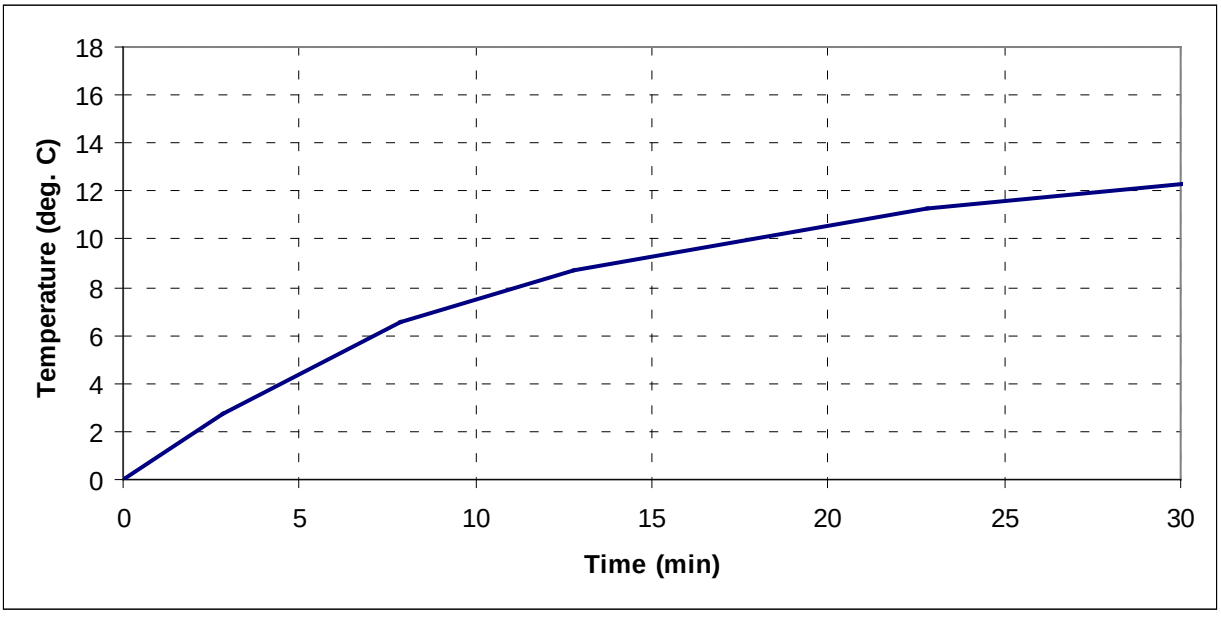


Figure ~~3:~~ I-1: Thermal step response of the tie plate of a 500 kV 400 MVA single-phase SVC coupling transformer to a 5 A per phase dc step.

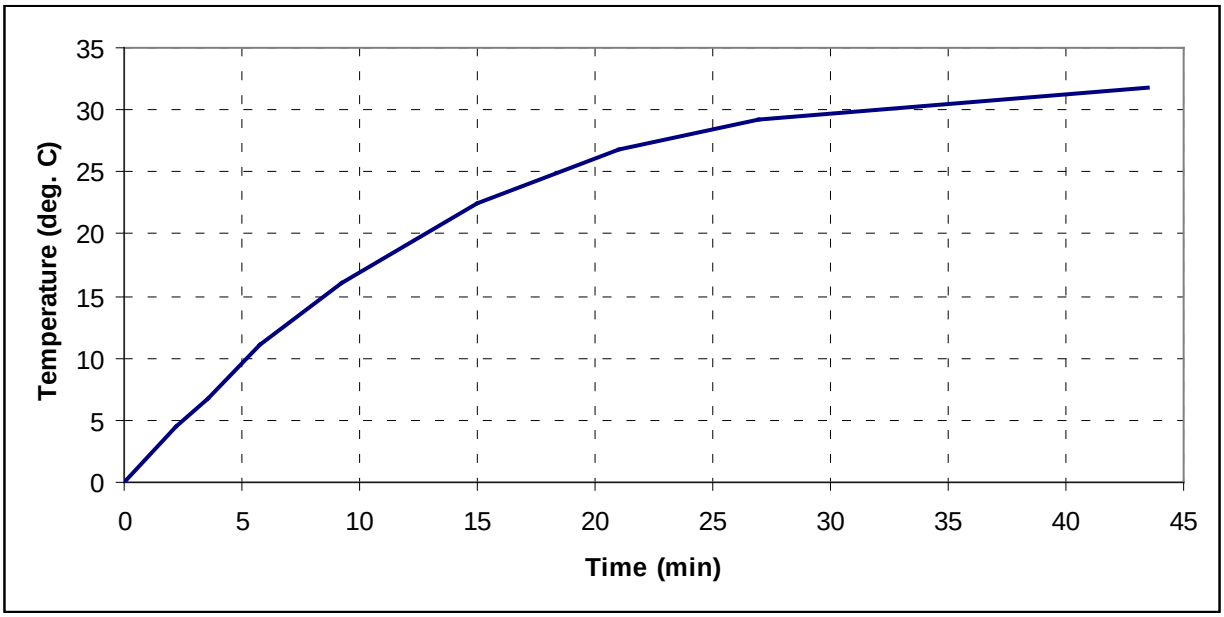


Figure 4I-2: Step thermal response of the top yoke clamp of a 400 kV 400 MVA five-leg core-type fully-wound transformer to a 16.67 A per phase dc step.

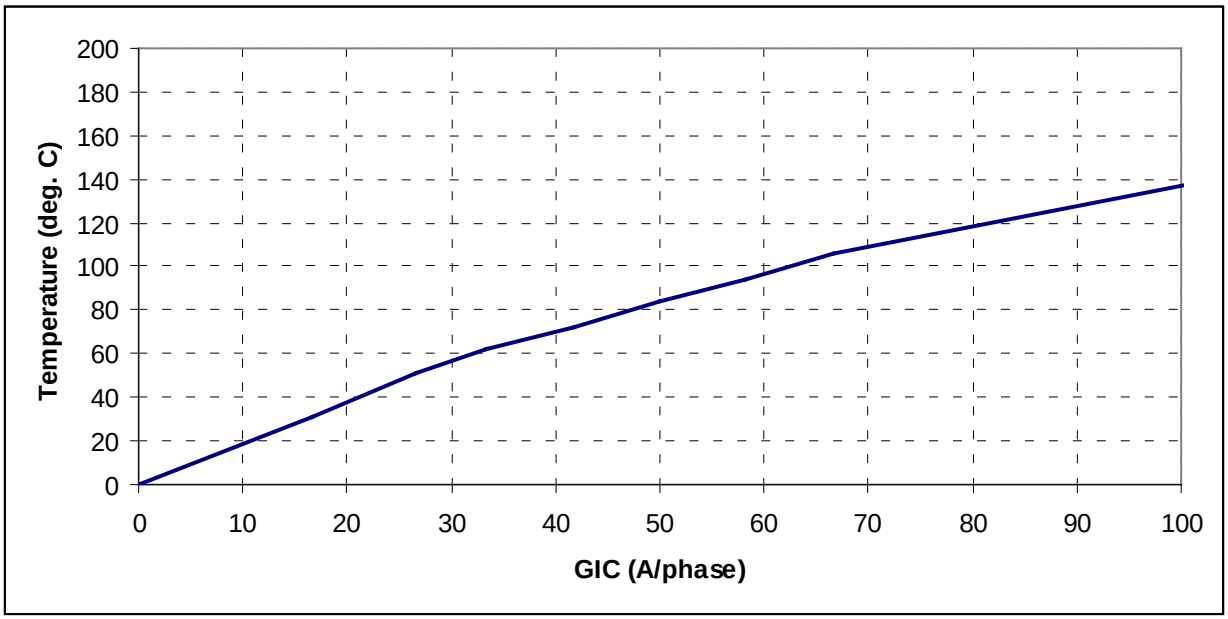
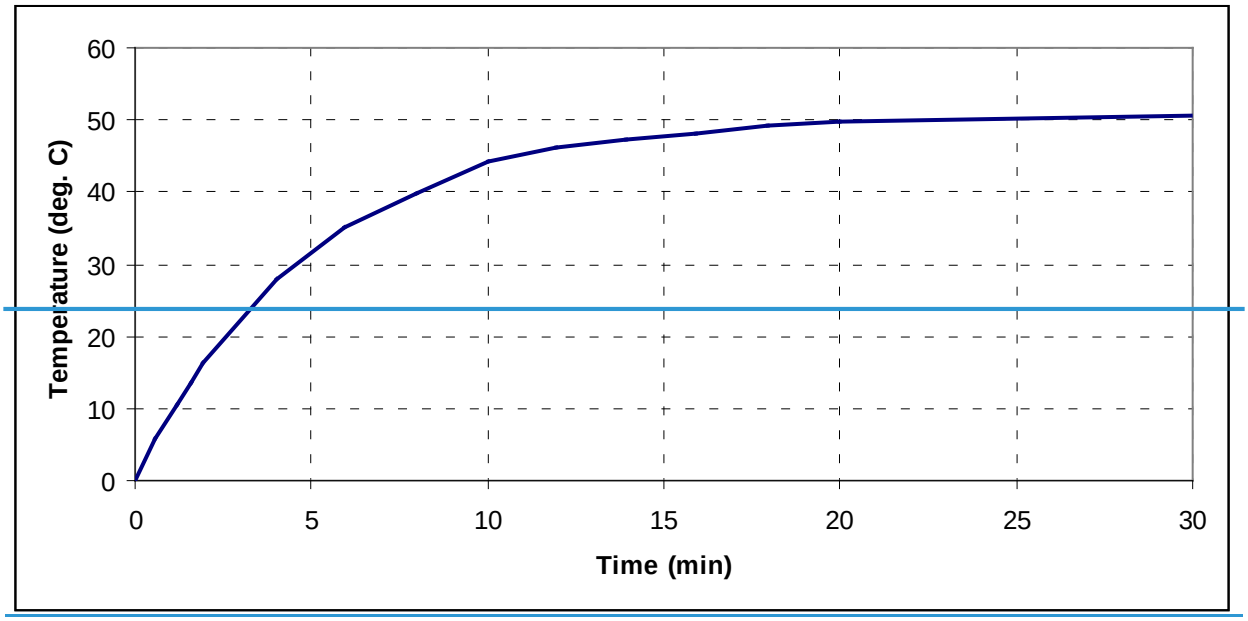


Figure ~~5:~~ I-3: Asymptotic thermal response of the top yoke clamp of a 400 kV 400 MVA five-leg core-type fully-wound transformer.



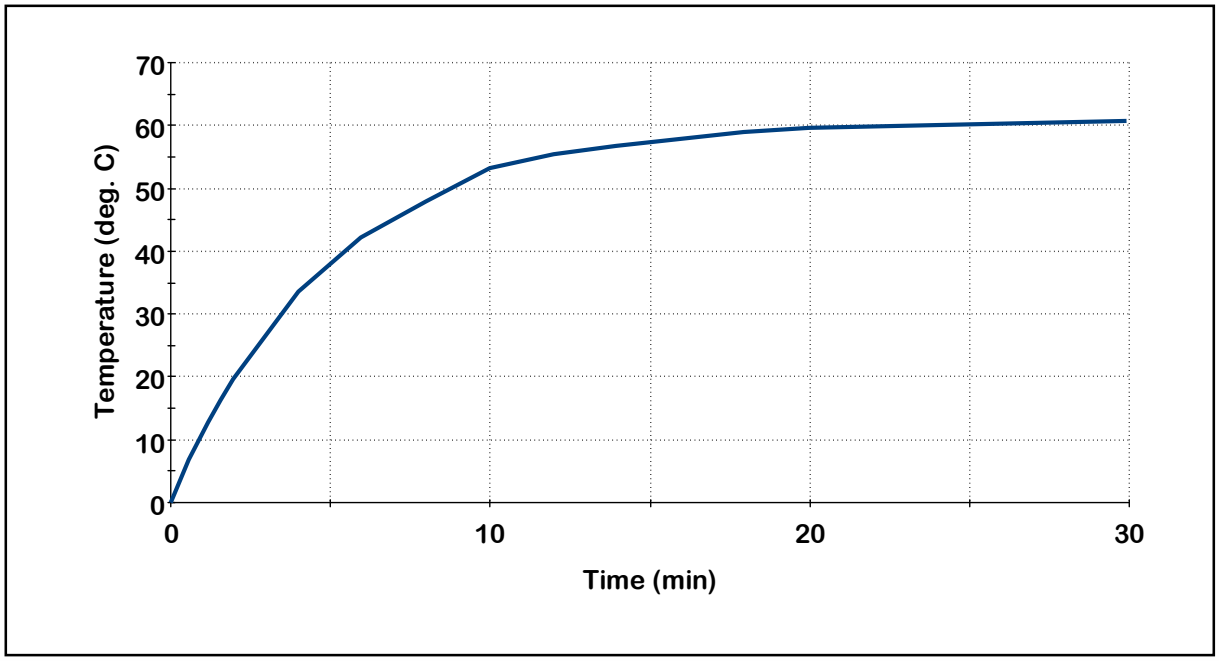


Figure ~~6~~I-4: Step thermal response of the tie plate of a 400 kV 400 MVA single-phase core-type autotransformer to a 10 A per phase dc step.

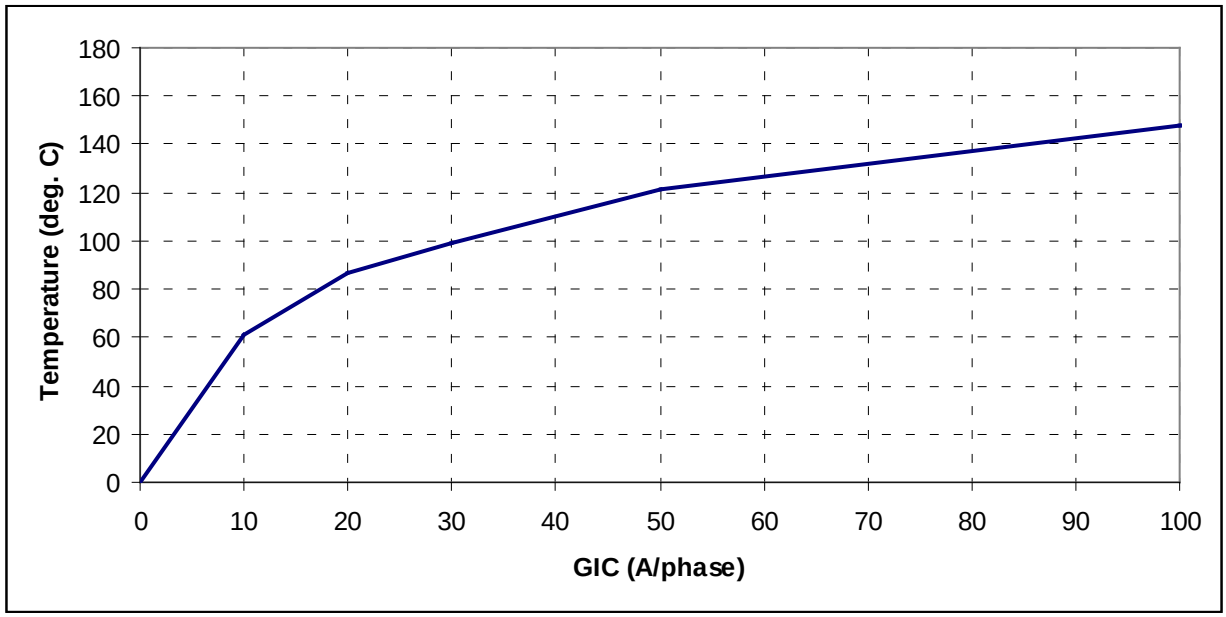


Figure ~~7~~1-5: Asymptotic thermal response of the tie plate of a 400 kV 400 MVA single-phase core-type autotransformer.

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

Table ~~2~~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

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.

Similar to the discussion above, the envelope in **Figure 3** can be used as a conservative thermal assessment for effective GIC values of associated with the supplemental waveform (see **Table 2**). Because the supplemental waveform has a sharper peak, the peak metallic hot spot temperatures associated with the supplemental waveform are slightly lower than those associated with the benchmark waveform. Comparing **Tables 1 and 2** shows the magnitude of this difference.

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

Effective GIC (A/phase)	Metallic hot spot Temperature (°C)	Effective GIC(A/phase)	Metallic hot spot Temperature (°C)
0	80	120	188
10	107	130	191
20	124	140	194
30	137	150	198
40	147	160	203
50	156	170	209
60	161	180	214
70	162	190	229
75	165	200	237
80	169	220	248
85	172	230	253
90	177	250	276

100	181	275	298
110	185	300	316

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~~http://www.nerc.com/pa/stand/Pages/TPL0071RI.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]~~ [5] "IEEE Guide for ~~loading mineral-oil-immersed transformers~~Loading Mineral-Oil-Immersed Transformers and ~~step-voltage regulators~~Step-Voltage Regulators." IEEE Std C57.91-2011 (Revision of IEEE Std C57.91-1995).

[6] "IEEE Guide for Establishing Power Transformer Capability while under Geomagnetic Disturbances." IEEE Std C57.163-2015.

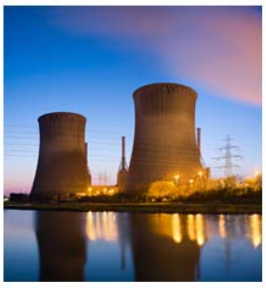
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Supplemental Geomagnetic Disturbance Event Description

Project 2013-03 GMD Mitigation

June 2017

RELIABILITY | ACCOUNTABILITY



3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

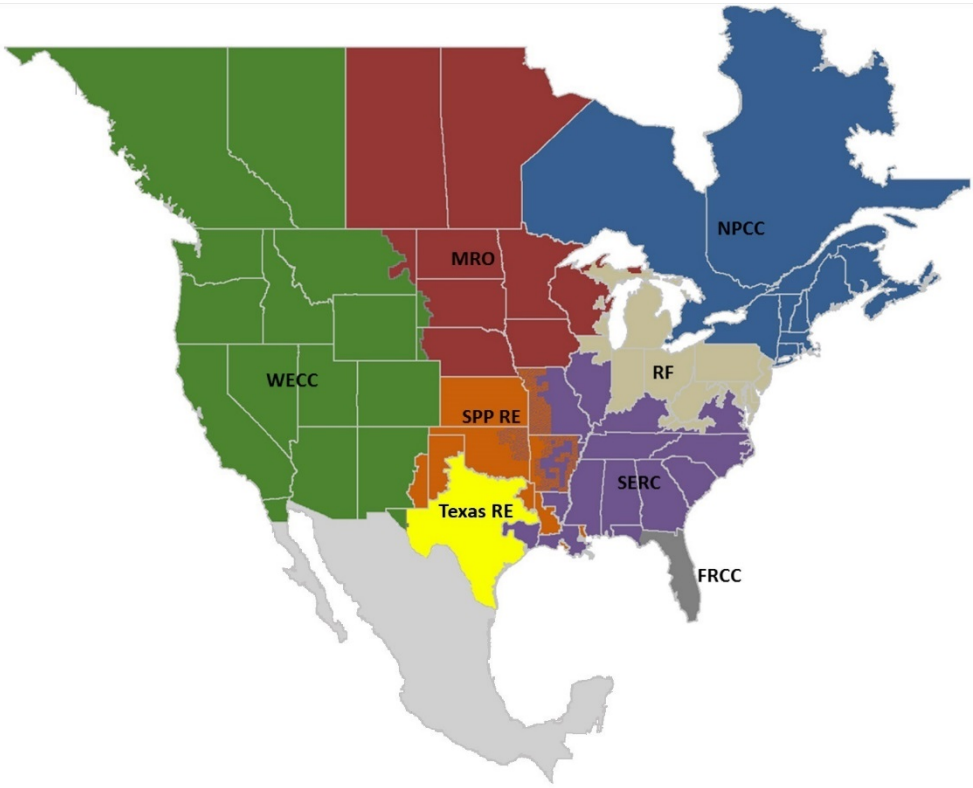
Table of Contents

Preface iii
Introduction iv
Background iv
General Characteristics iv
Supplemental GMD Event Description 1
Supplemental GMD Event Geoelectric Field Amplitude 1
Supplemental Geomagnetic Field Waveform 1
Appendix I – Technical Considerations 3
Statistical Considerations 3
Extreme Value Analysis 4
Spatial Considerations 7
Local Enhancement Waveform 13
Transformer Thermal Assessment 15
Appendix II – Scaling the Supplemental GMD Event 16
Scaling the Geomagnetic Field 16
Scaling the Geoelectric Field 18
References 22

Preface

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

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



The North American BPS is divided into eight RE boundaries. The highlighted areas denote overlap as some load-serving entities participate in one Region while associated transmission owners/operators participate in another.

FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
SPP RE	Southwest Power Pool Regional Entity
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Introduction

Background

Proposed TPL-007-2 includes requirements for entities to perform two types of GMD Vulnerability Assessments to evaluate the potential impacts of GMD events on the Bulk Electric System (BES):

- The benchmark GMD Vulnerability Assessment is based on the benchmark GMD event associated with TPL-007-1 which was approved by the Federal Energy Regulatory Commission (FERC) in Order No. 830 in September 2016. The benchmark GMD event is derived from spatially-averaged geoelectric field values to address potential wide-area effects that could be caused by a severe 1-in-100 year GMD event.[1]
- The supplemental GMD Vulnerability Assessment, based on the supplemental GMD event described in this white paper, is used by entities to evaluate localized enhancements of geomagnetic field during a severe GMD event that "could potentially affect the reliable operation of the Bulk-Power System".[2] Localized enhancements of geomagnetic field can result in geoelectric field values above the spatially-averaged benchmark in a local area.

The purpose of the supplemental geomagnetic disturbance (GMD) event description is to provide a defined event for assessing system performance for a GMD event which includes a local enhancement of the geomagnetic field. In addition to varying with time, geomagnetic fields can be spatially non-uniform with higher and lower strengths across a region. This spatial non-uniformity has been observed in a number of GMD events, so localized enhancement of field strength above the average value is considered. The supplemental GMD event defines the geomagnetic and geoelectric field values used to compute geomagnetically-induced current (GIC) flows for a supplemental GMD Vulnerability Assessment.

General Characteristics

The supplemental GMD event described herein takes into consideration observed characteristics of a local geomagnetic field enhancement, recognizing that the science and understanding of these events is evolving. Based on observations and initial assessments, the characteristics of local enhancements include:

- Geographic area – The extent of local enhancements is on the order of 100km in North-South (latitude) direction but longer in East-West (longitude) direction. Further description of the geographic area is provided later in the white paper.
- Amplitude – The amplitude of the resulting geoelectric field is significantly higher than the geoelectric field that is calculated in the spatially-averaged Benchmark GMD event.
- Duration – The local enhancement in the geomagnetic field occurs over a time period of 2-5 minutes.
- Geoelectric field waveform – The supplemental GMD event waveform is the benchmark GMD event waveform with the addition of a local enhancement. The added local enhancement has amplitude and duration characteristics described above. The geoelectric field waveform 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 rate of change of the magnetic field (dB/dt) is a function of the waveform, which in turn has a direct effect on the geoelectric field since the earth response to dB/dt is frequency-dependent. As with the benchmark GMD event, the supplemental GMD event waveform is based on magnetic field data recorded by the Natural Resources Canada (NRCan) Ottawa (OTT) geomagnetic observatory during the March 13-

[1] See *Benchmark Geomagnetic Disturbance Event Description* white paper, May 12, 2016. Filed by NERC in RM 15-11 on June 28, 2016.

[2] See Order No. 830 P. 47. On September 22, 2016, FERC directed NERC to develop modifications to the benchmark GMD event, included in TPL-007-1, such that assessments would not be based solely on spatially averaged data.

14 1989 event. This GMD event data was selected because analysis of recorded events indicates that the OTT observatory data for this period provides conservative results when performing thermal assessments of power transformers.[3]

[3] See *Benchmark Geomagnetic Disturbance Event Description* white paper, page 5 and Appendix I.

Supplemental GMD Event Description

Severe geomagnetic disturbance events are high-impact, low-frequency (HILF) events [1]; thus, GMD events used in system planning should consider the probability that the event will occur, as well as the impact or consequences of such an event. The supplemental GMD 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 waveform to facilitate time-domain analysis of GMD impact on equipment.

Supplemental GMD Event Geoelectric Field Amplitude

The supplemental GMD event field amplitude was determined through statistical analysis using the plane wave method [2]-[9] of geomagnetic field measurements from geomagnetic observatories in northern Europe [10] and the reference (Quebec) earth model shown in **Table 1** [11], supplemented by data from Greenland, Denmark and Alaska. 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 I) resulted in conservative peak geoelectric field amplitude of approximately 12 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 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 12 V/km using the following relationship

$$E_{peak} = 12 \times \alpha \times \beta_S \text{ (V/km)} \quad (1)$$

where α is the scaling factor to account for local geomagnetic latitude, and β_S is a scaling factor for the supplemental GMD event to account for the local earth conductivity structure (see Appendix II).

Supplemental Geomagnetic Field Waveform

The supplemental geomagnetic field waveform is the benchmark geomagnetic field waveform with the addition of a local enhancement. Both the benchmark and supplemental geomagnetic field waveforms are used to calculate the GIC time series, GIC(t), required for transformer thermal impact assessments. The supplemental waveform includes a local enhancement, inserted at UT 1:18 March 14 in **Figure 1** below. This time corresponds to the largest calculated geoelectric fields during the benchmark GMD event. The amplitude of the local enhancement is based on a statistical analysis of a number of GMD events, discussed in Appendix I**.** The duration of the enhancement is based on the characteristics of observed localized enhancements as discussed in Appendix I.

The geomagnetic latitude of the Ottawa geomagnetic observatory is 55°; therefore, the amplitude of the geomagnetic field measurement data with a local enhancement was 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 12 V/km (see **Figure 2**). Sampling rate for the geomagnetic field waveform is 10 seconds.

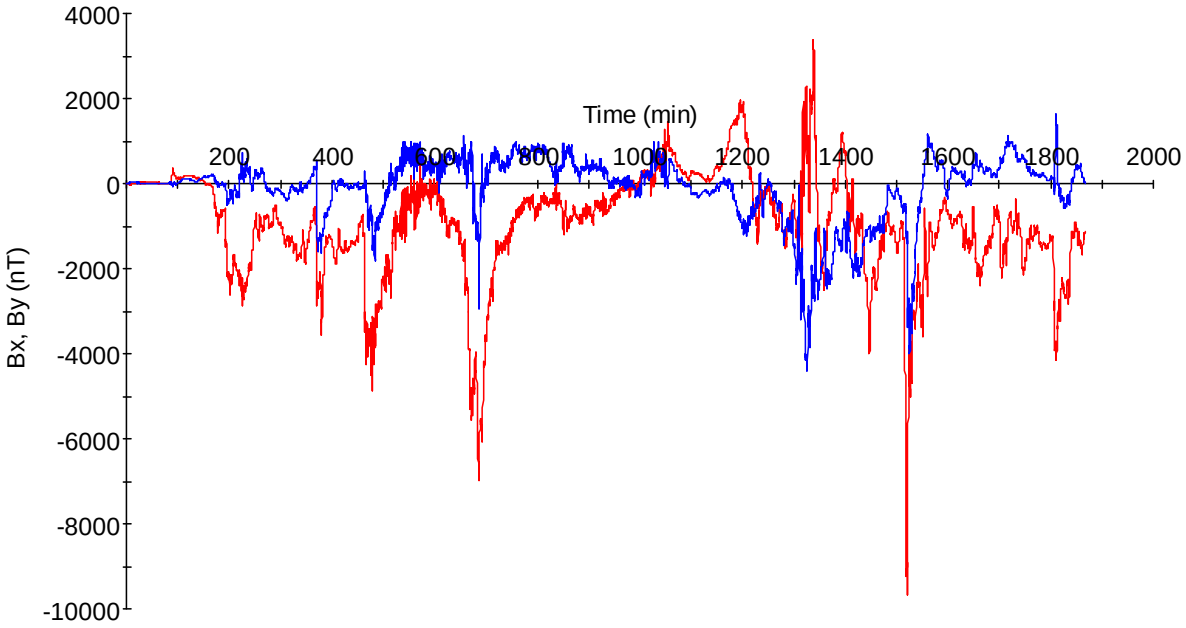


Figure 1: Supplemental Geomagnetic Field Waveform
Red B_x (Northward), Blue B_y (Eastward),
Referenced to pre-event quiet conditions

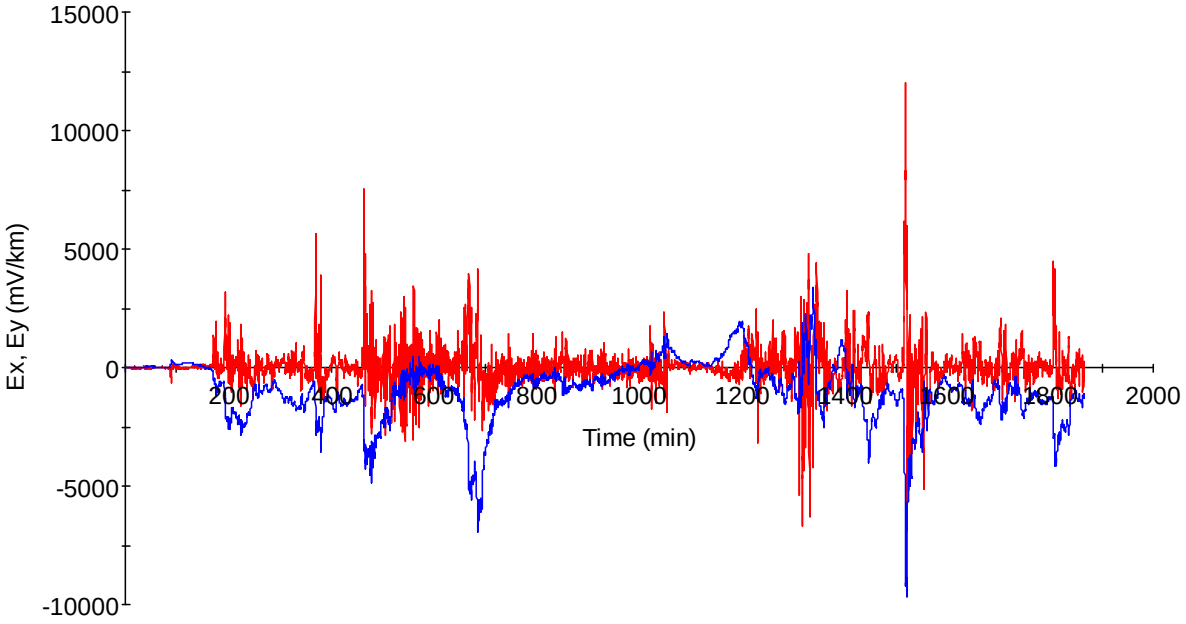


Figure 2: Supplemental Geoelectric Field Waveform
Red E_y (Eastward), Blue E_x (Northward)

Appendix I – Technical Considerations

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

Statistical Considerations

The peak geoelectric field amplitude of the supplemental GMD event was determined through statistical analysis of modern 10-second geomagnetic field data and corresponding calculated geoelectric field amplitudes. The objective of the analysis was to estimate the geoelectric field amplitude that is associated with a 1 in 100 year frequency of occurrence. The same data set and similar statistical techniques were used in determining the peak geoelectric field amplitude of the benchmark GMD event, including extreme value analysis discussed in the following section.[4] The fundamental difference in the supplemental GMD event amplitude is that it is based on observations taken at each individual station (i.e., localized measurements), in contrast with the spatially averaged geoelectric fields used in the *Benchmark Geomagnetic Disturbance Event Description* white paper.[5]

[4] See *Benchmark Geomagnetic Disturbance Event Description* white paper, Appendix I, pages 8-13.

[5] Averaging the geoelectric field values of stations in geographic groups is referred to as spatial averaging in the *Benchmark Geomagnetic Disturbance Event Description.* Spatial averaging was used to characterize GMD events over a geographic area relevant to the interconnected transmission system for purposes of assessing area effects such as voltage collapse and widespread equipment risk. See *Benchmark Geomagnetic Disturbance Event Description* white paper, Appendix I, pages 9-10.

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% confidence interval of the maximum geoelectric field amplitude to be expected within a 100-year return period.[6]

The data set consists of 23 years of daily maximum geoelectric field amplitudes derived from individual stations in the IMAGE magnetometer chain, using the Quebec earth model as a reference. **Figure I-1** shows a scatter plot of geoelectric field amplitudes that exceed 2 V/km across the IMAGE stations. The plot indicates that there is seasonality in extreme observations associated with the 11-year solar cycle.

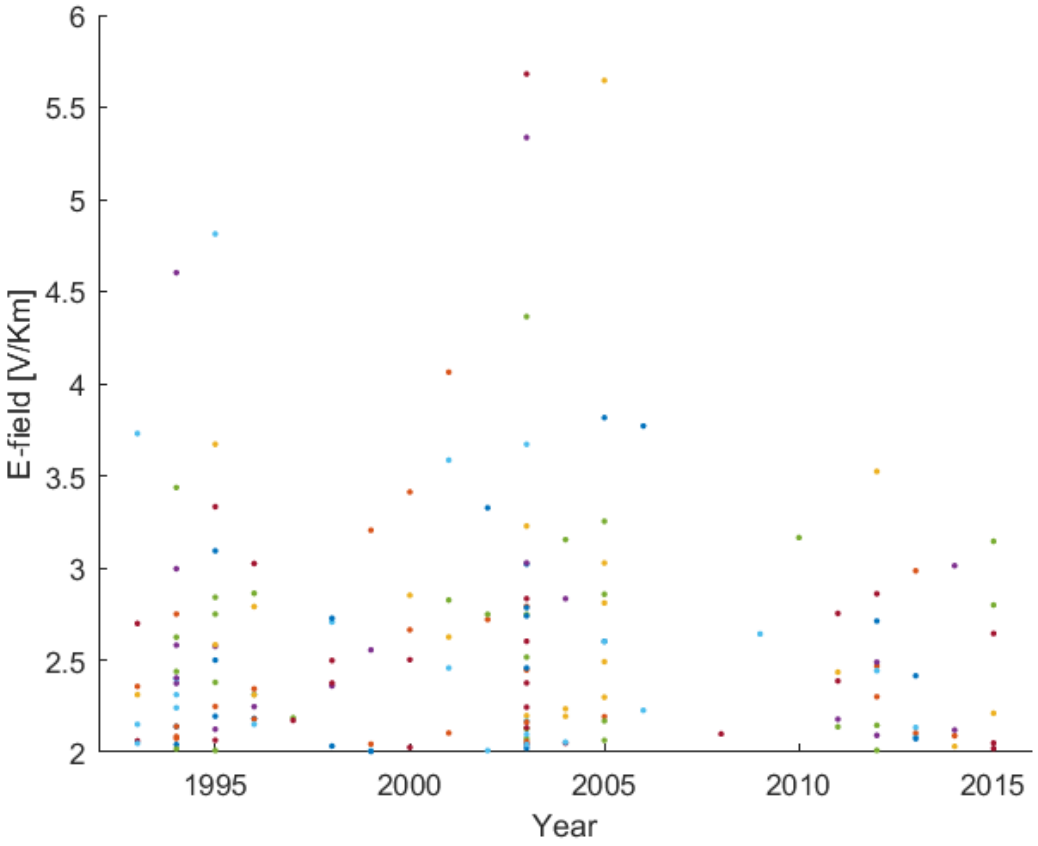


Figure I-1: Scatter Plot of Geoelectric Fields that Exceed a 2 V/km Threshold
Data source: IMAGE magnetometer chain from 1993-2015.

[6] 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.

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 [12].

Table I-1 shows a summary of the estimated parameters and return levels obtained from different statistical 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% confidence interval of the 100-year return level was calculated using the delta method and the profile likelihood. The delta method relies on the 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 Model	Estimated Parameters	Hypothesis Testing	100 Year Return Level Mean [V/km]	95% CI Delta [V/km]	95% CI P-Likelihood [V/km]
(1) GEV	μ=2.976 (0.193) σ=0.829 (0.1357) ξ=-0.0655 (0.1446)	H0: ξ=0 *p* = 0.66	6.9	[4.3, 8.2]	[5.2, 11.4]
(2) GEV, reparametrization $\mu = \beta_0 + \beta_1 \cdot \sin\left(\frac{t}{T} + \phi\right)$	β_0= 2.964 (0.151) β_1=0.582 (0.155) σ=0.627 (0.114) ξ=0.09 (0.183)	H0: β_1=0 *p* = 0.00 H0: ξ=0 *p* = 0.6	7.1	[4, 10.2]	[5.5, 18]
(3) POT, threshold=2 V/km 3 day decluster. 143 observations > 2V/km.	σ=0.592 (0.074) ξ=0.077 (0.093)		6.9	[4.5, 9.4]	[5.4, 11.9]
(4) POT, threshold=2V/km reparametrization, $\sigma = \beta_0 + \beta_1 \cdot \sin\left(\frac{t}{T} + \phi\right)$	β_0=0.58 (0.073) β_1=0.107 (0.082) ξ=0.037 (0.097)	H0: B1=0 *p* = 0.2	7	[4.6, 9.3]	[5.5, 11.7]

Statistical model (1) in **Table I-1** is the traditional GEV estimation using blocks of 1 year maxima; i.e., only 23 data points are used in the estimation. The mean expected amplitude of the geoelectric field for a 100-year return level is approximately 7 V/km. Since GEV works with blocks of maxima, it is typically regarded as a wasteful approach.

As discussed previously, GEV assumes that the data is iid. Based on the scatter plot shown in **Figure I-1**, the iid statistical assumption is not warranted by the data. Statistical model (2) in **Table I-1** is a reparametrization 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: $\beta_1=0$, is rejected with a p-value of 0.0032; as expected, the 11-year seasonality has explanatory power. The blocks of maxima during the solar minimum are better represented in the reparametrized GEV. The mean return level is still 7 V/km, but the confidence interval is wider, [5.5, 18] 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 2 V/km; the data was declustered 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; too low a threshold will likely lead to bias. On the other hand, too high a threshold will reduce the sample size and result in high variance. A threshold of 2V/km was determined to be a good choice, giving rise to 143 observations above the threshold.

The mean return level for statistical model (3), ~7 V/km, is consistent with the GEV estimates. However, due to the larger sample size the POT method is more efficient rendering a confidence interval of [5.4, 11.9] V/km for the profile likelihood method.

In an attempt to cope with potential heteroskedasticity in the data, a reparametrization of POT is proposed 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 not statistically significant; the null hypothesis, H0: $\alpha_1=0$, is not rejected with a p-value of 0.2. The proposed reparametrization does not have explanatory power, and consequently, the mean return level 7 V/km and confidence intervals remain virtually unchanged [5.5, 11.7]. As a final remark, it is emphasized that the confidence interval obtained using the profile likelihood is preferred over the delta method.

Figure I-2 shows the profile likelihood of the 100-year return level of statistical model (3). 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.

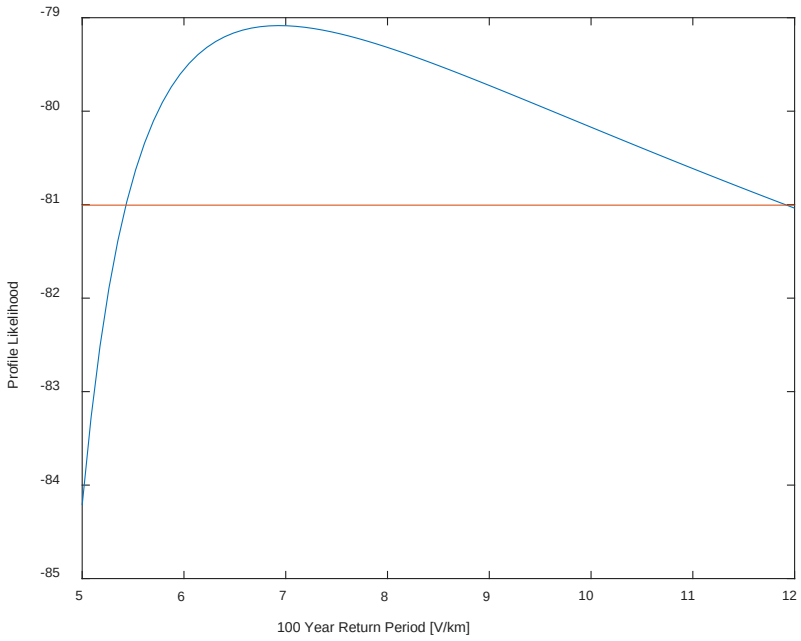


Figure I-2: Profile Likelihood for 100-year Return Level for Statistical Model (3)

To conclude, the traditional GEV (1) is misspecified; the statistical assumptions (iid) are not warranted by the data. The model was reparametrized to cope with seasonality in the data. Statistical models (3) and (4) better utilize the available extreme measurements and they are therefore preferred over statistical model (2). A geoelectric field amplitude of 12 V/km is selected for the supplemental GMD event to represent the upper limit of the 95 percent confidence interval for a 100-year return interval.

Spatial Considerations

The spatial structure of high-latitude geomagnetic fields can be very complex during strong geomagnetic storm events [13]-[14]. One reflection of this spatial complexity is localized geomagnetic field enhancements (local enhancements) that result in high amplitude geoelectric fields in regions of a few hundred kilometers. **Figure I-3** illustrates this spatial complexity of the storm-time geoelectric fields.[7] In areas indicated by the bright red location, the geoelectric field can be substantially larger than at neighboring locations. These enhancements are primarily the result of external (geomagnetic field) conditions, and not local geological factors such as coastal effects.[8]

[7] **Figure I-3** 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. The depiction is not to scale.

[8] Localized externally-driven geomagnetic phenomena should not be confused with localized geoelectric field enhancements due to complex electromagnetic response of the ground to external excitation. Complex 3D geological conditions such as those at coastal regions can lead to localized geoelectric field enhancements but those are not considered here.

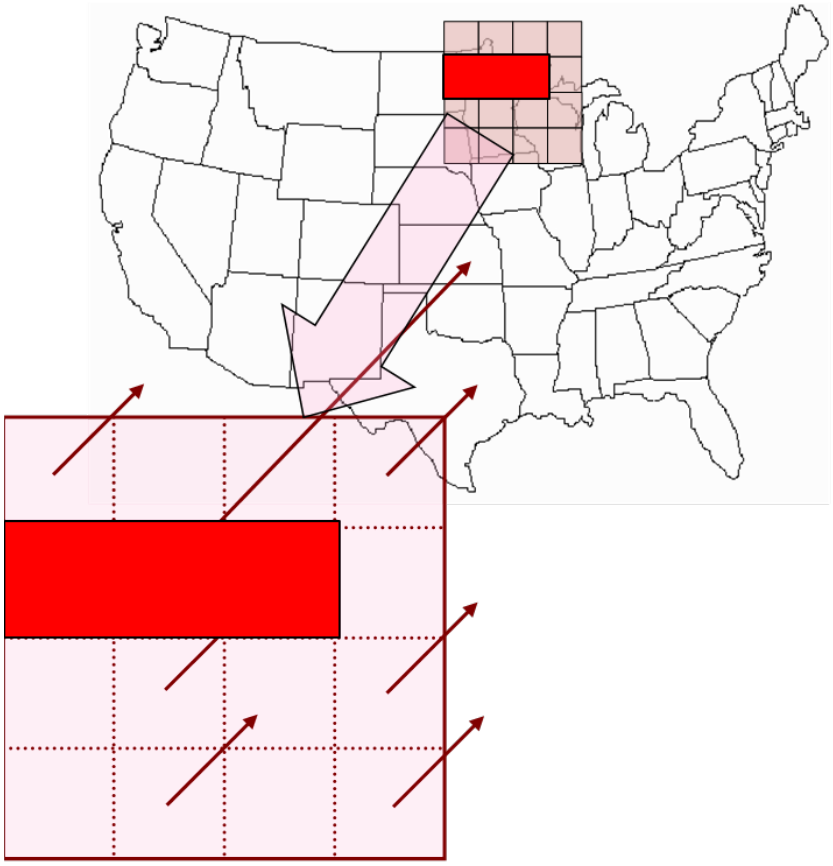


Figure I-3: Illustration of the Spatial Scale between Localized Enhancements and Larger Spatial Scale Amplitudes of Geoelectric Field during a Strong Geomagnetic Storm.
In this figure, the red rectangle illustrates a spatially localized field enhancement.

The supplemental GMD event is designed to address local effects caused by a severe GMD event, such as increased var absorption and voltage depressions.

A number of GMD events were analyzed to identify the basic characteristics of local enhancements. Three (3) solar storms studied and described below are:

- March 13, 1989
- October 29-30, 2003
- March 17, 2015

Four localized events within those storms were identified and analyzed. Geomagnetic field recordings were collected for these storms and the geoelectric field was computed using the 1D plane wave method and the reference Quebec ground model. In each case, a local enhancement was correlated, generally oriented parallel to the westward ionospheric electrojet associated with ongoing larger scale geomagnetic activity. (See **Figures I-4 – I-7** below)

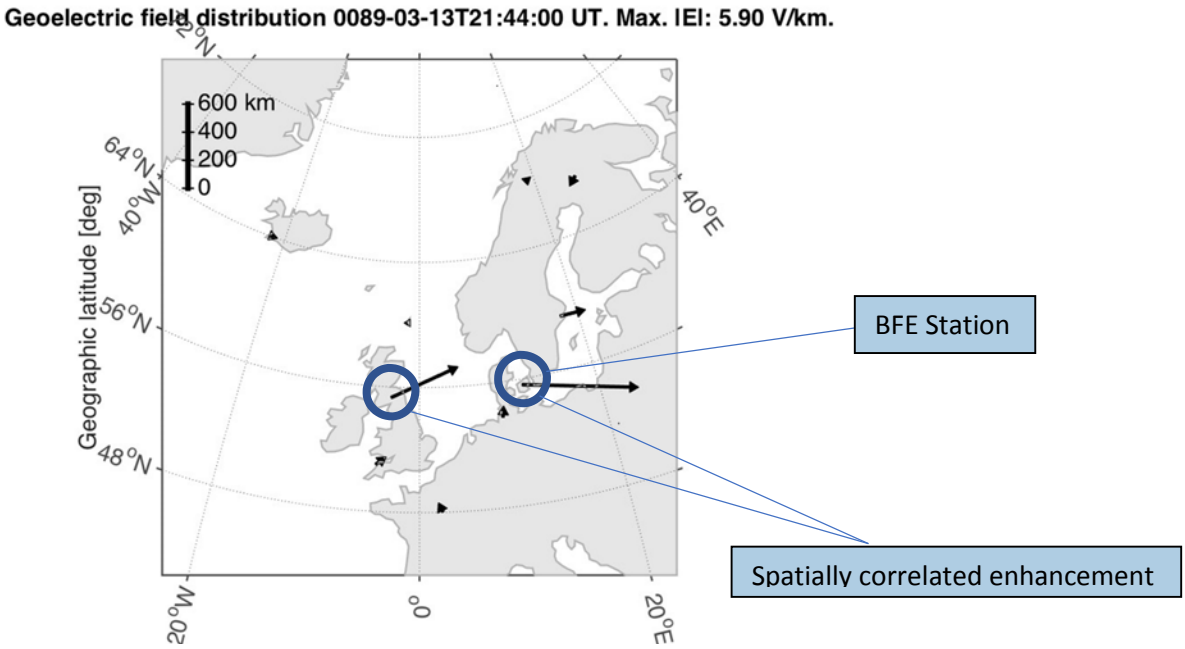


Figure I-4: March 13, 1989, at 21:44 UT, Brorfelde (BFE), Denmark

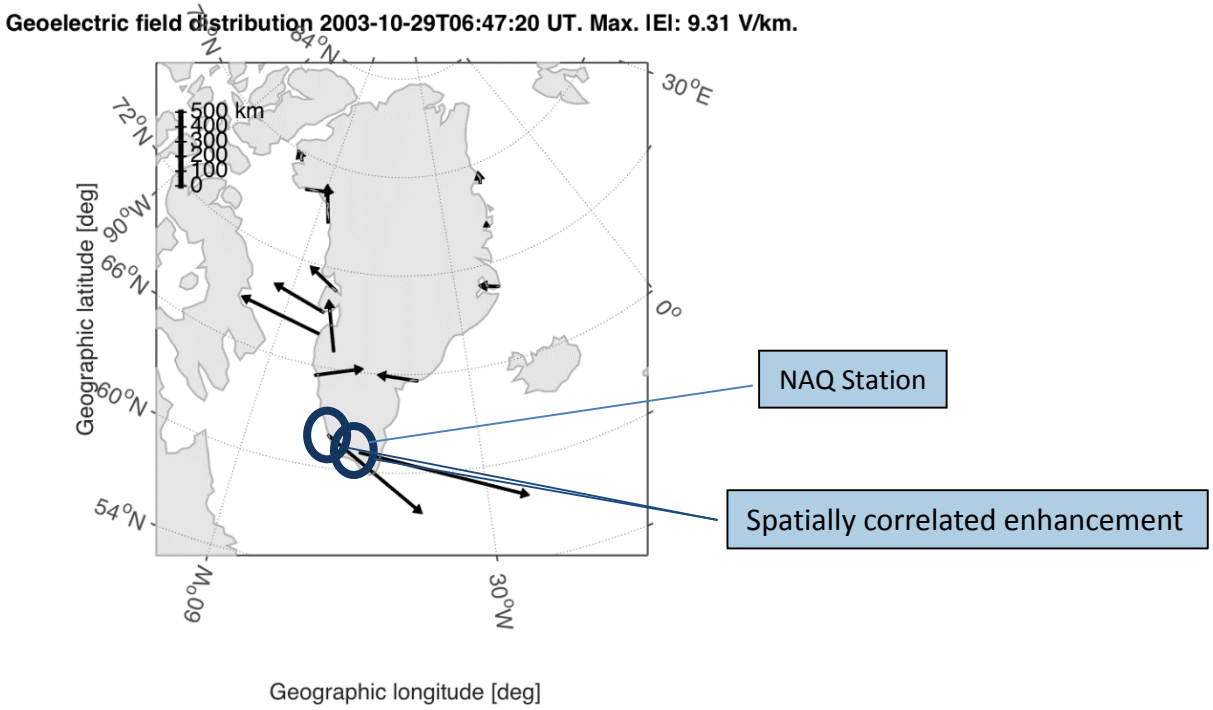


Figure I-5: October 29, 2003, at 06:47 UT, Narsarsuaq (NAQ), Greenland

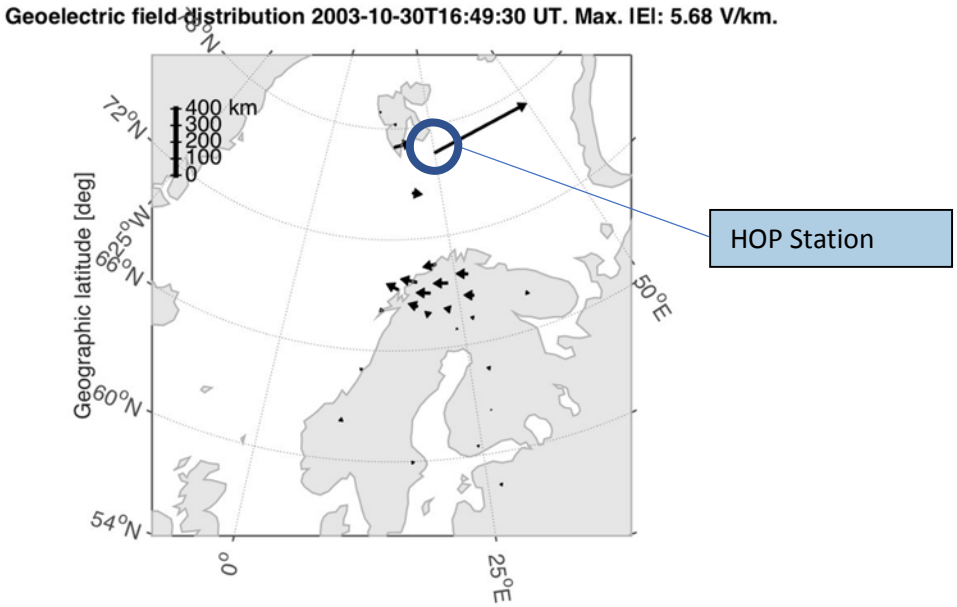


Figure I-6: October 30, 2003, at 16:49UT, Hopen Island (HOP), Svalbard, Norway

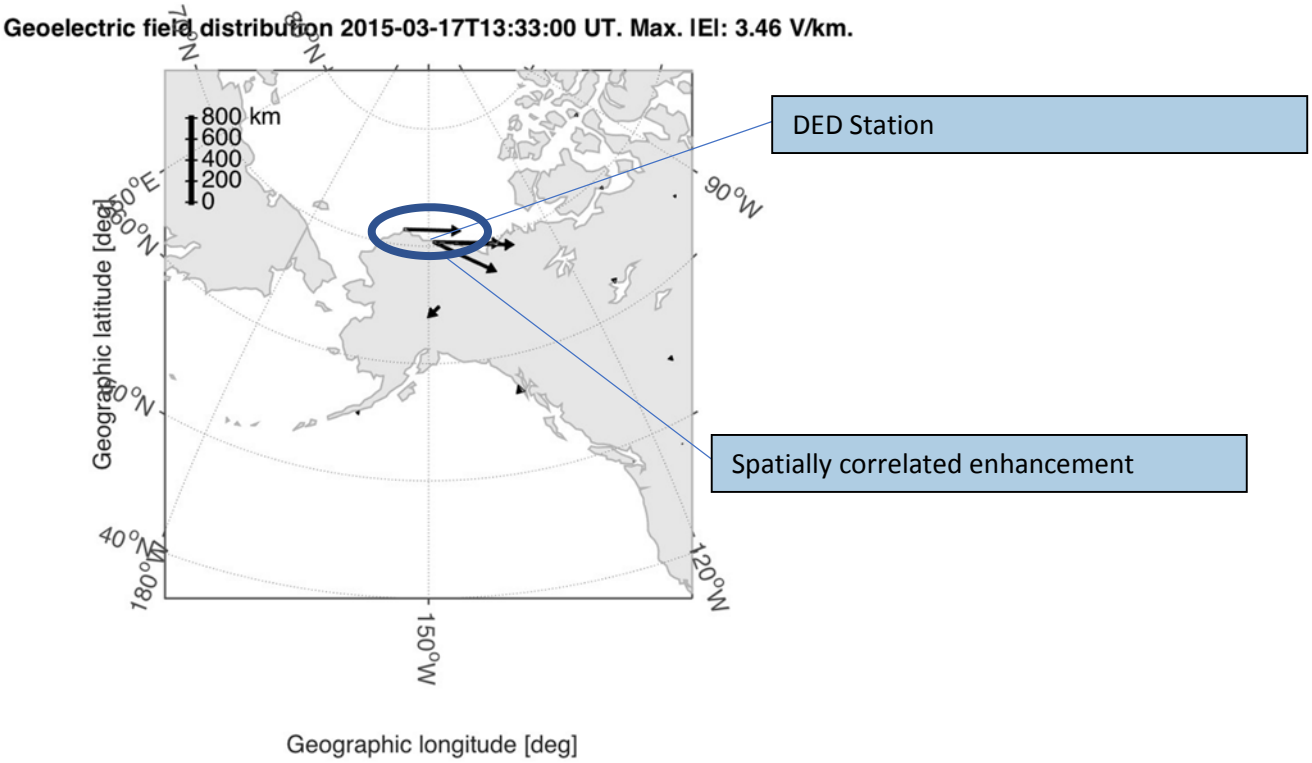


Figure I-7: March 17, 2015, at 13:33 UT, Deadhorse, Alaska

All of the above events were analyzed by reviewing the time series magnetic field data and transforming it to an electric field and focusing on the time period of the spatially correlated local enhancement. There were apparent similarities in the character of the local enhancements. The local enhancements occurred during peak periods of

geomagnetic activity and were distinguished by relatively brief excursions of rapid magnetic field variation. With respect to time duration, the local enhancements generally occurred over a period of 2-5 minutes. (See **Figures I-8 – I-11**)

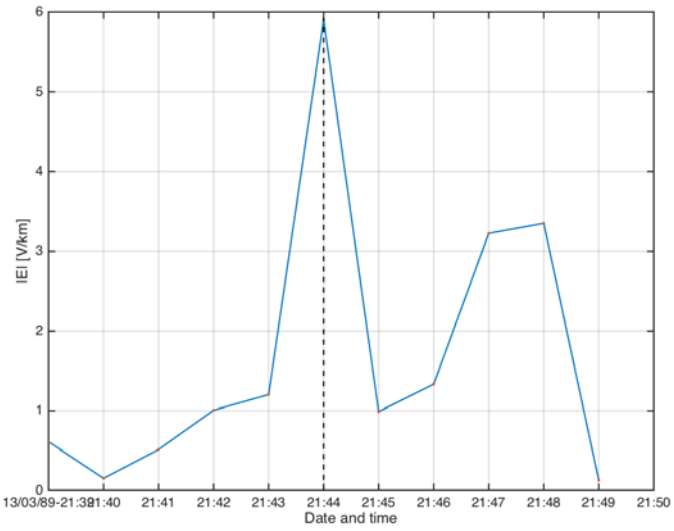


Figure I-8: Geoelectric field March 13, 1989, at 21:44 UT, Brorfelde (BFE), Denmark.

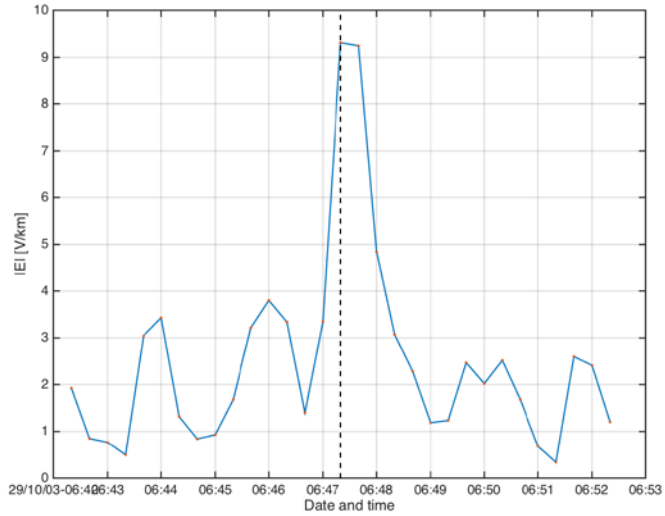


Figure I-9: Geoelectric field October 29, 2003, at 06:47 UT, Narsarsuaq (NAQ), Greenland

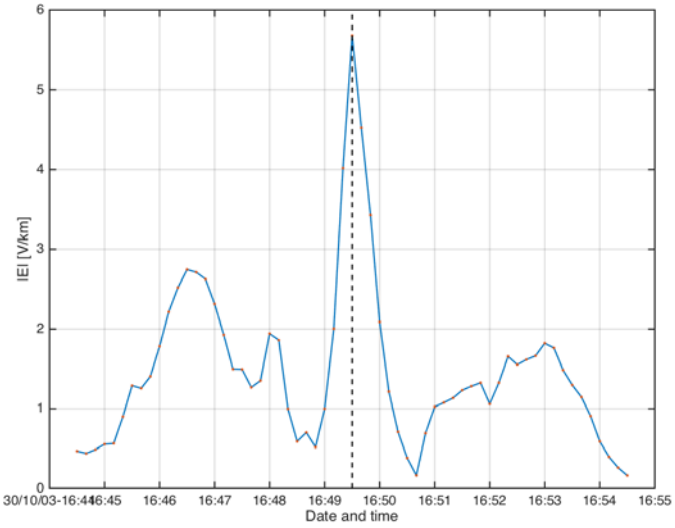


Figure I-10: Geoelectric field October 30, 2003, at 16:49UT, Hopen Island (HOP), Norway

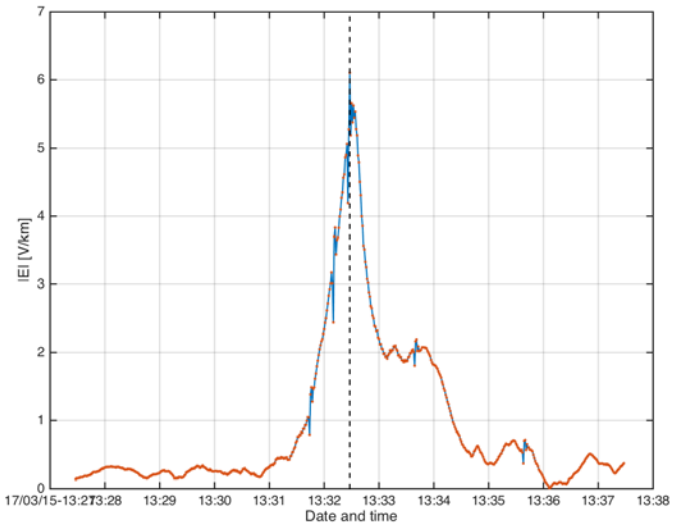


Figure I-11 – Geoelectric field March 17, 2015, at 13:33 UT, Deadhorse, Alaska

Based on the above analysis and the previous work associated with the benchmark GMD event, it is reasonable to incorporate a second (or supplemental) assessment into TPL-007 to account for the potential impact of a local enhancement in both the network analysis and the transformer thermal assessment(s).

With respect to geographic area of the localized enhancement, the historical geomagnetic field data analyzed so far provides some insight. Analysis suggests that the enhancements will occur in a relatively narrow band of geomagnetic latitude (on the order of 100 km) and wider longitudinal width (on the order of 500 km) as a consequence of the westward-oriented structure of the source in the ionosphere.

Proposed TPL-007-2 provides flexibility for planners to determine how to apply the supplemental GMD event to the planning area. Acceptable approaches include but are not limited to:

- Apply the peak geoelectric field for the supplemental GMD event (12 V/km scaled to the planning area) over the entire planning area;

- Apply a spatially limited (e.g., 100 km in North-South direction and 500 km in East-West direction) geoelectric field enhancement (12 V/km scaled to the planning area) over a portion(s) of the system, and apply the benchmark GMD event over the rest of the system.
- Other methods to adjust the benchmark GMD event analysis for localized geoelectric field enhancement.

Given the current state of knowledge regarding the spatial extent of a local geomagnetic field enhancements, upper geographic boundaries, such as the values used in the approaches above, are reasonable but are not definitive.

Local Enhancement Waveform

The supplemental geomagnetic field waveform was derived by modifying the benchmark GMD event waveform to emulate the observed events described above. The temporal location of the enhancement corresponds to the time of the benchmark event with the highest geoelectric field. The local enhancement was constructed by scaling linearly a 5-minute portion of the benchmark geomagnetic field so that the peak geoelectric field is 12 V/km at a geomagnetic latitude of 60° and reference earth model. **Figure I-12** shows the benchmark geomagnetic field and **Figure I-13** shows the supplemental event geomagnetic field. **Figure I-14** expands the view into B_x, with and without the local enhancement. **Figure I-15** is the corresponding expanded view of the geoelectric field magnitude with and without the local enhancement.

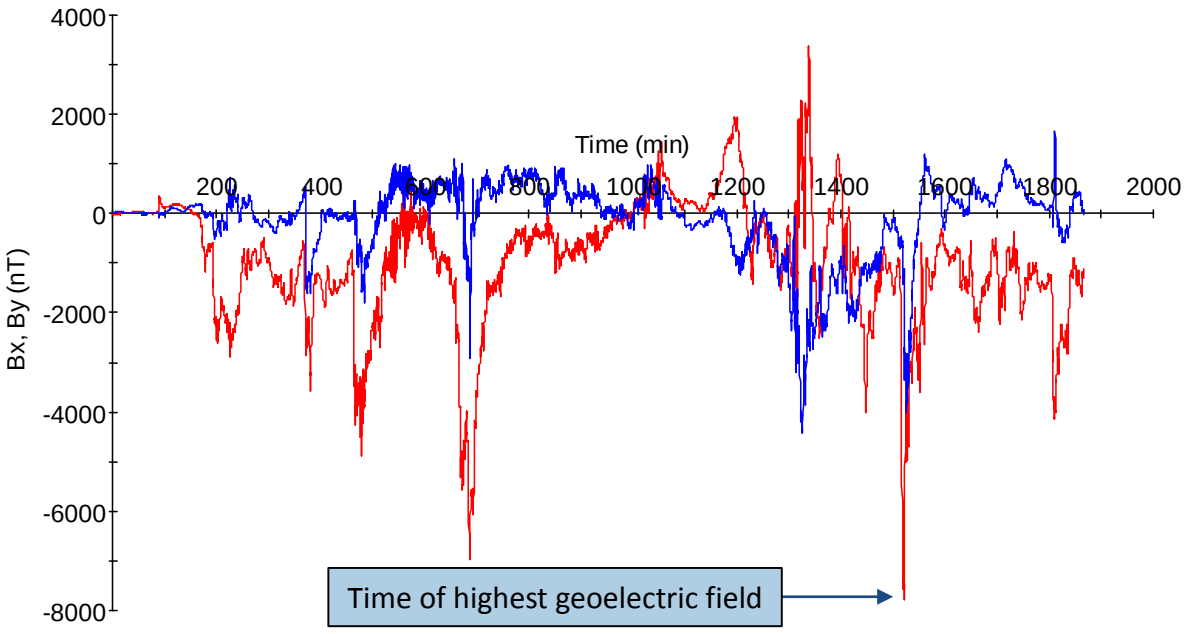


Figure I-12: Benchmark Geomagnetic Field. Red B_x (Northward), Blue B_y (Eastward)

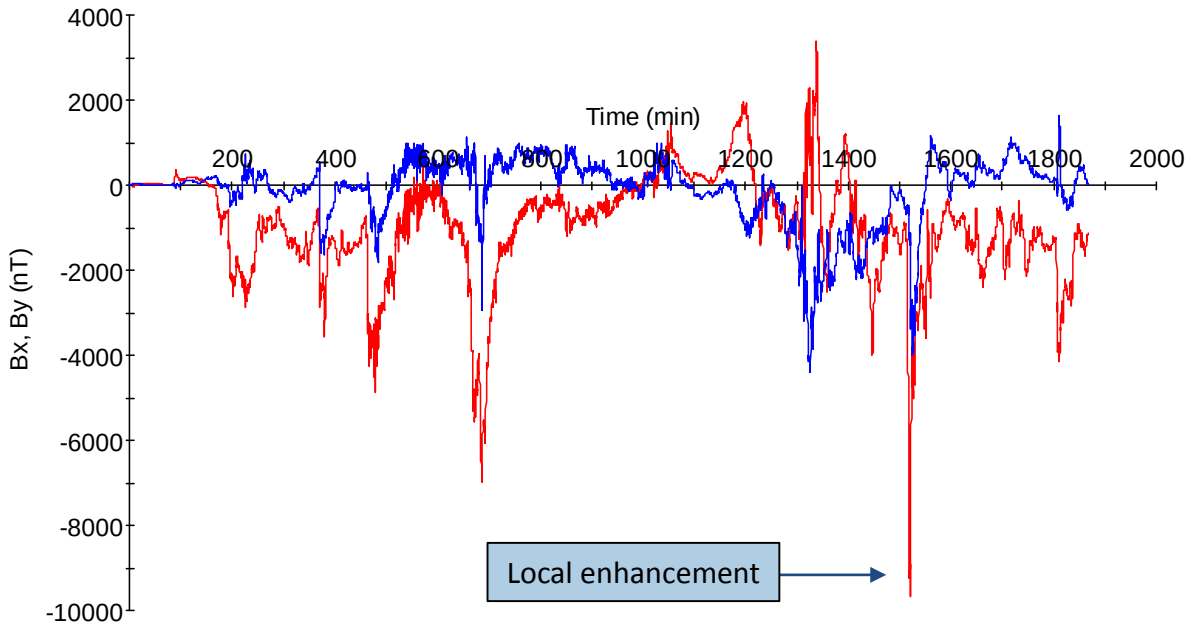


Figure I-13: Supplemental Geomagnetic Field Waveform. Red B_x (Northward), Blue B_y (Eastward)

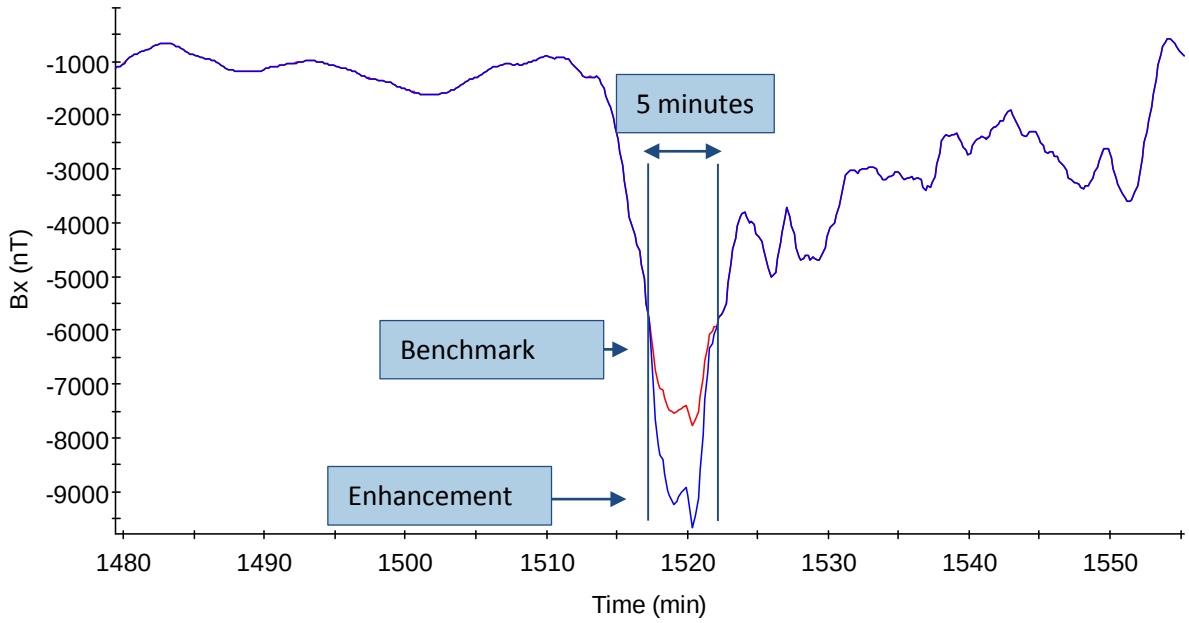


Figure I-14: Red Benchmark B_x and Blue Supplemental B_x (Northward) – Expanded View

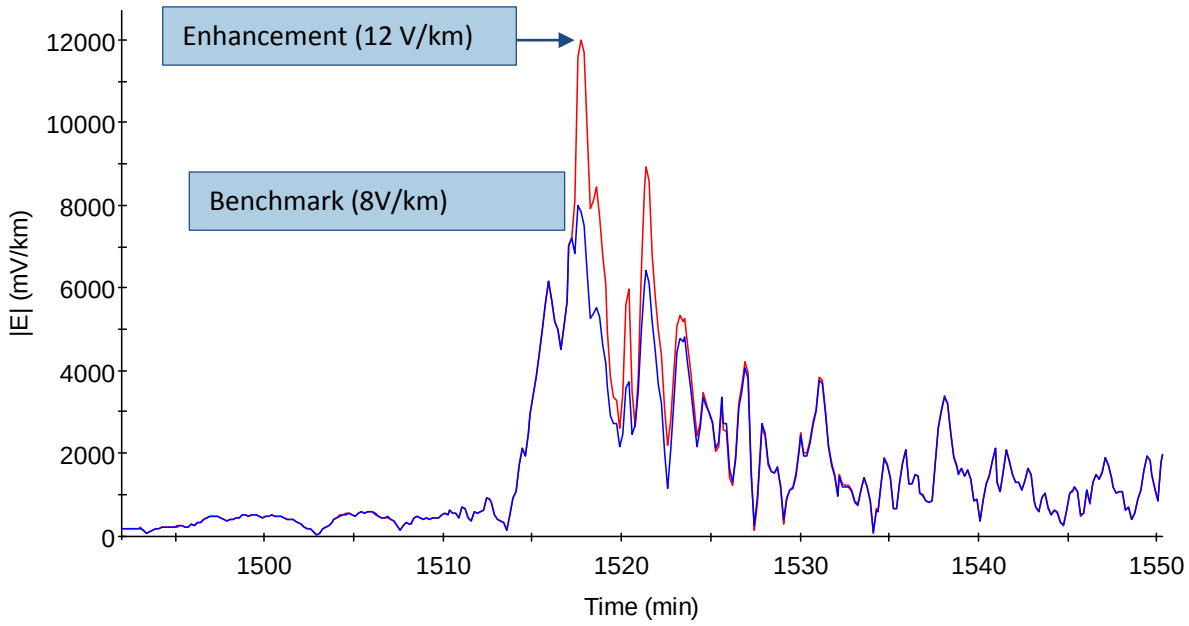


Figure I-15: Magnitude of the Geoelectric Field. Benchmark Blue and Supplemental Red – Expanded View

Transformer Thermal Assessment

The local enhancement of the supplemental GMD event waveform can have a material impact on the temperature rise (hot-spot heating or metallic parts) even though the duration of the local enhancement is approximately 5 minutes. Thermal assessments based on the supplemental GMD event can be performed using the same methods employed for benchmark thermal assessments.[9]

[9] See Transformer Thermal Impact Assessment white paper: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Appendix II – Scaling the Supplemental GMD Event

The intensity of a GMD event depends on geographical considerations such as geomagnetic latitude and local earth conductivity [2].[10] 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 supplemental GMD event differs from the benchmark GMD event in two ways:

- E_{peak} is 12 V/km instead of 8 V/km
- Beta factors for scaling the geoelectric field based on earth conductivity are different (see **Table II-2**)

More discussion, including example calculations, is contained in the Benchmark GMD Event Description white paper.

Scaling the Geomagnetic Field

The supplemental 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 supplemental geomagnetic field waveform 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]-[27], 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 $0.1 \leq \alpha \leq 1.0$.

[10] 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. 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.

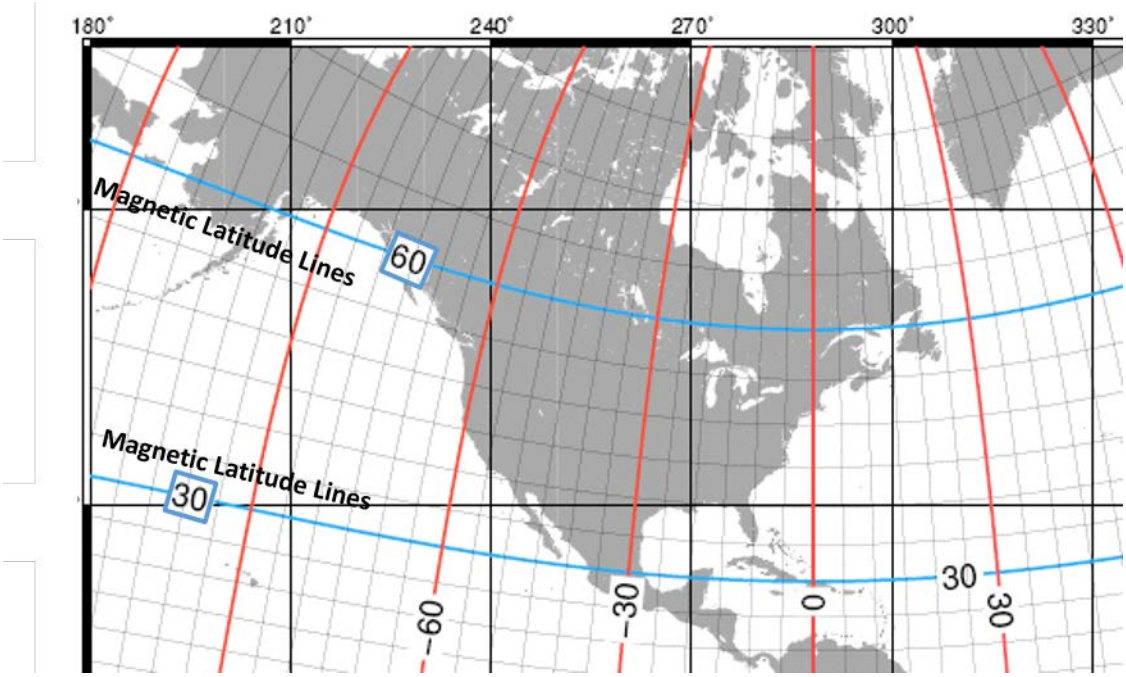


Figure II-1: Geomagnetic Latitude Lines in North America

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 supplemental 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 [11, 15]. The peak geoelectric field depends on the geomagnetic field waveform and the local earth conductivity. Ideally, the peak geoelectric field, E_{peak}, is obtained by calculating the geoelectric field from the scaled geomagnetic field waveform using the plane wave method and taking the maximum value of the resulting waveforms

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

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 waveforms,

$E_E(t)$, $E_N(t)|$ 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.

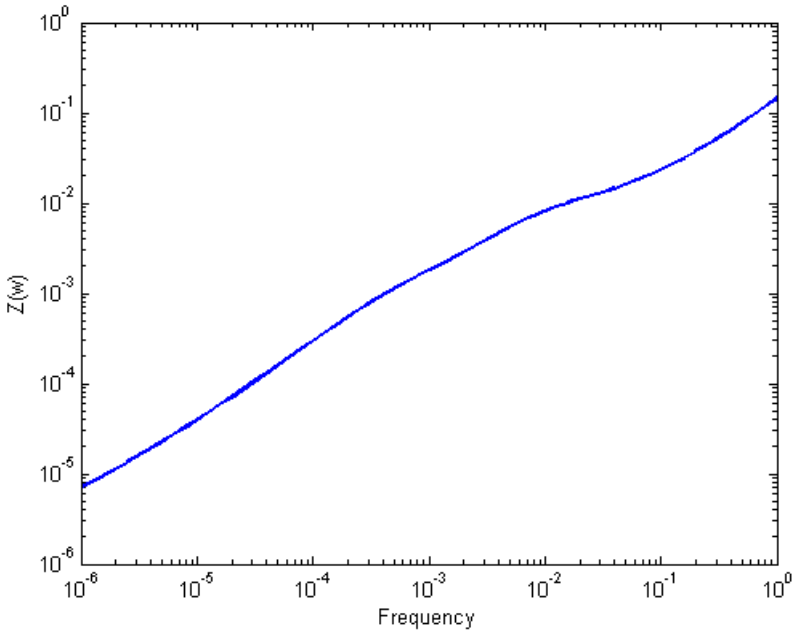


Figure II-2: Magnitude of the Earth Surface Impedance for the Reference Earth Model

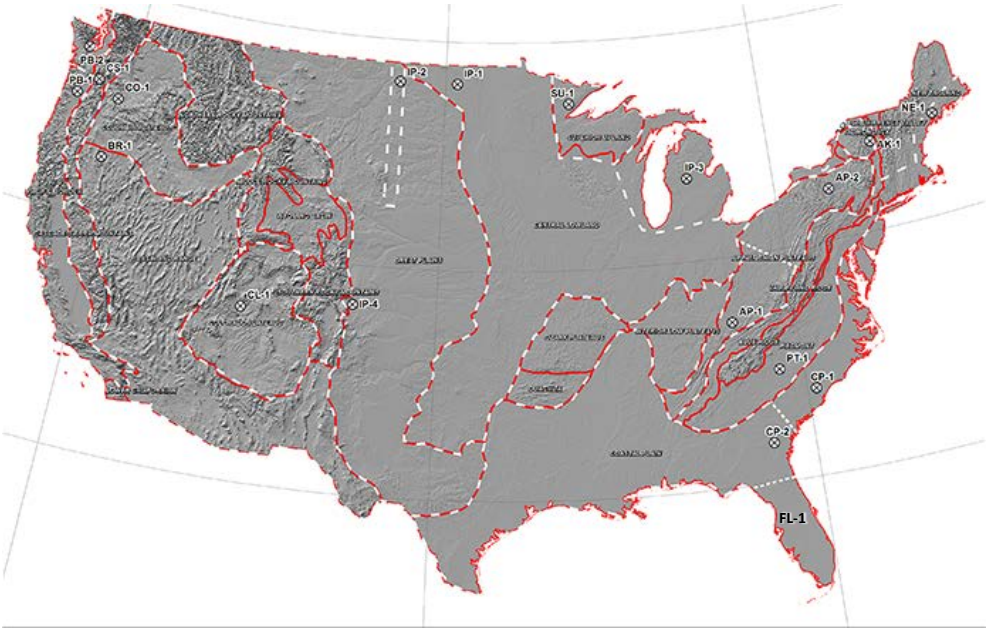
If a utility does not have the capability of calculating the waveform or time series for the geoelectric field, an earth conductivity scaling factor β_S can be obtained from **Table II-2**. Using α and β, the peak geoelectric field E_{peak} for a specific service territory shown in **Figure II-3** can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

$$E_{peak}\ 12 \times \alpha \times \beta_s \ (\text{V/km}) \quad \text{(II.3)}$$

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. These scaling factors are slightly lower than the ones in the benchmark because the supplemental benchmark waveform has a higher frequency content at the time of the local enhancement.
- 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_S 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 12 V/km. Both geoelectric field peak amplitudes are calculated using the supplemental 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. 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_s 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 Supplemental Geoelectric Field Scaling Factors	
Earth model	**Scaling Factor (β)**
AK1A	0.51
AK1B	0.51
AP1	0.30
AP2	0.78
BR1	0.22
CL1	0.73
CO1	0.25
CP1	0.77
CP2	0.86
FL1	0.73
CS1	0.37
IP1	0.90
IP2	0.25
IP3	0.90
IP4	0.35
NE1	0.77
PB1	0.55
PB2	0.39
PT1	1.19
SL1	0.49
SU1	0.90
BOU	0.24
FBK	0.56
PRU	0.22
BC	0.62
PRAIRIES	0.88
SHIELD	1.0
ATLANTIC	0.76

References

[1] *High-Impact, Low-Frequency Event Risk to the North American Bulk Power System*, A Jointly-Commissioned Summary Report of the North American Reliability Corporation and the U.S. Department of Energy's November 2009 Workshop.

[2] Application Guide: Computing Geomagnetically-Induced Current in the Bulk-Power System, NERC. NERC. http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf

[3] Kuan Zheng, Risto Pirjola, David Boteler, Lian-guang Liu, "Geoelectric Fields Due to Small-Scale and Large-Scale Source Currents", *IEEE Transactions on Power Delivery*, Vol. 28, No. 1, January 2013, pp. 442-449.

[4] Boteler, D. H. "Geomagnetically Induced Currents: Present Knowledge and Future Research", *IEEE Transactions on Power Delivery*, Vol. 9, No. 1, January 1994, pp. 50-58.

[5] Boteler, D. H. "Modeling Geomagnetically Induced Currents Produced by Realistic and Uniform Electric Fields", *IEEE Transactions on Power Delivery*, Vol. 13, No. 4, January 1998, pp. 1303-1308.

[6] J. L. Gilbert, W. A. Radasky, E. B. Savage, "A Technique for Calculating the Currents Induced by Geomagnetic Storms on Large High Voltage Power Grids", Electromagnetic Compatibility (EMC), 2012 IEEE International Symposium on.

[7] *How to Calculate Electric Fields to Determine Geomagnetically-Induced Currents.* EPRI, Palo Alto, CA: 2013. 3002002149.

[8] Pulkkinen, A., R. Pirjola, and A. Viljanen, Statistics of extreme geomagnetically induced current events, *Space Weather*, 6, S07001, doi:10.1029/2008SW000388, 2008.

[9] Boteler, D. H., Assessment of geomagnetic hazard to power systems in Canada, *Nat. Hazards*, 23, 101–120, 2001.

[10] Finnish Meteorological Institute's IMAGE magnetometer chain data available at: http://image.gsfc.nasa.gov/

[11] Boteler, D. H., and R. J. Pirjola, The complex-image method for calculating the magnetic and electric fields produced at the surface of the Earth by the auroral electrojet, *Geophys. J. Int.*, 132(1), 31—40, 1998

[12] Coles, Stuart (2001). An Introduction to Statistical Modelling of Extreme Values. Springer.

[13] Pulkkinen, A., A. Thomson, E. Clarke, and A. Mckay, April 2000 geomagnetic storm: ionospheric drivers of large geomagnetically induced currents, *Annales Geophysicae*, 21, 709-717, 2003.

[14] Pulkkinen, A., S. Lindahl, A. Viljanen, and R. Pirjola, Geomagnetic storm of 29–31 October 2003: Geomagnetically induced currents and their relation to problems in the Swedish high-voltage power transmission system, *Space Weather*, 3, S08C03, doi:10.1029/2004SW000123, 2005.

[15] Pulkkinen, A., E. Bernabeu, J. Eichner, C. Beggan and A. Thomson, Generation of 100-year geomagnetically induced current scenarios, *Space Weather*, Vol. 10, S04003, doi:10.1029/2011SW000750, 2012.

[16] Ngwira, C., A. Pulkkinen, F. Wilder, and G. Crowley, Extended study of extreme geoelectric field event scenarios for geomagnetically induced current applications, *Space Weather*, Vol. 11, 121–131, doi:10.1002/swe.20021, 2013.

[17] Thomson, A., S. Reay, and E. Dawson. Quantifying extreme behavior in geomagnetic activity, *Space Weather*, 9, S10001, doi:10.1029/2011SW000696, 2011.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Transformer Thermal Impact Assessment White Paper

~~Project 2013-03 (Geomagnetic Disturbance Mitigation)~~

TPL-007-~~1~~2~~–~~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.~~

Proposed TPL-007-2 includes requirements for entities to perform two types of GMD Vulnerability Assessments to evaluate the potential impacts of GMD events on the Bulk Electric System (BES):

- The benchmark GMD Vulnerability Assessment is based on the benchmark GMD event associated with TPL-007-1 which was approved by the Federal Energy Regulatory Commission (FERC) in Order No. 830 in September 2016. The benchmark GMD event is derived from spatially-averaged geoelectric field values to address potential wide-area effects that could be caused by a severe 1-in-100 year GMD event.[1]
- The supplemental GMD Vulnerability Assessment, based on the supplemental GMD event, is used by entities to evaluate localized peaks in geomagnetic field during a severe GMD event that "could

[1] See *Benchmark Geomagnetic Disturbance Event Description* white paper, May 12, 2016. Filed by NERC in RM15-11 on June 28, 2016.

potentially affect the reliable operation of the Bulk-Power System."[2] Localized enhancements of geomagnetic field can result in geoelectric field values above the spatially-averaged benchmark in a local area.

The standard requires transformer thermal impact assessments to be performed on BES power transformers with high side, wye-grounded windings with terminal voltage greater than 200 kV. 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-007-2 requires owners of such BES transformers to conduct thermal analyses to determine if the BES transformers will be able to withstand the thermal transient effects associated with the GMD events. BES Transformers must undergo a thermal impact assessment if the maximum effective geomagnetically-induced current (GIC) in the transformer is equal to or greater than:[3]

- 75 A per phase for the benchmark GMD event
- 85 A per phase for the supplemental GMD event

This white paper discusses methods that can be employed to conduct transformer thermal impact assessments, including example calculations. The first version of the white paper was developed by the Project 2013-03 GMD Standards Drafting Team (SDT) for TPL-007-1 and was endorsed by the Electric Reliability Organization (ERO) as implementation guidance in October 2016. The SDT has updated the white paper to include the supplemental GMD event that is added in TPL-007-2 to address directives in FERC Order No. 830.

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.

[2] See Order No. 830 P. 47. On September 22, 2016, FERC directed NERC to develop modifications to the benchmark GMD event, included in TPL-007-1, such that assessments would not be based solely on spatially averaged data. The characteristics of a GMD event for this assessment are in the Supplemental GMD Event Description white paper.

[3] See *Screening Criterion for Transformer Thermal Impact Assessment* for technical justification.

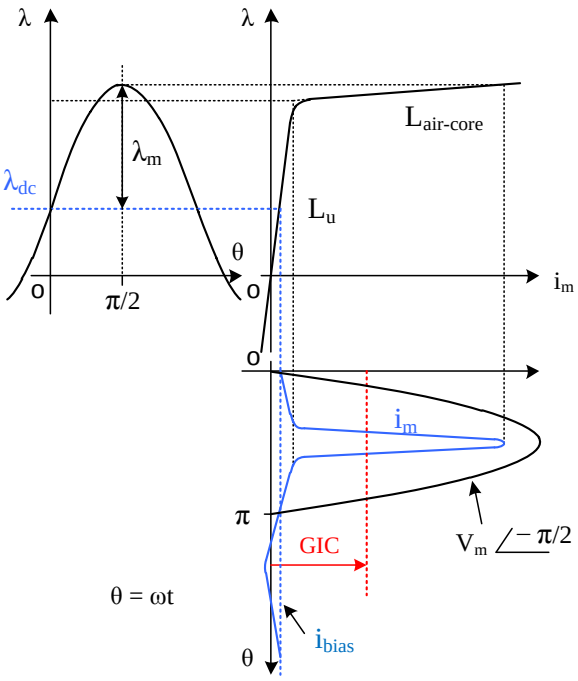


Figure 1: Mapping Magnetization Current to Flux through Core Excitation Characteristics

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.~~of GIC.

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]~~(IEEE Guide for Loading Mineral-oil-immersed Transformers and Step-voltage Regulators) for hot spot heating during short-

term emergency operation. [1]. 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 "waveshapewaveform" 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 2the appropriate tables from the "Screening Criterion for Transformer Thermal Impact Assessment" white paper [7]. This3].[4] Each table, shown as Table 1 below, provides the peak metallic hot spot temperatures that can be reached for the given GMD event using conservative thermal models. To use Table 1each table, one must select the bulk oil temperature and the threshold for metallic hot spot heating, for instance, from reference [1] after

[4] Table 1 in the *Screening Criterion for Transformer Thermal Impact Assessment* white paper provides upper bound temperatures for the benchmark GMD event. Table 2 in the *Screening Criterion for Transformer Thermal Impact Assessment* white paper provides upper bound temperatures for the supplemental GMD event.

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.[5]

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

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

Effective GIC (A/phase)	Metallic hot spot Temperature (°C)	Effective GIC(A/phase)	Metallic hot spot Temperature (°C)
0	80	120	188
10	107	130	191
20	124	140	194
30	137	150	198
40	147	160	203
50	156	170	209
60	161	180	214
70	162	190	229
75	165	200	237
80	169	220	248
85	172	230	253

[5] Effective GIC in the table is the peak GIC(t) for the GMD event being assessed. Peak GIC(t) is not steady-state GIC.

90	177	250	276
100	181	275	298
110	185	300	316

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) or International Council on Large Electric Systems (CIGRE) may also provide technically justified methods for performing thermal assessments.[6] All thermal assessment methods should be demonstrably equivalent to assessments that use the ~~benchmark GMD event.~~GMD events associated with TPL-007-2.

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~~waveform 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~~.~~ [5]. While GIC capability curves are relatively simple to use, an amount of engineering judgment is necessary to ascertain which portion of a GIC ~~waveshape~~waveform is equivalent to, for example, a 2 minute pulse. Also, manufacturers generally maintain that in the absence of transformer standards defining thermal duty due to GIC, such capability curves must be developed for every transformer design and vintage.

[6] For example, C57.163-2015 – IEEE Guide for Establishing Power Transformer Capability while under Geomagnetic Disturbances. [4]

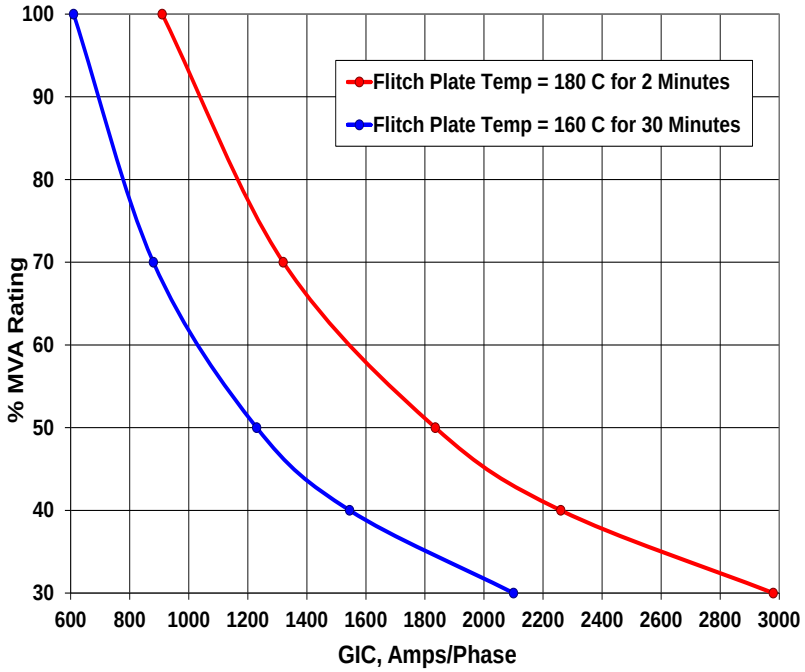


Figure 2: Sample GIC Manufacturer Capability Curve of a Large Single-Phase Transformer Design using the Flitch Plate Temperature Criteria [~~3~~35]

2. Thermal response simulation.[7] ~~.~~ The input to this type of simulation is the time series or ~~waveshape~~waveform 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~~46] 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~~46]) when specific data are not available. Hot spot temperature thresholds shown in **Figure 3** are consistent with IEEE Std C57.91-2011 emergency loading hot spot limits. Emergency loading time limit is usually 30 minutes.

[7] Technical details of this methodology can be found in [~~4~~46].

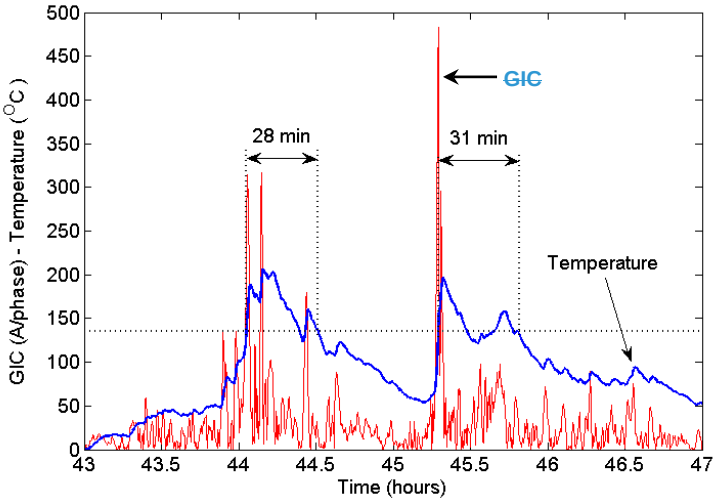


Figure 3: Sample Tie Plate Temperature Calculation
Blue trace is incremental temperature and red trace is the magnitude of the GIC/phase [~~4~~] 6]

It is important to reiterate that the characteristics of the time sequence or "~~waveshape~~waveform" 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~~Waveform 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~~/~~ per 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]~~(from [7] and/or [8]) after the appropriate geomagnetic latitude scaling factor α is applied.[8] ~~.~~ 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 appropriate conductivity scaling factor ~~ββ.~~[9] ~~.~~ 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~~7]. The resulting geoelectric field time series is shown in **Figure 4**. Therefore:

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

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

[8] 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.

[9] 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.

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

It should be emphasized that even for the same reference event, the GIC(t) ~~waveshape~~waveform 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~~waveform to test all transformers is incorrect.

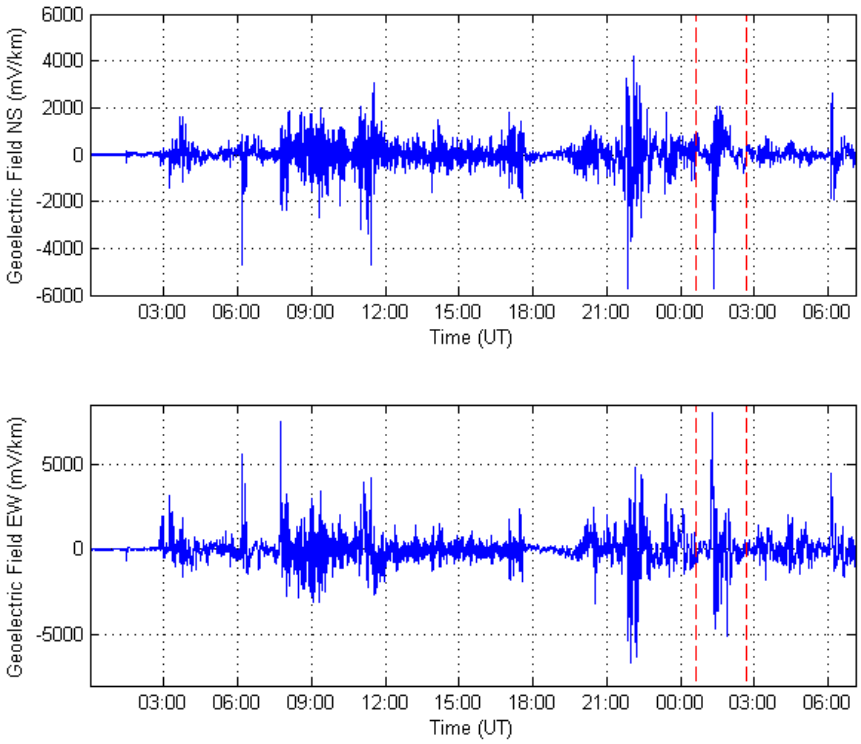


Figure 4: Calculated Geoelectric Field $E_N(t)$ and $E_E(t)$ Assuming $\alpha=1$ and $\beta=1$ (Reference Earth Model).
Zoom area for subsequent graphs is highlighted.
Dashed lines approximately show the close-up area for subsequent Figures.

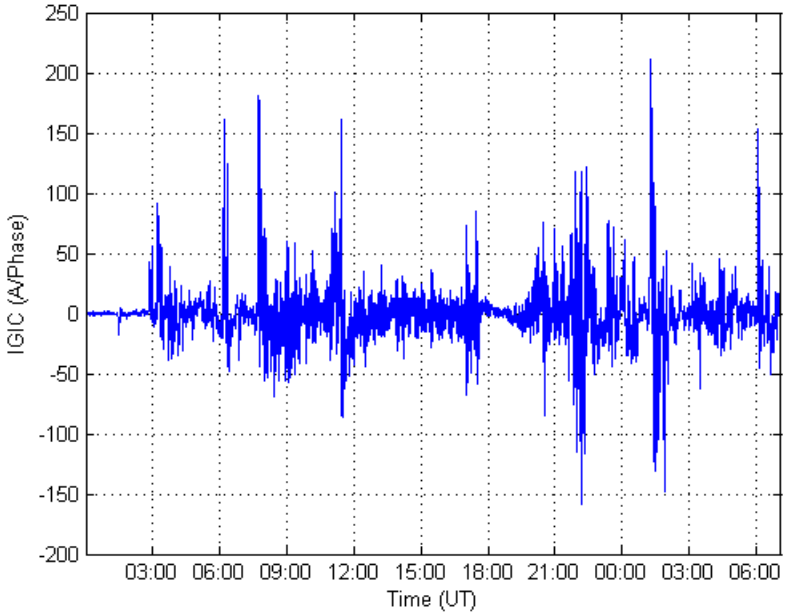


Figure 5: Calculated GIC(t) Assuming $\alpha=1$ and $\beta=1$
{Reference Earth Model}

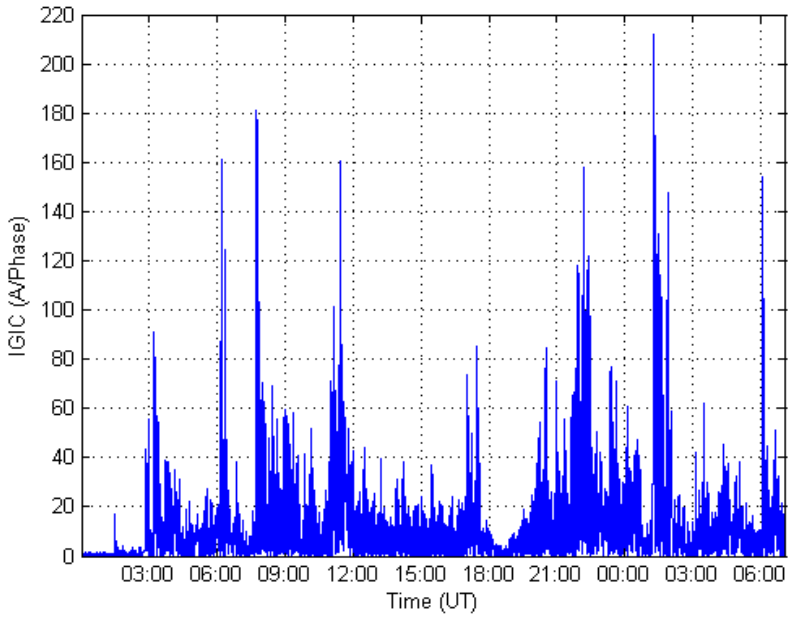


Figure 6: Calculated Magnitude of GIC(t) Assuming $\alpha=1$ and $\beta=1$
{Reference Earth Model}

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~~9] 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.[10]

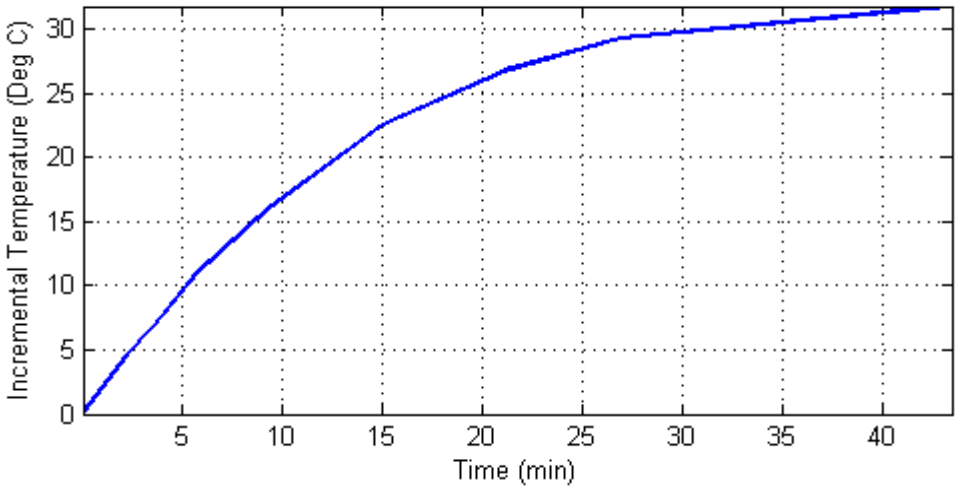


Figure 7: Thermal Step Response to a 16.67 Amperes per Phase dc Step

Metallic hot spot heating~~.~~

[10] 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.

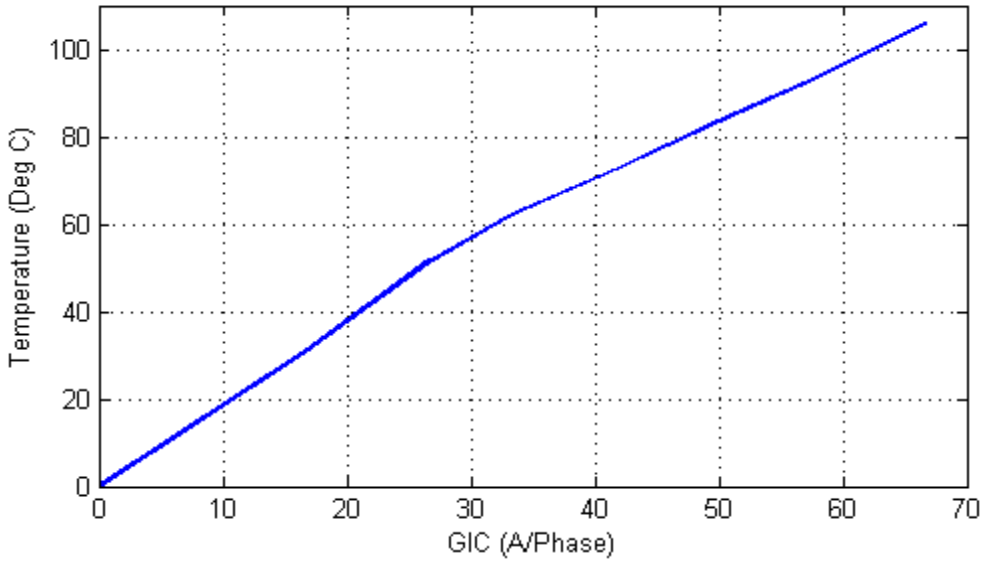


Figure 8: Asymptotic Thermal Step Response

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.

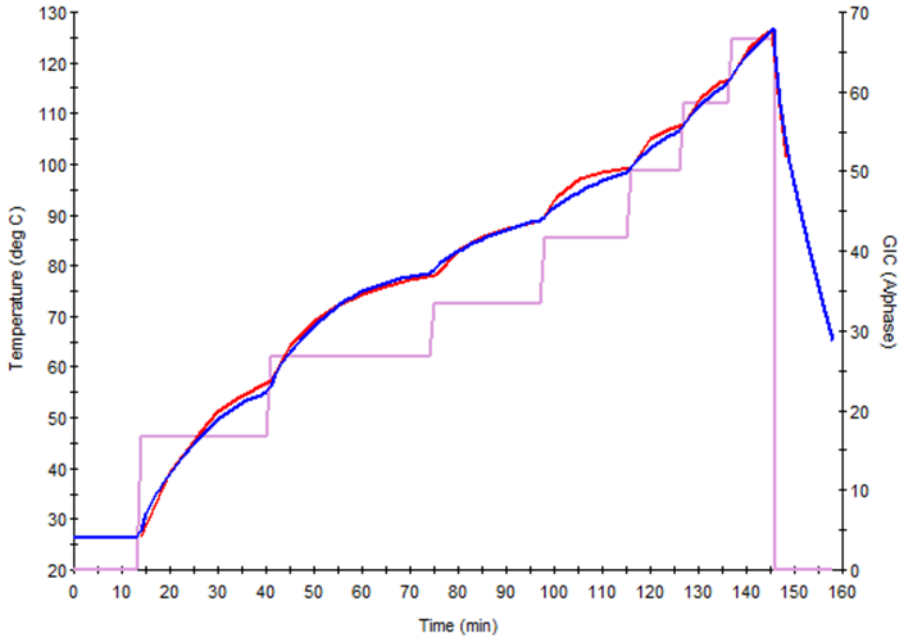


Figure 9: Comparison of measured temperatures (red ~~trace~~) and simulation results (blue ~~trace).~~).

Injected current is represented by ~~the~~ magenta ~~trace~~.

To obtain the thermal response of the transformer to a GIC ~~waveshape~~waveform 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~~waveform 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~~waveform. 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 metallic hot spot temperature time series θ(t). **Figure 11** illustrates a close-up view of the peak transformer temperatures calculated in this example.

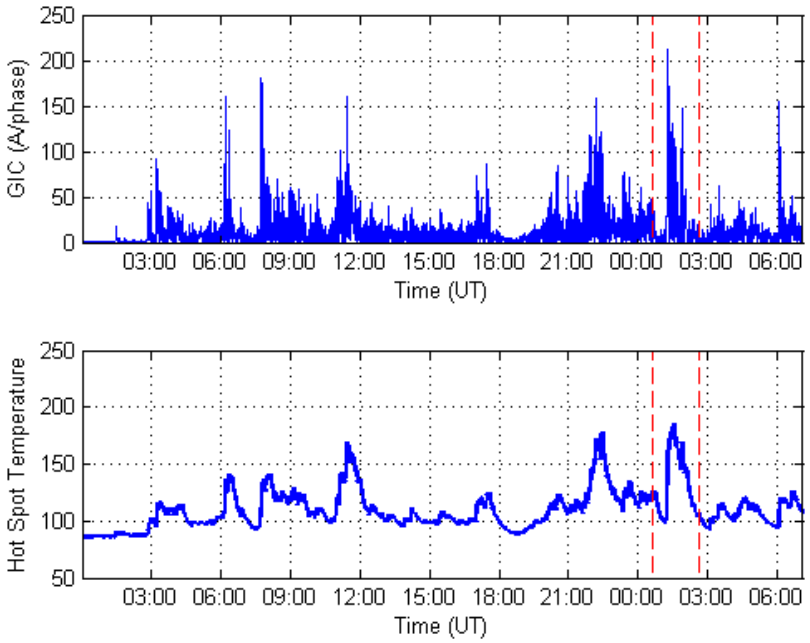


Figure 10: Magnitude of GIC(t) and Metallic Hot Spot Temperature θ(t) Assuming Full Load Oil Temperature of 85.3°C (40°C ambient). Dashed lines approximately show the close-up area for subsequent Figures.

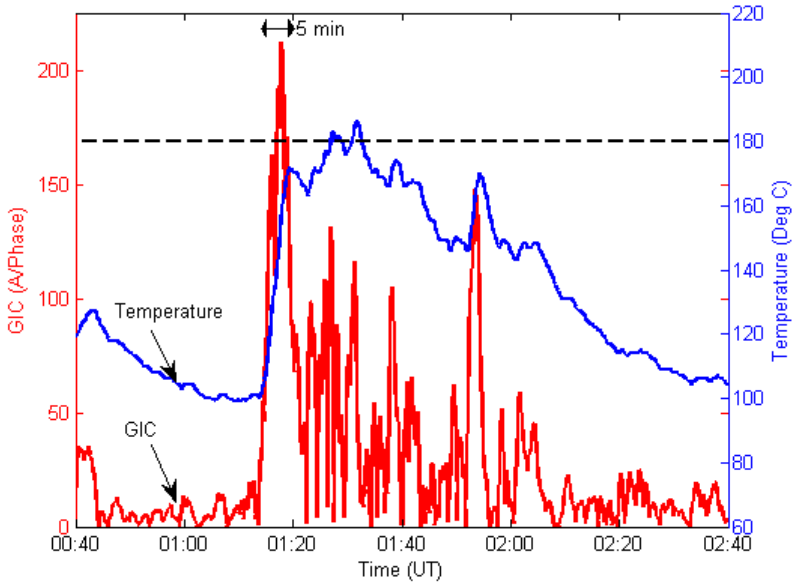


Figure 11: Close-up of Metallic Hot Spot Temperature Assuming a Full Load
(Blue trace is θ(t). Red trace is GIC(t))

In this example, the IEEE Std C57.91-2011 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.

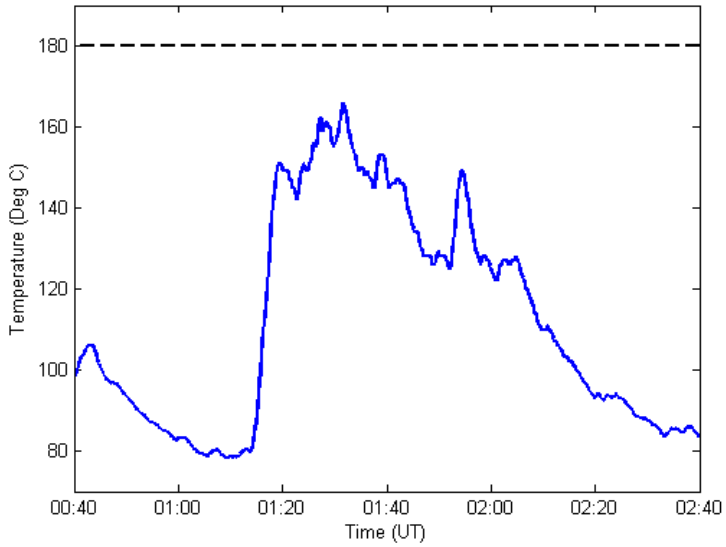


Figure 12: Close-up of Metallic Hot Spot Temperature Assuming a 75% Load
(Oil temperature of 64.5°C)

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~~).~~ 2011).

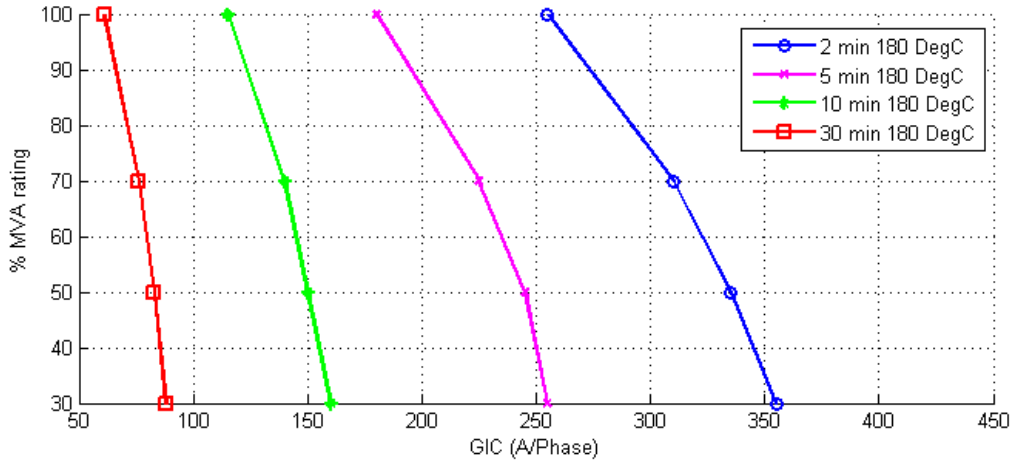


Figure 13: Capability Curve of a Transformer Based on the Thermal Response Shown in Figures 8 and 9.

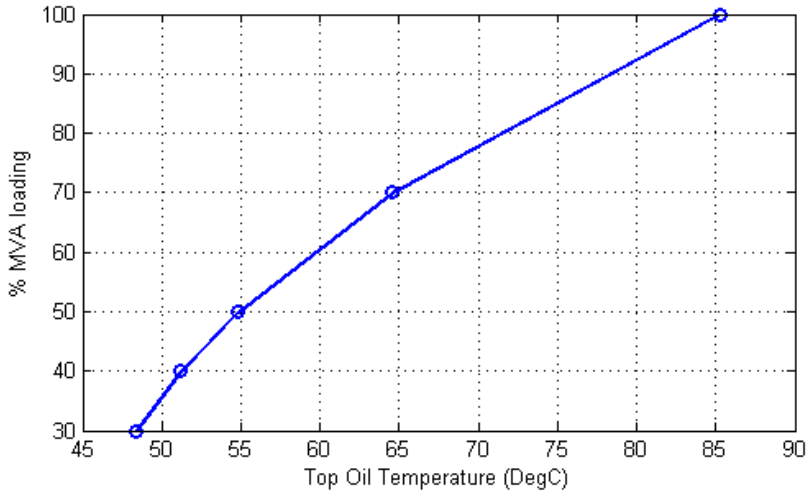


Figure 14: Simplified Loading Curve Assuming 40°C Ambient Temperature.

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~~waveform 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.

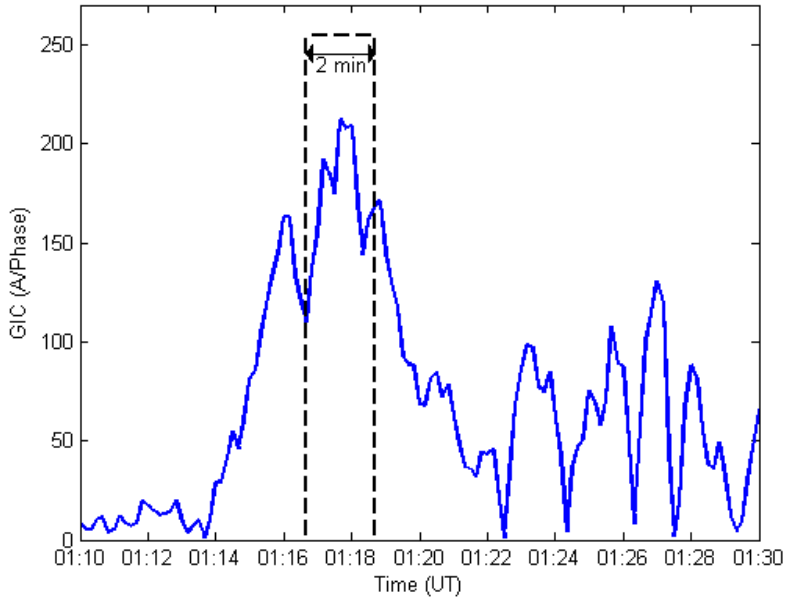


Figure 15: Close-up of GIC(t) and a 2 minute 255 A/phase GIC pulse at full load

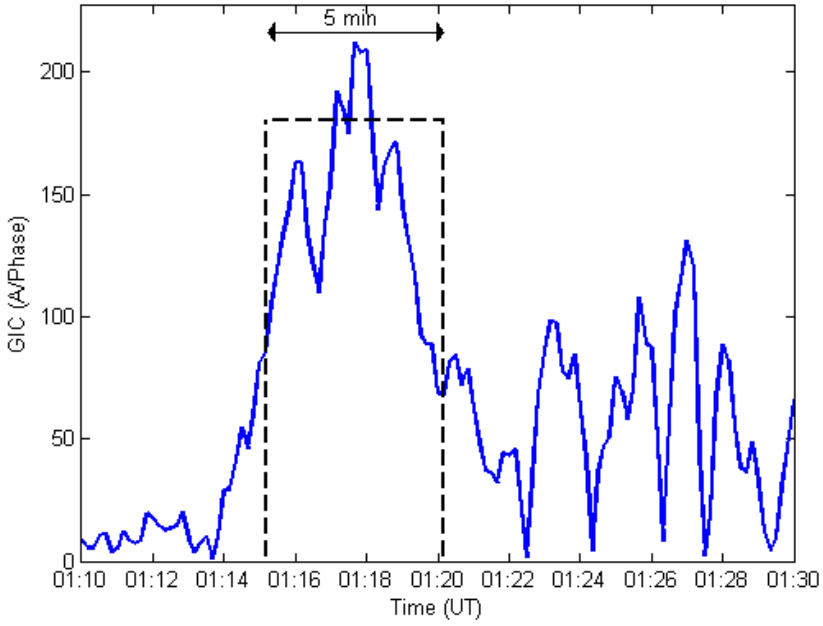


Figure 16: Close-up of GIC(t) and a Five Minute 180 A/phase GIC Pulse at Full Load

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 metallic 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.

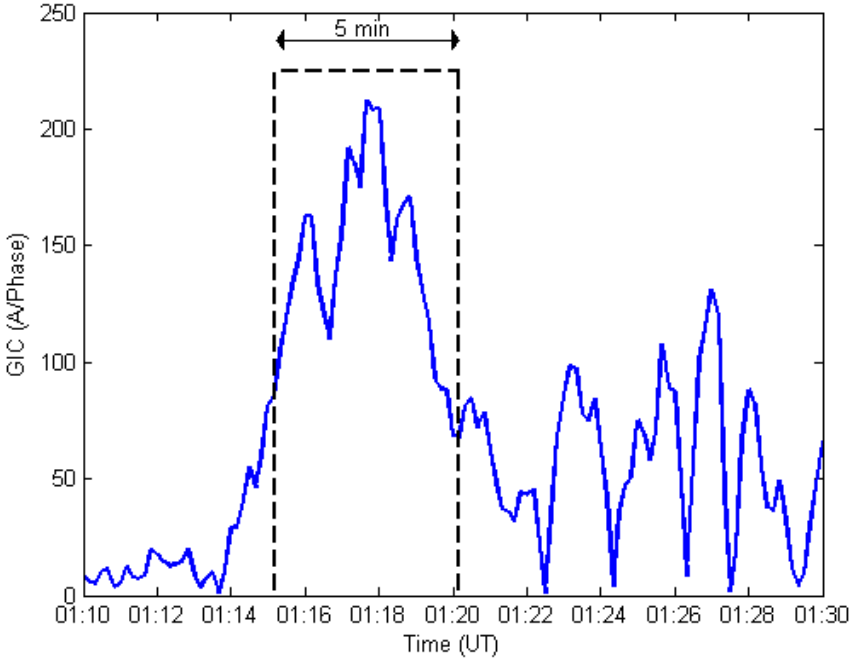


Figure 17: Close-up of GIC(t) and a 5 Minute 225 A/phase GIC Pulse Assuming 75% Load

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] "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/TPL0071RI.aspx

[4] "IEEE Guide for Establishing Power Transformer Capability while under Geomagnetic Disturbances." IEEE Std C57.163-2015

~~[3]~~[5] 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]~~[6] 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]~~[7] 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/TPL0071RI.aspx

[8] Supplemental 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]~~[9] 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]~~[1] ~~"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~~

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

The standard drafting team (PRC_025) is posting Draft 1 of PRC-025-2, Generator Relay Loadability for a 45-day formal comment period and initial ballot in the last ten days of the comment period.

Completed Actions	Date
The Standards Committee (SC) authorized the SAR for posting	September 14, 2016
Draft 1 of the Standards Authorization Request (SAR) was posted for a 30-day formal comment period	September 16, 2016 through October 18, 2016
Draft 2 of the SAR was posted for a 15-day informal comment period	March 20, 2017 through April 3, 2017
The SC accepted the SAR and appointed the SAR drafting team as the standard drafting team (SDT)	April 19, 2017

Anticipated Actions	Date
45-day formal comment period with initial ballot	July 2017
45-day formal comment period with additional ballot	September 2017
10-day final ballot	January 2018
Board adoption	February 2018

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None.

A. Introduction

1. **Title:** **Generator Relay Loadability**

2. **Number:** **PRC-025-~~1~~2**

3. **Purpose:** To set load-responsive protective relays associated with generation Facilities at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Generator Owner that applies load-responsive protective relays at the terminals of the Elements listed in 3.2, Facilities.

   4.1.2. Transmission Owner that applies load-responsive protective relays at the terminals of the Elements listed in 3.2, Facilities.

   4.1.3. Distribution Provider that applies load-responsive protective relays at the terminals of the Elements listed in 3.2, Facilities.

   4.2. Facilities: The following Elements associated with Bulk Electric System (BES) generating units and generating plants, including those generating units and generating plants identified as Blackstart Resources in the Transmission Operator's system restoration plan:

   4.2.1. Generating unit(s).

   4.2.2. Generator step-up (i.e., GSU) transformer(s).

   4.2.3. Unit auxiliary transformer(s) (UAT) that supply overall auxiliary power necessary to keep generating unit(s) online.[1]

   4.2.4. Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

   4.2.5. Elements utilized in the aggregation of dispersed power producing resources.

5. **Effective Date:** See Implementation Plan

[1] These transformers are variably referred to as station power, unit auxiliary transformer(s) (UAT), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Loss of these transformers will result in removing the generator from service. Refer to the PRC-025-~~1~~2 Guidelines and Technical Basis for more detailed information concerning unit auxiliary transformers.

~~5.~~ **Background:**

6. After analysis of many of the major disturbances in the last 25 years on the North American interconnected power system, generators have been found to have tripped for conditions that did not apparently pose a direct risk to those generators and associated equipment within the time period where the tripping occurred. This tripping has often been determined to have expanded the scope and/or extended the duration of that disturbance. This was noted to be a serious issue in the August 2003 "blackout" in the northeastern North American continent.[2]

During the recoverable phase of a disturbance, the disturbance may exhibit a "voltage disturbance" behavior pattern, where system voltage may be widely depressed and may fluctuate. In order to support the system during this transient phase of a disturbance, this standard establishes criteria for setting load-responsive protective relays such that individual generators may provide Reactive Power within their dynamic capability during transient time periods to help the system recover from the voltage disturbance. The premature or unnecessary tripping of generators resulting in the removal of dynamic Reactive Power exacerbates the severity of the voltage disturbance, and as a result changes the character of the system disturbance. In addition, the loss of Real Power could initiate or exacerbate a frequency disturbance.

7. Standard Only Definition: None.

~~**7.1. Effective Date:** See Implementation Plan~~

B. Requirements and Measures

R1. Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-~~1~~2 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection. *[Violation Risk Factor: High] [Time Horizon: Long-Term Planning]*

M1. For each load-responsive protective relay, each Generator Owner, Transmission Owner, and Distribution Provider shall have evidence (e.g., summaries of calculations, spreadsheets, simulation reports, or setting sheets) that settings were applied in accordance with PRC-025-~~1~~2 – Attachment 1: Relay Settings.

C. Compliance

[2] Interim Report: Causes of the August 14th Blackout in the United States and Canada, U.S.-Canada Power System Outage Task Force, November 2003 (http://www.nerc.com/docs/docs/blackout/814BlackoutReport.pdf)

8. Compliance Monitoring Process

8.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

8.2. Evidence Retention

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

The Generator Owner, Transmission Owner, and Distribution Provider shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner, Transmission Owner, and Distribution Provider shall retain evidence of Requirement R1 and Measure M1 for the most recent three calendar years.
- If a Generator Owner, Transmission Owner, or Distribution Provider 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.

8.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

8.4. Additional Compliance Information

None

~~Table of Compliance Elements~~

:

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-Term Planning	High	N/A	N/A	N/A	The Generator Owner, Transmission Owner, and Distribution Provider did not apply settings in accordance with *PRC-025-~~1~~2 – Attachment 1: Relay Settings*, on an applied load-responsive protective relay.

D. Regional Variances

None.

~~E. Interpretations~~

~~F.~~E. Associated Documents

NERC System Protection and Control Subcommittee, ~~July 2010, "~~"Considerations for Power Plant and Transmission System Protection Coordination~~."~~," technical reference document, Revision 2. (Date of Publication: July 2015)

IEEE C37.102-2006, "IEEE Guide for AC Generator Protection." (Date of Publication: 2006)

IEEE C37.17-2012, “IEEE Standard for Trip Systems for Low-Voltage (1000 V and below) AC and General Purpose (1500 V and below) DC Power Circuit Breakers.” (Date of Publication: September 18, 2012)

IEEE C37.2-2008, “IEEE Standard for Electrical Power System Device Function Numbers, Acronyms, and Contact Designations.” (Date of Publication: October 3, 2008)

Version History

Version	Date	Action	Change Tracking
1	August 15, 2013	Adopted by NERC Board of Trustees	New
1	July 17, 2014	FERC order issued approving PRC-025-1	

~~PRC-025-1~~2	April 19, 2017	SAR accepted by Standards Committee	Revision
2		Adopted by NERC Board of Trustees	
2		FERC order issued approving PRC-025-2	

PRC-025-2 – Attachment 1: Relay Settings

Introduction

This standard does not require the Generator Owner, Transmission Owner, or Distribution Provider to use any of the protective functions listed in Table 1. Each Generator Owner, Transmission Owner, and Distribution Provider that applies load-responsive protective relays on their respective Elements listed in 3.2, Facilities, shall use one of the following Options in Table 1, Relay Loadability Evaluation Criteria ("Table 1"), to set each load-responsive protective relay element according to its application and relay type. The bus voltage is based on the criteria for the various applications listed in Table 1.

Generators

Synchronous generator relay ~~pickup~~ setting criteria values are derived from the unit's maximum gross Real Power capability, in megawatts (MW), as reported to the Transmission Planner, and the unit's Reactive Power capability, in megavoltampere-reactive (Mvar), is determined by calculating the MW value based on the unit's nameplate megavoltampere (MVA) rating at rated power factor. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard as a minimum requirement. The Generator Owner may base settings on a capability that is higher than what is reported to the Transmission Planner.

Asynchronous generator relay ~~pickup~~ setting criteria values (including inverter-based installations) are derived from the site's aggregate maximum complex power capability, in MVA, as reported to the Transmission Planner, including the Mvar output of any static or dynamic reactive power devices. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard as a minimum requirement. The Generator Owner may base settings on a capability that is higher than what is reported to the Transmission Planner.

For ~~the application case~~applications where synchronous and asynchronous generator types are combined on a generator step-up transformer or on Elements that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads~~.),)~~, the ~~pickup~~ setting criteria shall be determined by vector summing the ~~pickup~~ setting criteria of each generator type, and using the bus voltage for the given synchronous generator application and relay type.

Transformers

Calculations using the GSU transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with ~~deenergized~~de-energized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU transformer turns ratio shall be used.

Applications that use more complex topology, such as generators connected to a multiple winding transformer, are not directly addressed by the criteria in Table 1. These topologies can result in complex power flows, and may require simulation to avoid overly conservative

assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

Multiple Lines

Applications that use more complex topology, such as multiple lines that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads) are not directly addressed by the criteria in Table 1. These topologies can result in complex power flows, and it may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

Exclusions

The following protection systems are excluded from the requirements of this standard:

1. Any relay elements that are in service only during start up.
2. Load-responsive protective relay elements that are armed only when the generator is disconnected from the system, (e.g., non-directional overcurrent elements used in conjunction with inadvertent energization schemes, and open breaker flashover schemes).
3. Phase fault detector relay elements employed to supervise other load-responsive phase distance elements (e.g., in order to prevent false operation in the event of a loss of potential) provided the distance element is set in accordance with the criteria outlined in the standard.
4. Protective relay elements that are only enabled when other protection elements fail (e.g., overcurrent elements that are only enabled during loss of potential conditions).
5. Protective relay elements used only for ~~Special Protection Systems~~Remedial Action Schemes that are subject to one or more requirements in a NERC or Regional Reliability Standard.
6. Protection systems that detect generator overloads that are designed to coordinate with the generator short time capability by utilizing an extremely inverse characteristic set to operate no faster than 7 seconds at 218% of ~~fullload~~full load current (e.g., rated armature current), and prevent operation below 115% of full-load current.[3]
7. Protection systems that detect ~~transformer~~ overloads and are designed only to respond in time periods which allow an operator 15 minutes or greater to respond to overload conditions.

Table 1

Table 1 ~~beginning on the next page~~below is structured and formatted to aid the reader with identifying an option for a given load-responsive protective relay.

The first column identifies the application (e.g., synchronous or asynchronous generators, generator step-up transformers, unit auxiliary transformers, Elements that connect the GSU

[3] IEEE C37.102-2006, "Guide for AC Generator Protection," Section 4.1.1.2.

transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~. Elements may also supply generating plant loads).~~). Dark blue horizontal bars, excluding the header which repeats at the top of each page, demarcate the various applications.

The second column identifies the load-responsive distance or overcurrent protective relay by IEEE device numbers (e.g., 21, 50, 51, 51V-C, 51V-R, or 67) according to the ~~applied~~ application in the first column. This also includes manufacture protective device trip unit designations for long-time delay, short-time delay, and instantaneous (e.g., L, S, and I). A light blue horizontal bar between the relay types is the demarcation between relay types for a given application. These light blue bars will contain no text~~.~~, except when the same application continues on the next page of the table with a different relay type.

The third column uses numeric and alphabetic options (i.e., index numbering) to identify the available options for setting load-responsive protective relays according to the application and applied relay type. Another, shorter, light blue bar contains the word “OR,” and reveals to the reader that the relay for that application has one or more options (i.e., “ways”) to determine the bus voltage and ~~pickup~~ setting criteria in the fourth and fifth column, respectively. The bus voltage column and ~~pickup~~ setting criteria columns provide the criteria for determining an appropriate setting.

The table is further formatted by shading groups of relays associated with asynchronous generator applications. Synchronous generator applications and the unit auxiliary transformer applications are not shaded. Also, intentional buffers were added to the table such that similar options, as possible, would be paired together on a per page basis. Note that some applications may have an additional pairing that might occur on adjacent pages.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**~~Pickup~~ Setting Criteria**
Synchronous generating unit(s), ~~or~~including Elements utilized in the aggregation of dispersed power producing resources	Phase distance relay (e.g., 21) – directional toward the Transmission system	1a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		1b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		1c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[4] Calculations using the generator step-up (GSU) transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with deenergized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU turns ratio shall be used.

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[4]	~~Pickup~~ Setting Criteria
Synchronous generating unit(s), ~~or~~including Elements utilized in the aggregation of dispersed power producing resources	Phase ~~time~~ overcurrent relay (e.g., 50, 51~~),~~ or ~~(~~51V-R~~)~~ – voltage-restrained)	2a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		2b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		2c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner or, and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation
	~~The same application continues with a different relay type below~~			
	Phase time overcurrent relay (e.g., 51V-C) – voltage controlled (Enabled to operate as a function of voltage)	3	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage

A different application starts on the next page

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[4]	~~Pickup~~ Setting Criteria
Asynchronous generating unit(s) (including inverter-based installations), ~~or~~including Elements utilized in the aggregation of dispersed power producing resources	Phase distance relay (e.g., 21) – directional toward the Transmission system	4	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase ~~time~~ overcurrent relay (e.g., 50, 51~~),~~ or ~~(~~51V-R~~)~~ – voltage-restrained~~)~~	~~5~~5a	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
		OR		
		5b	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall not infringe upon the resource capability (including the Mvar output of the resource and any static or dynamic reactive power devices) with worst case documented tolerances applied between the maximum resource capability and the overcurrent element (see Figure A).
	Phase time overcurrent relay (e.g., 51V-C) – voltage controlled (Enabled to operate as a function of voltage)	6	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage

A different application starts on the next page

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**~~Pickup~~ Setting Criteria**
Generator step-up transformer(s) connected to synchronous generators	Phase distance relay (e.g., 21) – directional toward the Transmission system – installed on generator-side of the GSU transformer ~~If the relay is installed on the high-side of the GSU transformer use Option 14~~ [5]	7a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		7b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		7c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[5] If the relay is installed on the high-side of the GSU transformer use Option 14.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**~~Pickup~~ Setting Criteria**
Generator step-up transformer(s) connected to synchronous generators	Phase ~~time~~ overcurrent relay (e.g., 50 or 51) – installed on generator-side of the GSU transformer ~~If the relay is installed on the high-side of the GSU transformer use Option 15~~ [6]	8a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		8b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		8c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[6] If the relay is installed on the high-side of the GSU transformer use Option 15.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**~~Pickup~~ Setting Criteria**
Generator step-up transformer(s) connected to synchronous generators	Phase directional ~~time~~ overcurrent relay (e.g., 67) – directional toward the Transmission system – installed on generator-side of the GSU transformer ~~If the relay is installed on the high-side of the GSU transformer use Option 16~~ [7]	9a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		9b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		9c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
A different application starts on the next page				

[7] If the relay is installed on the high-side of the GSU transformer use Option 16.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**~~Pickup~~ Setting Criteria**
Generator step-up transformer(s) connected to asynchronous generators only (including inverter-based installations)	Phase distance relay (e.g., 21) – directional toward the Transmission system – installed on generator-side of the GSU transformer ~~If the relay is installed on the high-side of the GSU transformer use Option 17~~[8]	10	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase ~~time~~ overcurrent relay (e.g., 50 or 51) – installed on generator-side of the GSU transformer ~~If the relay is installed on the high-side of the GSU transformer use Option 18~~[9]	11	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer for overcurrent relays installed on the low-side	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	~~The same application continues on the next page with a different relay type~~			

[8] If the relay is installed on the high-side of the GSU transformer use Option 17.
[9] If the relay is installed on the high-side of the GSU transformer use Option 18.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**~~Pickup~~ Setting Criteria**
	Phase directional ~~time~~ overcurrent relay (e.g., 67) – directional toward the Transmission system – installed on generator-side of the GSU transformer ~~If the relay is installed on the high-side of the GSU transformer use Option 19~~[10]	12	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
A different application starts ~~below~~on the next page				
Unit auxiliary transformer(s) (UAT)	Phase ~~time~~ overcurrent relay (e.g., 50 or 51) applied at the high-side terminals of the UAT, for which operation of the relay will cause the associated generator to trip.	13a	1.0 per unit of the winding nominal voltage of the unit auxiliary transformer	The overcurrent element shall be set greater than 150% of the calculated current derived from the unit auxiliary transformer maximum nameplate MVA rating
		OR		
		13b	Unit auxiliary transformer bus voltage corresponding to the measured current	The overcurrent element shall be set greater than 150% of the unit auxiliary transformer measured current at the generator maximum gross MW capability reported to the Transmission Planner
~~A different application starts on the next page~~				

[10] If the relay is installed on the high-side of the GSU transformer use Option 19.

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[4]	~~Pickup~~ Setting Criteria
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. (Elements may also supply generating plant loads.) – connected to synchronous generators	Phase distance relay (e.g., 21) – directional toward the Transmission system —installed on the high-side of the GSU transformer ~~If the relay is installed~~ and on the ~~generator-side~~remote end of ~~the GSU transformer use Option 7~~line[11]	14a	0.85 per unit of the line nominal voltage at the relay location	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		~~OR~~		
		~~14b~~	~~Simulated line voltage coincident with the highest Reactive Power output achieved during field forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field forcing~~	~~The impedance element shall be set less than the calculated impedance derived from 115% of:~~ ~~(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and~~ ~~(2) Reactive Power output – 100% of the aggregate generation maximum gross Mvar output during field forcing as determined by simulation~~
	~~The same application continues on the next page with a different relay type~~			

[11] If the relay is installed on the generator-side of the GSU transformer use Option 7.

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[4]	~~Pickup~~ Setting Criteria
~~Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. — connected to synchronous generators~~	~~Phase overcurrent supervisory element (50) — associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer or phase time overcurrent relay (51) — installed on the high-side of the GSU transformer~~ ~~If the relay is installed on the generator-side of the GSU transformer use Option 8~~	~~15a~~	~~0.85 per unit of the line nominal voltage~~	~~The overcurrent element shall be set greater than 115% of the calculated current derived from:~~ ~~(1) Real Power output — 100% of the aggregate generation gross MW reported to the Transmission Planner, and~~ ~~(2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor~~
		OR		
		~~15b~~14b	Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage ~~on~~at the ~~high-side terminals~~remote end of the ~~generator step-up transformer~~line prior to field-forcing	The ~~overcurrent~~impedance element shall be set ~~greater~~less than ~~115% of~~ the calculated ~~current~~impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit	Phase ~~directional~~instantaneous overcurrent supervisory element (~~67~~e.g., 50) – associated with current-based, communication-	~~16a~~15a	0.85 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**~~Pickup~~ Setting Criteria**
or generating plant~~.~~ (Elements may also supply generating plant ~~load.~~ loads) – connected to synchronous generators	assisted schemes where the scheme is capable of tripping for loss of communications ~~directional toward the Transmission system~~ installed on the high-side of the GSU transformer and remote end of the line and/or phase ~~directional~~ time overcurrent relay (~~67) – directional toward the Transmission system~~e.g., 51) – installed on the high-side of the GSU transformer ~~If the relay is installed on the generator-side of the GSU transformer use Option 9~~and remote end of the line[12]	15b	Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[12] If the relay is installed on the generator-side of the GSU transformer use Option 8.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**~~Pickup~~ Setting Criteria**
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant load.) – connected to synchronous generators	Phase directional instantaneous overcurrent supervisory element (e.g., 67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system installed on the high-side of the GSU transformer and remote end of the line and/or phase directional time overcurrent relay (e.g., 67) – directional toward the Transmission system installed on the high-side of the GSU transformer and remote end of the line[13]	16a	0.85 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		16b	Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage ~~on~~at the ~~high-side terminals~~remote end of the ~~generator step-up transformer~~line prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
A different application starts on the next page				

[13] If the relay is installed on the generator-side of the GSU transformer use Option 9.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**~~Pickup~~ Setting Criteria**
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~.~~ (Elements may also supply generating plant loads~~.~~) – connected to asynchronous generators only (including inverter-based installations)	Phase distance relay (e.g., 21) – directional toward the Transmission system– installed on the high-side of the GSU transformer ~~If the relay is installed~~ and on the ~~generator-side~~remote end of ~~the GSU transformer use Option 10~~line[14]	17	1.0 per unit of the line nominal voltage at the relay location	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	The same application continues on the next page with a different relay type			

[14] If the relay is installed on the generator-side of the GSU transformer use Option 10.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**~~Pickup~~ Setting Criteria**
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~.~~ (Elements may also supply generating plant loads~~.~~) – connected to asynchronous generators only (including inverter-based installations)	Phase instantaneous overcurrent supervisory element (e.g., 50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer and on the remote end of the line and/or Phase time overcurrent relay (e.g., 51) – installed on the high-side of the GSU transformer ~~If the relay is installed on the generator side of~~ and on the ~~GSU transformer use Option 11~~remote end of the line[15]	18	1.0 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)

Table 1. Relay Loadability Evaluation Criteria				
Application	Relay Type	Option	Bus Voltage[4]	~~Pickup~~ Setting Criteria
	The same application continues on the next page with a different relay type			

[15] If the relay is installed on the generator-side of the GSU transformer use Option 11.

Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~.~~ (Elements may also supply generating plant loads~~.~~) – connected to asynchronous generators only (including inverter-based installations)	Phase directional instantaneous overcurrent supervisory element (e.g., 67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system installed on the high-side of the GSU transformer and on the remote end of the line and/or Phase directional time overcurrent relay (e.g., 67) – installed on the high-side of the GSU transformer ~~If the relay is installed on the generator side of~~ and on the ~~GSU transformer use Option 12~~remote end of the line[16]	19	1.0 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
End of Table 1				

[16] If the relay is installed on the generator-side of the GSU transformer use Option 12.

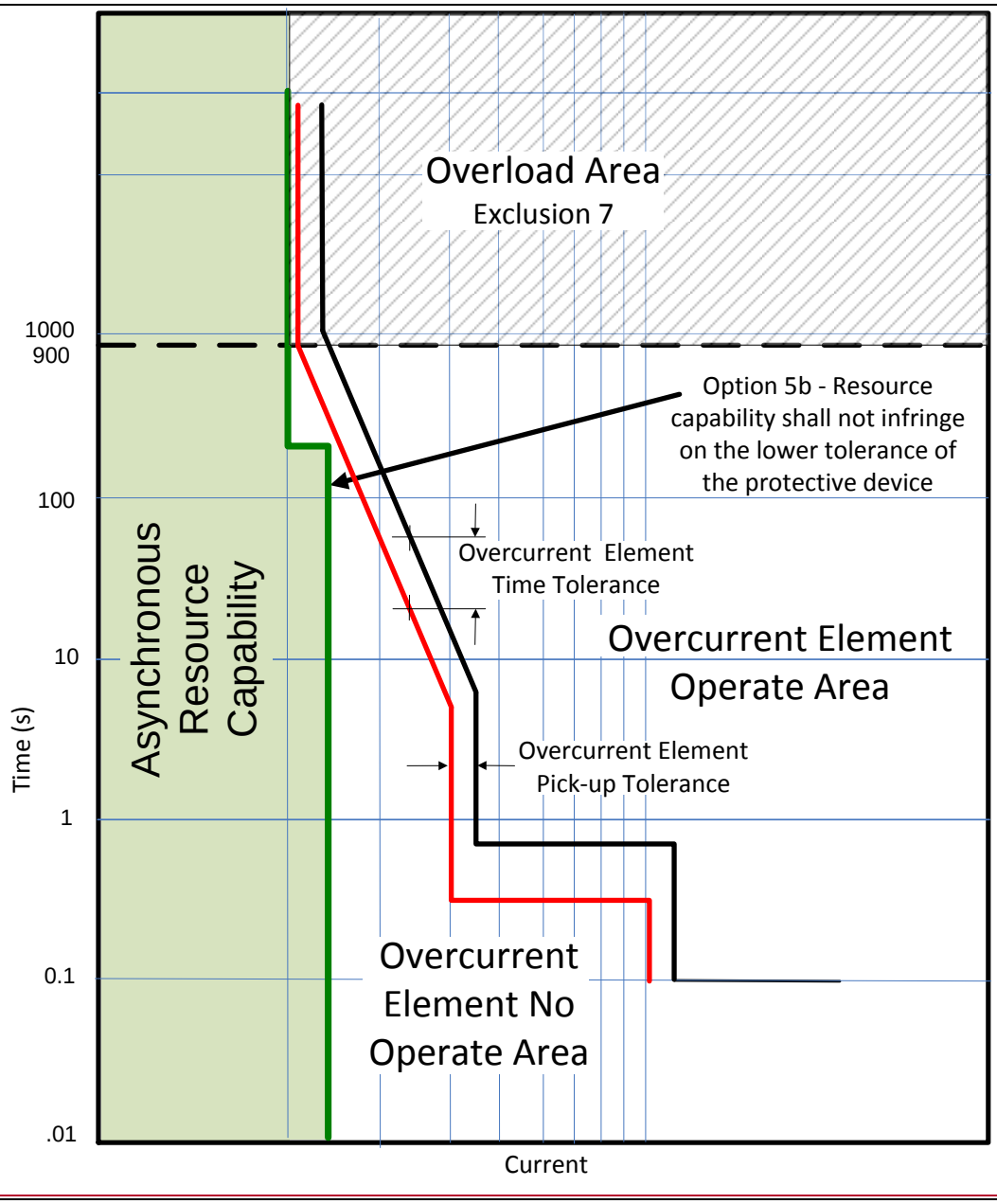


Figure A. This figure is for demonstration of Option 5b and does not mandate a specific type of protective curve or device manufacturer.

PRC-025-~~1~~2 Guidelines and Technical Basis

Introduction

The document, "Considerations for Power Plant and Transmission System Protection Coordination," published by the NERC System Protection and Control Subcommittee (SPCS) provides extensive general discussion about the protective functions and generator performance addressed within this standard. This document was last revised in July ~~2010~~2015.[17]

The basis for the standard's loadability criteria for relays applied at the generator terminals or low-side of the generator step-up (GSU) transformer is the dynamic generating unit loading values observed during the August 14, 2003 blackout, other subsequent system events, and simulations of generating unit response to similar system conditions. The Reactive Power output observed during field-forcing in these events and simulations approaches a value equal to 150 percent of the Real Power (MW) capability of the generating unit when the generator is operating at its Real Power capability. In the SPCS technical reference document, two operating conditions were examined based on these events and simulations: (1) when the unit is operating at rated Real Power in MW with a level of Reactive Power output in Mvar which is equivalent to 150 percent times the rated MW value (representing some level of field-forcing) and (2) when the unit is operating at its declared low active Real Power operating limit (e.g., 40 percent of rated Real Power) with a level of Reactive Power output in Mvar which is equivalent to 175 percent times the rated MW value (representing some additional level of field-forcing).

Both conditions noted above are evaluated with the GSU transformer high-side voltage at 0.85 per unit. These load operating points are believed to be conservatively high levels of Reactive Power out of the generator with a 0.85 per unit high-side voltage which was based on these observations. However, for the purposes of this standard it was determined that the second load point (40 percent) offered no additional benefit and only increased the complexity for an entity to determine how to comply with the standard. Given the conservative nature of the criteria, which may not be achievable by all generating units, an alternate method is provided to determine the Reactive Power output by simulation. Also, to account for Reactive Power losses in the GSU transformer, a reduced level of output of 120 percent times the rated MW value is provided for relays applied at the high-side of the GSU transformer and on Elements that connect a GSU transformer to the Transmission system and are used exclusively to export energy directly from a BES generating unit or generating plant.

The phrase, "while maintaining reliable fault protection" in Requirement R1, describes that the Generator Owner, Transmission Owner, and Distribution Provider is to comply with this standard while achieving its desired protection goals. Load-responsive protective relays, as addressed within this standard, may be intended to provide a variety of backup protection functions, both within the generating unit or generating plant and on the Transmission system, and this standard

[17] ~~http://www.nerc.com/docs/pc/spctf/Gen%20Prot%20Coord%20Rev1%20Final%2007-30-2010.pdf~~
http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Gen%20Prot%20Coordination%20Technical%20Reference%20Document.pdf

is not intended to result in the loss of these protection functions. Instead, it is suggested that the Generator Owner, Transmission Owner, and Distribution Provider consider both the requirement within this standard and its desired protection goals, and perform modifications to its protective relays or protection philosophies as necessary to achieve both.
For example, if the intended protection purpose is to provide backup protection for a failed Transmission breaker, it may not be possible to achieve this purpose while complying with this standard if a simple mho relay is being used. In this case, it may be possible to meet this purpose by replacing the legacy relay with a modern advanced-technology relay that can be set using functions such as load encroachment. It may otherwise be necessary to reconsider whether this is an appropriate method of achieving protection for the failed Transmission breaker, and whether this protection can be better provided by, for example, applying a breaker failure relay with a transfer trip system.

Requirement R1 establishes that the Generator Owner, Transmission Owner, and Distribution Provider must understand the applications of Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria ("Table 1") in determining the settings that it must apply to each of its load-responsive protective relays to prevent an unnecessary trip of its generator during the system conditions anticipated by this standard.

Applicability

To achieve the reliability objective of this standard it is necessary to include all load-responsive protective relays that are affected by increased generator output in response to system disturbances. This standard is therefore applicable to relays applied by the Generator Owner, Transmission Owner, and Distribution Provider at the terminals of the generator, GSU transformer, unit auxiliary transformer (UAT), Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, and Elements utilized in the aggregation of dispersed power producing resources.

The Generator Owner's interconnection facility (in some cases labeled a "transmission Facility" or "generator leads") consists of Elements between the GSU transformer and the interface with the portion of the Bulk Electric System (BES) where Transmission Owners take over the ownership. This standard does not use the industry recognized term "generator interconnection Facility" consistent with the work of Project 2010-07 (Generator Requirements at the Transmission Interface), because the term generator interconnection Facility implies ownership by the Generator Owner. Instead, this standard refers to these Facilities as "Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant" to include these Facilities when they are also owned by the Transmission Owner or Distribution Provider. The load-responsive protective relays in this standard for which an entity shall be in compliance is dependent on the location and the application of the protective functions. Figures 1, 2, and 3 illustrate various generator interface connections with the Transmission system.

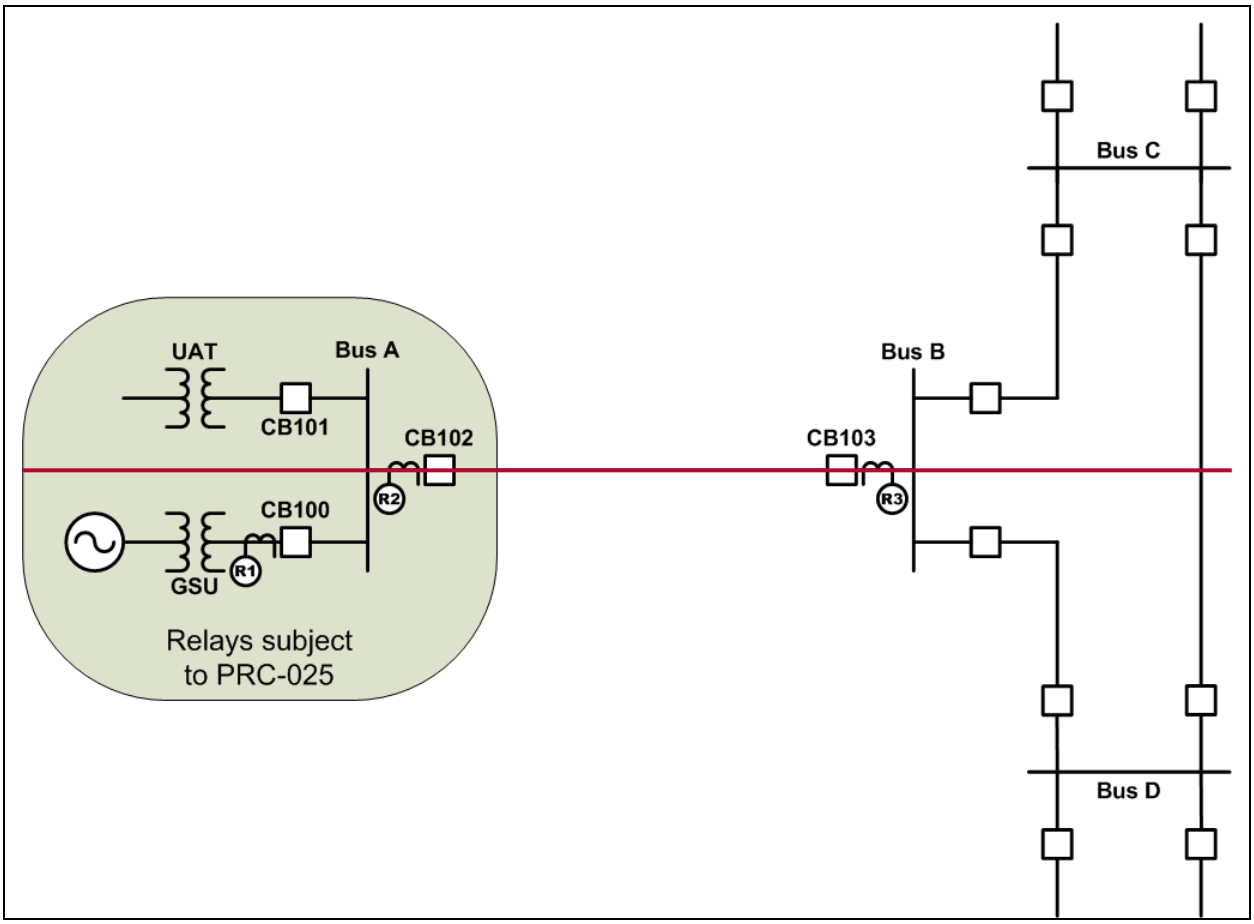
Figure 1

Figure 1 is a single (or set) of generators connected to the Transmission system through a radial line that is used exclusively to export energy directly from a BES generating unit or generating plant to the network. The protective relay R1 located on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the relaying located at Bus A and in some cases Bus B. Under this application, relay R1 would apply the loadability requirement in PRC-025-~~1~~2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

The protective relay R2 located on the incoming source breaker CB102 to the generating plant applies relaying that primarily protects the line by using line differential relaying from Bus A to B and also provides backup protection to the transmission relaying at Bus B. In this case, the relay function that provides line protection would apply the loadability requirement in PRC-025-~~1~~2 and an appropriate option for the application from Table 1 (e.g., 15a, 15b, 16a, 16b, 18, and 19) for phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications. The backup protective function would apply the requirement in the PRC-025-~~1~~2 standard using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

Since Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are applicable to the standard, the loadability for relays applied on these Elements as shown in the shaded area of Figure 1 (i.e., CB102 and CB103) must be considered. If relay R2 or R3 is set with an element directional toward the transmission system (e.g., Buses B, C and D) or are non-directional, the relay would be affected by increased generator output in response to system disturbances and must meet the loadability setting criteria described in the standard. If relay R2 or R3 is set with an element directional toward the generator (e.g., Bus A), the relay would not be affected by increased generator output in response to system disturbances; therefore, the entity would not be required to apply the loadability setting criteria described in this standard.

~~In this particular case, the applicable responsible entity's directional relay R3 located on breaker CB103 at Bus B looking toward Bus A (i.e., generation plant) is not included in either loadability standard (i.e., PRC-023 or PRC-025) since it is not affected by increased generator output in response to system disturbances described in this standard or by increased transmission system loading described in PRC-023. Any protective element set to protect in the direction from Bus A to B is included within the PRC-025-1 standard. PRC-025-1 is applicable to Relay R3, for example, if the relay is applied and set to trip for a reverse element directional toward the Transmission system.~~


UAT
Bus A
CB101
CB102
CB100
R2
R1
GSU
Relays subject
to PRC-025
Bus B
CB103
R3
Bus C
Bus D

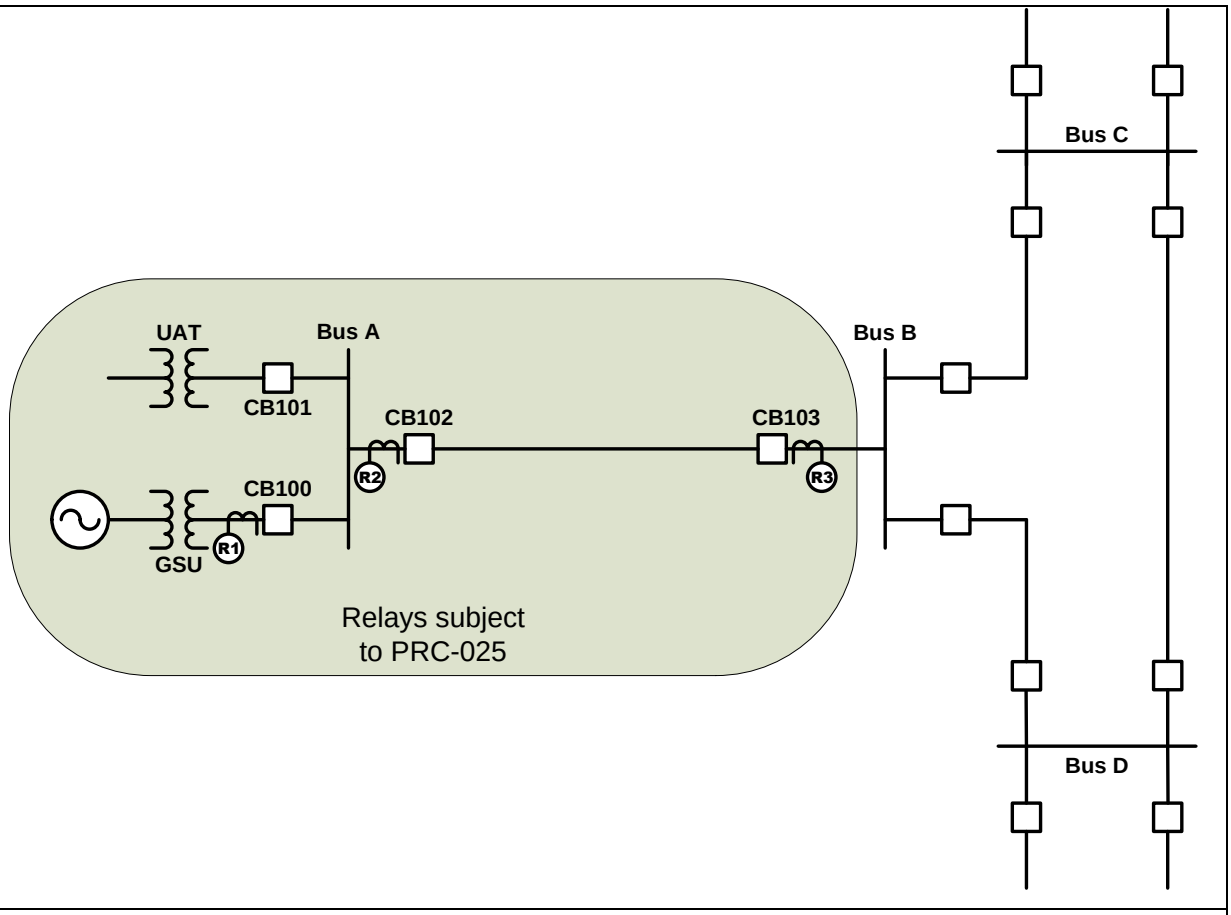


Figure 1. Generation exported through a single radial line.

Figure 2

Figure 2 is an example of a single (or set) of generators connected to the Transmission system through multiple lines that are used exclusively to export energy directly from a BES generating unit or generating plant to the network. The protective relay R1 on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the Transmission relaying located at Bus A and in some cases Bus B. Under this application, relay R1 would apply the loadability requirement in PRC-025-~~1~~2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

The protective relays R2 and R3 located on the incoming source breakers CB102 and CB103 to the generating plant applies relaying that primarily protects the line from Bus A to B and also provides backup protection to the transmission relaying at Bus B. In this case, the relay function that provides line protection would apply the loadability requirement in PRC-025-~~1~~2 and an appropriate option for the application from Table 1 (e.g., Options 15a, 15b, 16a, 16b, 18, and 19) for phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current

differential) where the scheme is capable of tripping for loss of communications. The backup protective function would apply the requirement in the PRC-025-~~1~~2 standard using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

~~In this particular case, the applicable responsible entity's directional relay R4 and R5 located on the breakers CB104 and CB105, respectively at Bus B looking into the generation plant are not included in either loadability standard (i.e., PRC-023 or PRC-025) since they are not subject to the stressed loading requirements described in the standard or by increased transmission system loading described in PRC-023. Any protective element set to protect in the direction from Bus A to B is included within the PRC-025-1 standard. PRC-025-1 is applicable to Relay R4 and R5, for example, if the relays are applied and set to trip for a reverse element directional toward the Transmission system.~~

Since Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are applicable to the standard, the loadability for relays applied on these Elements as shown in the shaded area of Figure 2 (i.e., CB102, CB103, CB104, and CB105) must be considered. If relay R2, R3, R4, or R5 is set with an element directional toward the transmission system (e.g., Buses B, C and D) or are non-directional, the relay would be affected by increased generator output in response to system disturbances and must meet the loadability setting criteria described in the standard. If relay R2, R3, R4, or R5 is set with an element directional toward the generator (e.g., Bus A), the relay would not be affected by increased generator output in response to system disturbances; therefore, the entity would not be required to apply the loadability setting criteria described in this standard.

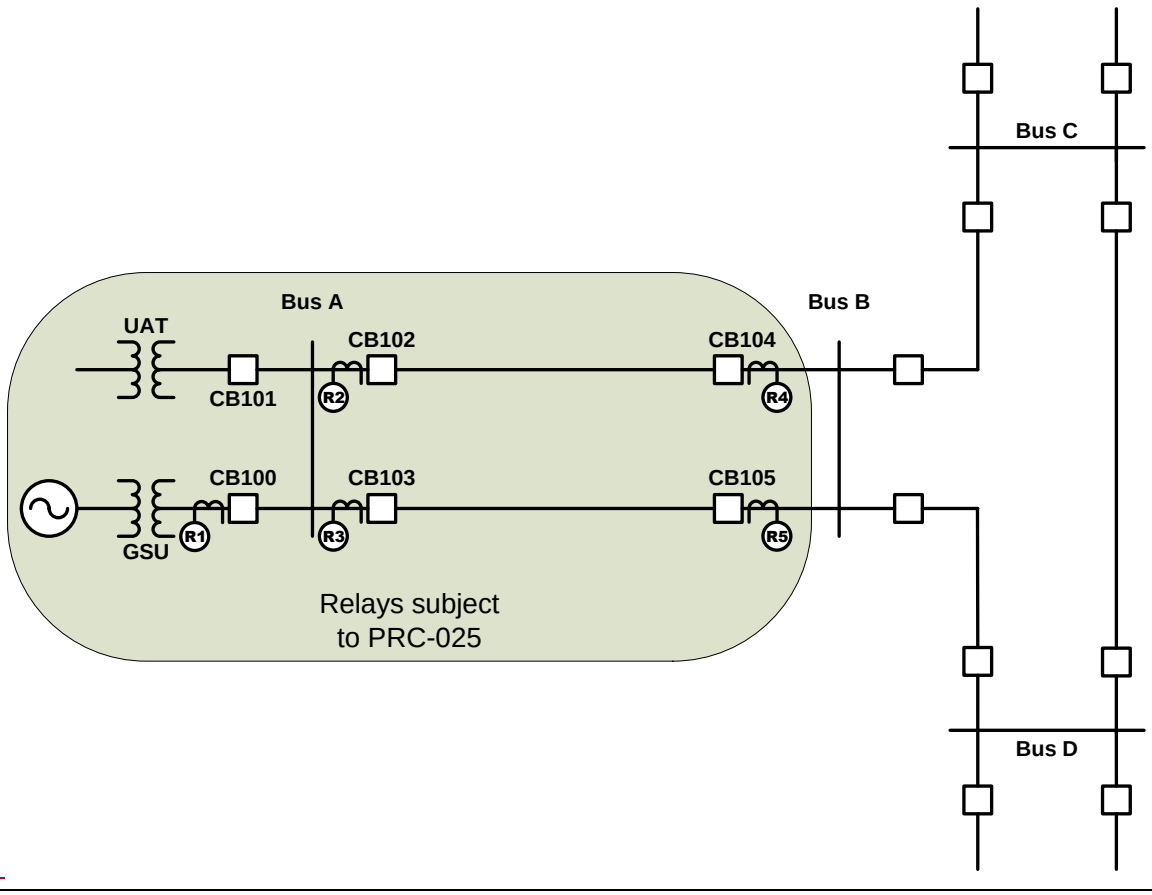


Figure 2. Generation exported through multiple radial lines.

Figure 3

Figure 3 is example a single (or set) of generators exporting power dispersed through multiple lines to the Transmission system through a network. The protective relay R1 on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the Transmission relaying located at Bus A and in some cases Bus C or Bus D. Under this application, relay R1 would apply the applicable loadability requirement in PRC-025-~~1~~2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

Since the lines from Bus A to Bus C and from Bus A to Bus D are part of the transmission network, these lines would not be considered as Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Therefore, the applicable responsible entity would be responsible for the load-responsive protective relays R2 and R3 under the PRC-023 standard. The applicable responsible entity's loadability relays R4 and R5 located on the breakers CB104 and CB105 at Bus C and D are also subject to the requirements of the PRC-023 standard.

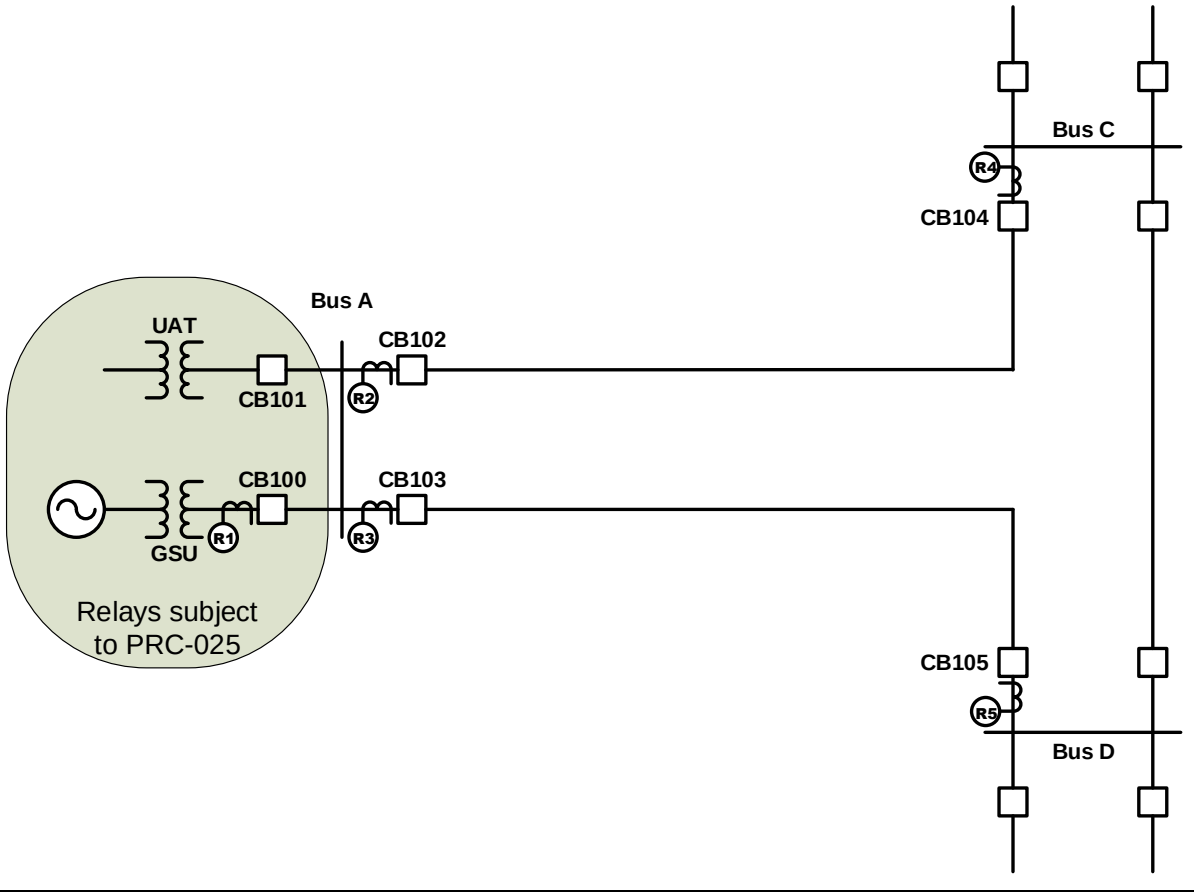


Figure 3. Generation exported through a network.

Elements utilized in the aggregation of dispersed power producing resources (in some cases referred to as a "collector system") consist of the Elements between individual generating units and the common point of interconnection to the Transmission system.

This standard is also applicable to the UATs that supply station service power to support the on-line operation of generating units or generating plants. These transformers are variably referred to as station power, unit auxiliary transformer(s), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Inclusion of these transformers satisfies a directive in FERC Order No. 733, paragraph 104, which directs NERC to include in this standard a loadability requirement for relays used for overload protection of the UAT(s) that supply normal station service for a generating unit.

Synchronous Generator Performance

When a synchronous generator experiences a depressed voltage, the generator will respond by increasing its Reactive Power output to support the generator terminal voltage. This operating condition, known as "field-forcing," results in the Reactive Power output exceeding the steady-state capability of the generator and may result in operation of generation system load-responsive protective relays if they are not set to consider this operating condition. The ability of

the generating unit to withstand the increased Reactive Power output during field-forcing is limited by the field winding thermal withstand capability. The excitation limiter will respond to begin reducing the level of field-forcing in as little as one second, but may take much longer, depending on the level of field-forcing given the characteristics and application of the excitation system. Since this time may be longer than the time-delay of the generator load-responsive protective relay, it is important to evaluate the loadability to prevent its operation for this condition.

The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the GSU transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage. The criteria established within Table 1 are based on 0.85 per unit of ~~Transmission system~~the line nominal voltage. This voltage was widely observed during the events of August 14, 2003, and was determined during the analysis of the events to represent a condition from which the System may have recovered, had ~~not~~ other undesired behavior not occurred.

The dynamic load levels specified in Table 1 under column "~~Pickup~~ Setting Criteria" are representative of the maximum expected apparent power during field-forcing with the Transmission system voltage at 0.85 per unit, for example, at the high-side of the GSU transformer. These values are based on records from the events leading to the August 14, 2003 blackout, other subsequent System events, and simulations of generating unit responses to similar conditions. Based on these observations, the specified criteria represent conservative but achievable levels of Reactive Power output of the generator with a 0.85 per unit high-side voltage at the point of interconnection.

The dynamic load levels were validated by simulating the response of synchronous generating units to depressed Transmission system voltages for 67 different generating units. The generating units selected for the simulations represented a broad range of generating unit and excitation system characteristics as well as a range of Transmission system interconnection characteristics. The simulations confirmed, for units operating at or near the maximum Real Power output, that it is possible to achieve a Reactive Power output of 1.5 times the rated Real Power output when the Transmission system voltage is depressed to 0.85 per unit. While the simulations demonstrated that all generating units may not be capable of this level of Reactive Power output, the simulations confirmed that approximately 20 percent of the units modeled in the simulations could achieve these levels. On the basis of these levels, Table 1, Options 1a (i.e., 0.95 per unit) and 1b (i.e., 0.85 per unit), for example, are based on relatively simple, but conservative calculations of the high-side nominal voltage. In recognition that not all units are capable of achieving this level of output Option 1c (i.e., simulation) was developed to allow the Generator Owner, Transmission Owner, or Distribution Provider to simulate the output of a generating unit when the simple calculation is not adequate to achieve the desired protective relay setting.

Dispersed Generation

This standard is applicable to dispersed generation such as wind farms and solar arrays. The intent of this standard is to ensure the aggregate facility as defined above will remain on-line

during a system disturbance; therefore, all output load-responsive protective ~~elements~~relays associated with the facility are included in PRC-~~-~~025.

Dispersed power producing resources with aggregate capacity greater than 75 MVA (gross aggregate nameplate rating) utilizing a system designed primarily for aggregating capacity, connected at a common point at a voltage of 100 kV or above are included in PRC-025-~~1~~2. Load-responsive protective relays that are applied on Elements that connect these individual generating units through the point of interconnection with the Transmission system are within the scope of PRC-025-~~1~~2. For example, feeder overcurrent relays and feeder step-up transformer overcurrent relays (see Figure 5) are included because these relays are challenged by generator loadability.

In the case of solar arrays where there are multiple voltages utilized in converting the solar panel DC output to a 60Hz AC waveform, the "terminal" is defined at the 60Hz AC output of the inverter-solar panel combination.

Asynchronous Generator Performance

Asynchronous generators~~, however, do not have excitation systems and~~ will not respond to a disturbance with the same magnitude of apparent power that a synchronous generator will respond. Asynchronous generators, though, will support the system during a disturbance. Inverter-based generators will provide Real Power and Reactive Power (depending on the installed capability and regional grid code requirements) and may even provide a faster Reactive Power response than a synchronous generator. The magnitude of this response may slightly exceed the steady-state capability of the inverter but only for a short duration before ~~a crowbar function~~limiter functions will activate. Although induction generators will not inherently supply Reactive Power, induction generator installations may include static and/or dynamic reactive devices, depending on regional grid code requirements. These devices also may provide Real Power during a voltage disturbance. Thus, tripping asynchronous generators may exacerbate a disturbance.

Inverters, including wind turbines (i.e., Types 3 and 4) and photovoltaic solar, are commonly available with 0.90 power factor capability. This calculates to an apparent power magnitude of 1.11 per unit of rated MW.

Similarly, induction generator installations, including Type 1 and Type 2 wind turbines, often include static and/or dynamic reactive devices to meet grid code requirements and may have apparent power output similar to inverter-based installations; therefore, it is appropriate to use the criteria established in the Table 1 (i.e., Options 4, 5, 6, 10, 11, 12, 17, 18, and 19) for asynchronous generator installations.

Synchronous Generator Simulation Criteria

The Generator Owner, Transmission Owner, or Distribution Provider who elects a simulation option to determine the synchronous generator performance on which to base relay settings may simulate the response of a generator by lowering the Transmission system voltage ~~on~~at the

remote end of the line or at the high-side of the GSU transformer~~.~~ (as prescribed by the Table 1 criteria). This can be simulated by means such as modeling the connection of a shunt reactor ~~on~~at the ~~Transmission system to lower~~remote end of the line or at the GSU transformer high-side to lower the voltage to 0.85 per unit prior to field-forcing. The resulting step change in voltage is similar to the sudden voltage depression observed in parts of the Transmission system on August 14, 2003. The initial condition for the simulation should represent the generator at 100 percent of the maximum gross Real Power capability in MW as reported to the Transmission Planner. The simulation is used to determine the Reactive Power and voltage to be used to calculate relay ~~pickup~~ setting limits. The Reactive Power value obtained by simulation is the highest simulated level of Reactive Power achieved during field-forcing. The voltage value obtained by simulation is the simulated voltage coincident with the highest Reactive Power achieved during field-forcing. These values of Reactive Power and voltage correspond to the minimum apparent impedance and maximum current observed during field-forcing.

Phase Distance Relay – Directional Toward Transmission System (e.g., 21)

Generator phase distance relays that are directional toward the Transmission system, whether applied for the purpose of primary or backup GSU transformer protection, external system backup protection, or both, were noted during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generating units or generating plants, ~~contributing~~which contributed to the scope of that disturbance. Specifically, eight generators are known to have been tripped by this protection function. These options establish criteria for phase distance relays that are directional toward the Transmission system to help assure that generators, to the degree possible, will provide System support during disturbances in an effort to minimize the scope of those disturbances.

The phase distance relay that is directional toward the Transmission system measures impedance derived from the quotient of generator terminal voltage divided by generator stator current.

Section 4.6.1.1 of IEEE C37.102-2006, "Guide for AC Generator Protection," describes the purpose of this protection as follows (emphasis added):

> *"The distance relay applied for this function is intended to isolate the generator from the power system for a fault* ***that is not cleared by the transmission line breakers.*** *In some cases this relay is set with a very long reach. A condition that causes the generator voltage regulator to boost generator excitation for a sustained period may result in the system apparent impedance, as monitored at the generator terminals, to fall within the operating characteristics of the distance relay. Generally, a distance relay setting of 150% to 200% of the generator MVA rating at its rated power factor has been shown to provide good coordination for stable swings, system faults involving in-feed, and* ***normal loading conditions.*** *However, this setting may also result in failure of the relay to operate for some line faults where the line relays fail to*

clear. It is recommended that the setting of these relays be evaluated between the generator protection engineers and the system protection engineers ***to optimize coordination while still protecting the turbine generator****. Stability studies may be needed to help determine a set point to optimize protection and coordination. Modern excitation control systems include overexcitation limiting and protection devices to protect the generator field, but the time delay before they reduce excitation is several seconds. In distance relay applications for which the voltage regulator action could cause an incorrect trip, consideration should be given to reducing the reach of the relay and/or coordinating the tripping time delay with the time delays of the protective devices in the voltage regulator. Digital multifunction relays equipped with load encroachment binders [sic] can prevent misoperation for these conditions.* ***Within its operating zone, the tripping time for this relay must coordinate with the longest time delay for the phase distance relays on the transmission lines connected to the generating substation bus.*** *With the advent of multifunction generator protection relays, it is becoming more common to use two-phase distance zones. In this case, the second zone would be set as previously described. When two zones are applied for backup protection, the first zone is typically set to see the substation bus (120% of the GSU transformer). This setting should be checked for coordination with the zone-1 element on the shortest line off of the bus. The normal zone-2 time-delay criteria would be used to set the delay for this element. Alternatively, zone-1 can be used to provide high-speed protection for phase faults, in addition to the normal differential protection, in the generator and iso-phase bus with partial coverage of the GSU transformer. For this application, the element would typically be set to 50% of the transformer impedance with little or no intentional time delay. It should be noted that it is possible that this element can operate on an out-of-step power swing condition and provide misleading targeting."*

If a mho phase distance relay that is directional toward the Transmission system cannot be set to maintain reliable fault protection and also meet the criteria in accordance with Table 1, there may be other methods available to do both, such as application of blinders to the existing relays, implementation of lenticular characteristic relays, application of offset mho relays, or implementation of load encroachment characteristics. Some methods are better suited to improving loadability around a specific operating point, while others improve loadability for a wider area of potential operating points in the R-X plane. The operating point for a stressed System condition can vary due to the pre-event system conditions, severity of the initiating event, and generator characteristics such as Reactive Power capability.

For this reason, it is important to consider the potential implications of revising the shape of the relay characteristic to obtain a longer relay reach, as this practice may result in a relay characteristic that overlaps the capability of the generating unit when operating at a Real Power output level other than 100 percent of the maximum Real Power capability. Overlap of the relay characteristic and generator capability could result in tripping the generating unit for a loading condition within the generating unit capability. The examples in Appendix E of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document illustrate the potential for, and need to avoid, encroaching on the generating unit capability.

Phase Instantaneous Overcurrent Relay (e.g., 50)

The 50 element is a non-directional overcurrent element that typically has no intentional time delay. The primary application is for close-in high current faults where high speed operation is required or preferred. The instantaneous overcurrent elements are subject to the same loadability issues as the time overcurrent elements referenced in this standard.

Phase Time Overcurrent Relay (e.g., 51)

See ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function. Note that the ~~Table 1~~ setting criteria established within the Table 1 options ~~differ~~differs from ~~section 3.9.2 of~~ the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the Table 1 setting criteria are based on the maximum expected generator Real Power output based on whether the generator ~~operates~~is a synchronous or asynchronous unit.

Phase Time Overcurrent Relay – Voltage-Restrained (e.g., 51V-R)

Phase time overcurrent voltage-restrained relays (e.g., 51V-R), which change their sensitivity as a function of voltage, whether applied for the purpose of primary or backup GSU transformer protection, for external system phase backup protection, or both, were noted, during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generating units or generating plants, contributing to the scope of that disturbance. Specifically, 20 generators are known to have been tripped by voltage-restrained and voltage-controlled protection functions together. These protective functions are variably referred to by IEEE function numbers 51V, 51R, 51VR, 51V/R, 51V-R, or other terms. ~~See section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.~~

~~**Phase Time Overcurrent Relay – Voltage Controlled (51V-C)**~~

~~Phase time overcurrent voltage-controlled relays (51V-C), enabled as a function of voltage, are variably referred to by IEEE function numbers 51V, 51C, 51VC, 51V/C, 51V-C, or other terms. See section 3.10 of the~~See Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.

Phase Time Overcurrent Relay – Voltage Controlled (e.g., 51V-C)

Phase time overcurrent voltage-controlled relays (e.g., 51V-C), enabled as a function of voltage, are variably referred to by IEEE function numbers 51V, 51C, 51VC, 51V/C, 51V-C, or other terms. See Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.

Phase Directional ~~Time~~ Overcurrent Relay – Directional Toward Transmission System (e.g., 67)

See ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of the phase time overcurrent protection function. The basis for setting directional and non-directional ~~time~~ overcurrent relays is similar. Note that the ~~Table 1setting~~setting criteria established within the Table 1 options ~~differ~~differs from ~~section 3.9.2~~ of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the Table 1 setting criteria are based on the maximum expected generator Real Power output based on whether the generator ~~operates~~is a synchronous or asynchronous unit.

Table 1, Options

Introduction

The margins in the Table 1 options are based on guidance found in the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the GSU transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage.

Relay Connections

Figures 4 and 5 below illustrate the connections for each of the Table 1 options provided in PRC-025-~~1~~2, Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria.

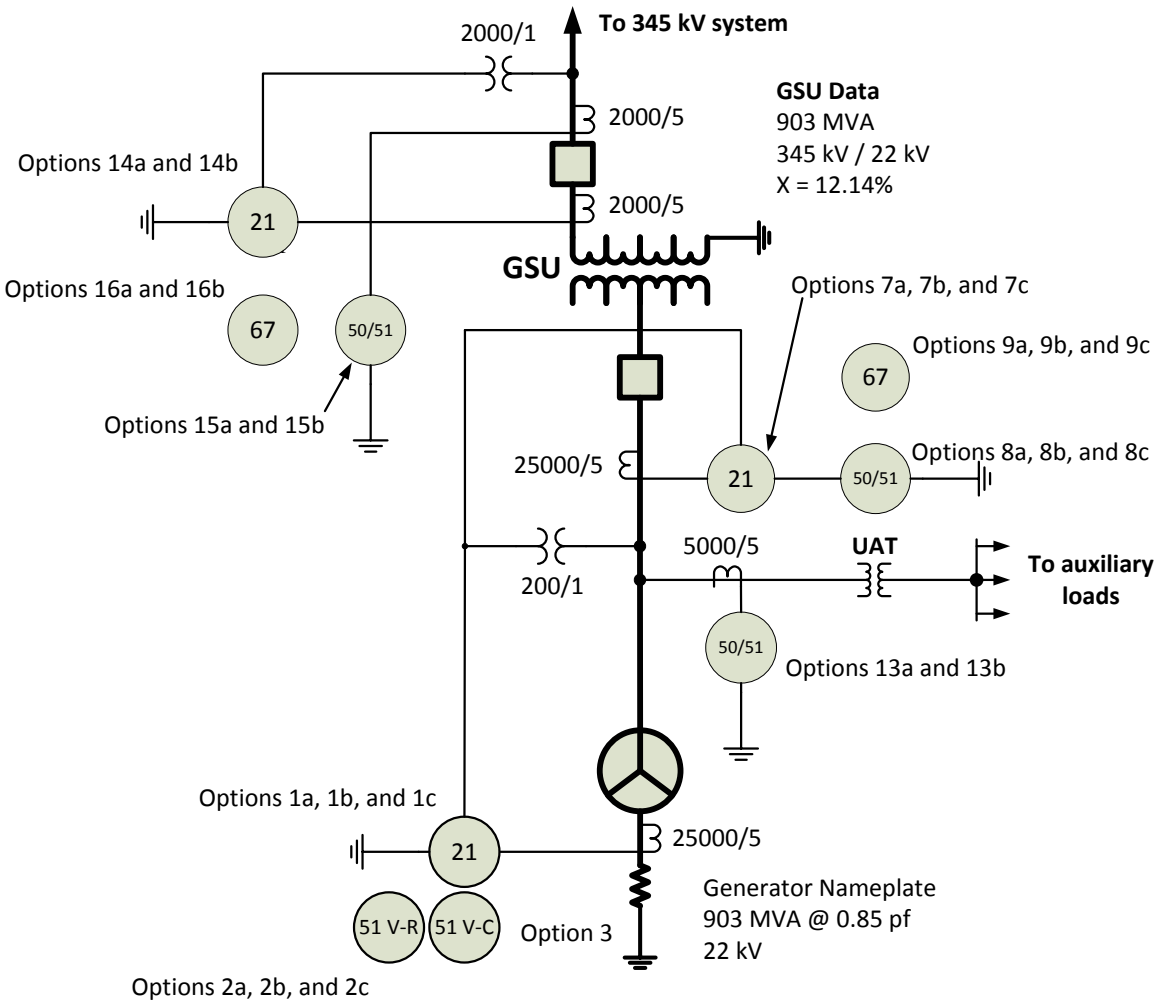


Figure 4. Relay Connection for corresponding synchronous options.

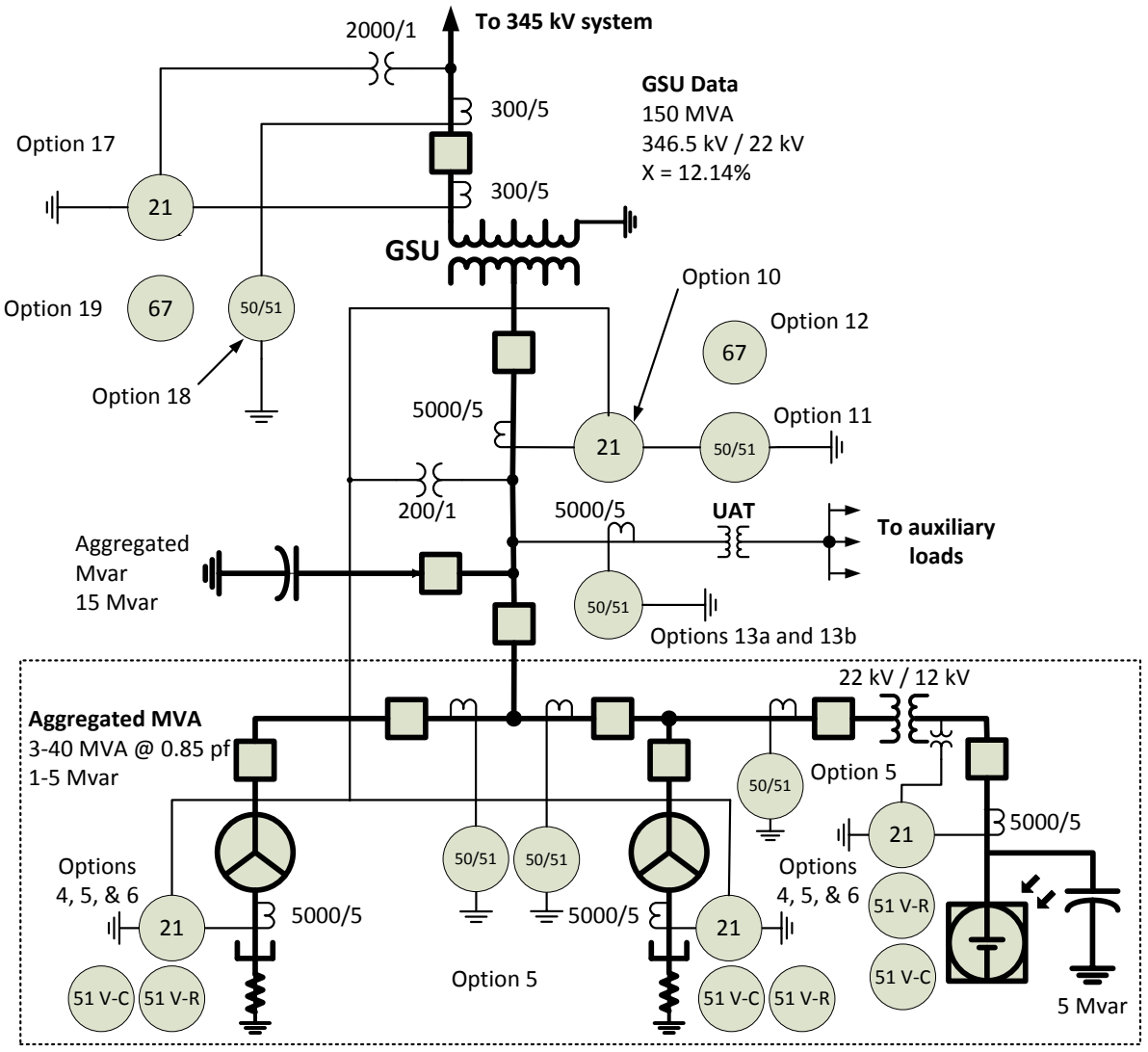


Figure 5. Relay Connection for corresponding asynchronous options including inverter-based installations.

Synchronous Generators Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Options 1a, 1b, and 1c)

Table 1, Options 1a, 1b, and 1c, are provided for assessing loadability for synchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are based on guidance found in ~~section 3.1~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 1a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This ~~is the simplest~~

calculation ~~that approximates~~is a straightforward way to approximate the stressed system conditions.

Option 1b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer ~~and accounts for~~as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more ~~involved, more~~ in-depth and precise method for setting of the impedance element than Option 1a.

Option 1c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the impedance element overall.

For Options 1a and 1b, the impedance element ~~is~~shall be set less than the calculated impedance derived from ~~115percent~~115 percent of both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 1c, the impedance element ~~is~~shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Synchronous Generators Phase ~~Time~~ Overcurrent Relay – (e.g., 50, 51, or 51V-R – Voltage~~-~~ Restrained ~~(51V-R~~) (Options 2a, 2b, and 2c)

Table 1, Options 2a, 2b, and 2c, are provided for assessing loadability for synchronous generators applying phase ~~time~~ overcurrent relays (e.g., 50 or 51) or voltage-restrained (e.g., 51V-R) which ~~change their~~changes its sensitivity as a function of voltage ("voltage-restrained"). These margins are based on guidance found in ~~section 3.10~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 2a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This ~~is the simplest~~ calculation ~~that approximates~~is a straightforward way to approximate the stressed system conditions.

Option 2b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer

is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer ~~and accounts~~as well as for the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more ~~involved, more~~in-depth and precise method for setting of the overcurrent element than Option 2a.

Option 2c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 2a and 2b, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 2c, the overcurrent element ~~is~~shall be set greater than the calculated current derived from 115 percent of both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Synchronous Generators Phase Time Overcurrent Relay – Voltage Controlled (e.g., 51V-C) (Option 3)

Table 1, Option 3, is provided for assessing loadability for synchronous generators applying phase time overcurrent relays which are enabled as a function of voltage ("voltage-controlled"). These margins are based on guidance found in ~~section 3.10~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 3 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 3, the voltage control setting ~~is~~shall be set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

Asynchronous Generators Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 4)

Table 1, Option 4 is provided for assessing loadability for asynchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are based on guidance found in ~~section 3.1~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 4 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

~~Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators;~~

~~the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.~~

For Option 4, the impedance element ~~is~~shall be set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Asynchronous Generators Phase ~~Time~~ Overcurrent Relay – (e.g., 50, 51, or 51V-R – Voltage~~-~~ Restrained ~~(51V-R) (Option 5)~~ (Options 5a and 5b))

Table 1, Option ~~5~~5a is provided for assessing loadability for asynchronous generators applying phase ~~time~~ overcurrent relays (e.g., 50 or 51) or voltage-restrained (e.g., 51V-R) which ~~change their~~changes its sensitivity as a function of voltage ("voltage-restrained"). These margins are based on guidance found in ~~section 3.10~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option ~~5~~5a calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer

~~times~~, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

~~Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.~~

For Option ~~5~~5a, the overcurrent element ~~is~~shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

For Option 5b, the overcurrent element shall be set to exceed the maximum capability of the asynchronous resource and applicable equipment (e.g., windings, power electronics, cables, or bus). This is determined by summing the total current capability of the generation equipment behind the overcurrent element and any static or dynamic Reactive Power devices that contribute to the power flow through the overcurrent element. The overcurrent element shall be set to not infringe upon the resource capability with worst case documented tolerances applied to the setting. Figure A illustrates that the overcurrent element does not infringe upon the asynchronous resource capability. The upper hashed area of Figure A represents Exclusion 7.

Asynchronous Generator Phase Time Overcurrent Relays – Voltage Controlled (e.g., 51V-C) (Option 6)

Table 1, Option 6, is provided for assessing loadability for asynchronous generators applying phase time overcurrent relays which are enabled as a function of voltage ("voltage-controlled"). These margins are based on guidance found in ~~section 3.10~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 6 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 6, the voltage control setting ~~is~~shall be set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

Generator Step-up Transformer (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (e.g., 21) (Options 7a, 7b, and 7c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. These margins are based on guidance found in ~~section 3.1~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Options 7a, 7b, and 7c, are provided for assessing loadability ~~for GSU transformers applying~~of phase distance relays that are directional toward the Transmission system ~~on synchronous generators that are~~and connected to the generator-side of the GSU transformer of a synchronous generator. ~~Where~~For applications where the relay is connected on the high-side of the GSU transformer, use Option 14.

Option 7a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This ~~is the simplest~~ calculation ~~that approximates~~is a straightforward way to approximate the stressed system conditions.

Option 7b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on ~~a~~the 0.85 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~and accounts for~~, as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more ~~involved, more~~in-depth and precise method for setting ~~of~~ the impedance element than Option 7a.

Option 7c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more ~~involved, more~~in-depth and precise method for setting ~~of~~ the ~~overcurrent~~impedance element ~~overall~~than Options 7a or 7b.

For Options 7a and 7b, the impedance element ~~is~~shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate

generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value~~,~~ (derived from the generator nameplate MVA rating at rated power factor~~.~~).

For Option 7c, the impedance element ~~is~~shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase ~~Time~~ Overcurrent Relay (e.g., 50 or 51) (Options 8a, 8b and 8c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within the Table 1 options differs from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 8a, 8b, and 8c, are provided for assessing loadability of phase overcurrent relays that are connected to the generator-side of the GSU transformer of a synchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 15.

Option 8a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 8b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on the 0.85 per unit nominal voltage, at the high-side terminals of the GSU transformer, as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more in-depth and precise method for setting the overcurrent element than Option 8a.

Option 8c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more in-depth and precise method for setting the overcurrent element than Options 8a or 8b.

For Options 8a and 8b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value (derived from the generator nameplate MVA rating at rated power factor).

For Option 8c, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Options 9a, 9b and 9c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within ~~these~~the Table 1 options ~~differ~~differs from ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. ~~Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.~~

~~Table 1, Options 8a, 8b, and 8c, are provided for assessing loadability for GSU transformers applying phase time overcurrent relays on synchronous generators that are connected to the generator side of the GSU transformer of a synchronous generator. Where the relay is connected on the high-side of the GSU transformer, use Option 15.~~

~~Option 8a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying a 0.95 per unit nominal voltage at the high-side terminals of the GSU transformer times the GSU transformer turns ratio (excluding the impedance). This is the simplest calculation that approximates the stressed system conditions.~~

~~Option 8b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer and accounts for the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more involved, more precise setting of the impedance element than Option 8a.~~

~~Option 8c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.~~

~~For Options 8a and 8b, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW~~

~~capability reported to the Transmission Planner, and Reactive Power output that equates to 150 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor.~~

~~For Option 8c, the overcurrent element~~ ~~is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.~~

~~Generator Step-up Transformer (Synchronous Generators) Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67) (Options 9a, 9b and 9c)~~

~~The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers.~~ ~~Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document.~~ Rather than establishing a uniform ~~setting~~loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 9a, 9b, and 9c, are provided for assessing loadability ~~for GSU transformers applying~~of phase directional ~~time~~ overcurrent relays directional toward the Transmission System that are connected to the generator-side of the GSU transformer of a synchronous generator. ~~Where~~For applications where the relay is connected on the high-side of the GSU transformer, use Option 16.

Option 9a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This ~~is the simplest~~ calculation ~~that approximates~~is a straightforward way to approximate the stressed system conditions.

Option 9b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on ~~a~~the 0.85 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~and accounts for~~, as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more ~~involved, more~~in-depth and precise method for setting ~~of~~ the ~~impedance~~overcurrent element than Option 9a.

Option 9c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more

~~involved, more~~in-depth and precise method for setting ~~of~~ the overcurrent element ~~overall~~than Options 9a or 9b.

For Options 9a and 9b, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value~~,~~ (derived from the generator nameplate MVA rating at rated power factor~~.~~).

For Option 9c, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 10)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Table 1, Option 10 is provided for assessing loadability for GSU transformers applying phase distance relays that are directional toward the Transmission System that are connected to the generator-side of the GSU transformer of an asynchronous generator. These margins are based on guidance found in ~~section 3.1~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. ~~Where~~For applications where the relay is connected on the high-side of the GSU transformer, use Option 17.

Option 10 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This ~~is a simple~~ calculation ~~that approximates~~is a straightforward way to approximate the stressed system conditions.

~~Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.~~

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; hence the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 10, the impedance element ~~is~~shall be set less than the calculated impedance, derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase ~~Time~~ Overcurrent Relay (e.g., 50 or 51) (Option 11)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. ~~The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers.~~ Note that the setting criteria established within ~~these~~the Table 1 options ~~differ~~differs from ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform ~~setting~~loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 11 is provided for assessing loadability ~~for GSU transformers applying~~of phase ~~time~~ overcurrent relays ~~on asynchronous generators~~ that are connected to the generator-side of the GSU transformer~~. Where~~ of an asynchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 18.

Option 11 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This ~~is a simple~~ calculation ~~that approximates~~is a straightforward way to approximate the stressed system conditions.

Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; hence the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

~~the voltage drop due to Reactive Power flow through the GSU transformer is not as significant.~~

~~Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.~~

For Option 11, the overcurrent element ~~is~~shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined

by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Option 12)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within the Table 1 options differs from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 12 is provided for assessing loadability of phase directional overcurrent relays directional toward the Transmission System that are connected to the generator-side of the GSU transformer of an asynchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 19.

Option 12 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; hence the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 12, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

~~Generator Step-up Transformer (Asynchronous Generators) Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67) (Option 12)~~

~~The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers.~~ ~~Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.~~

~~Table 1, Option 12 is provided for assessing loadability for GSU transformers applying phase directional time overcurrent relays directional toward the Transmission System on asynchronous generators that are connected to the generator-side of the GSU transformer of an asynchronous generator. Where the relay is connected on the high-side of the GSU transformer, use Option 19.~~
~~Option 12 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer.~~ ~~The generator bus voltage is calculated by multiplying a 1.0 per unit nominal voltage at the high-side terminals of the GSU transformer times the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.~~
~~Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage.~~ ~~Asynchronous generators do not produce as much Reactive Power as synchronous generators;~~ ~~the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.~~
~~For Option 12, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices.~~ ~~This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.~~

Unit Auxiliary Transformers Phase ~~Time~~ Overcurrent Relay (e.g., 50 or 51) (Options 13a and 13b)

In FERC Order No. 733, paragraph 104, directs NERC to include in this standard a loadability requirement for relays used for overload protection of the UAT that supply normal station service for a generating unit. For the purposes of this standard, UATs provide the overall station power to support the unit at its maximum gross operation.

Table 1, Options 13a and 13b provide two options for addressing phase ~~time~~ overcurrent relaying applied at the high-side of UATs. The transformer high-side winding may be directly connected to the transmission grid or at the generator isolated phase bus (IPB) or iso-phase bus. Phase ~~time~~ overcurrent relays applied at the high-side of the UAT that remove the transformer from service resulting in an immediate (e.g., via lockout or auxiliary tripping relay operation) or consequential trip of the associated generator are to be compliant with the relay setting criteria in this standard.

Due to the complexity of the application of low-side overload relays for single or multi-winding transformers, phase ~~time~~ overcurrent relaying applied ~~to~~at the low-side of the UAT are not addressed in this standard. These relays include, but are not limited to, a relay used for arc flash protection, feeder protection relays, breaker failure, and relays whose operation may result in a generator runback. Although the UAT is not directly in the output path from the generator to the Transmission system, it is an essential component for operation of the generating unit or plant.

Refer to the Figures 6 and 7 below for example configurations:

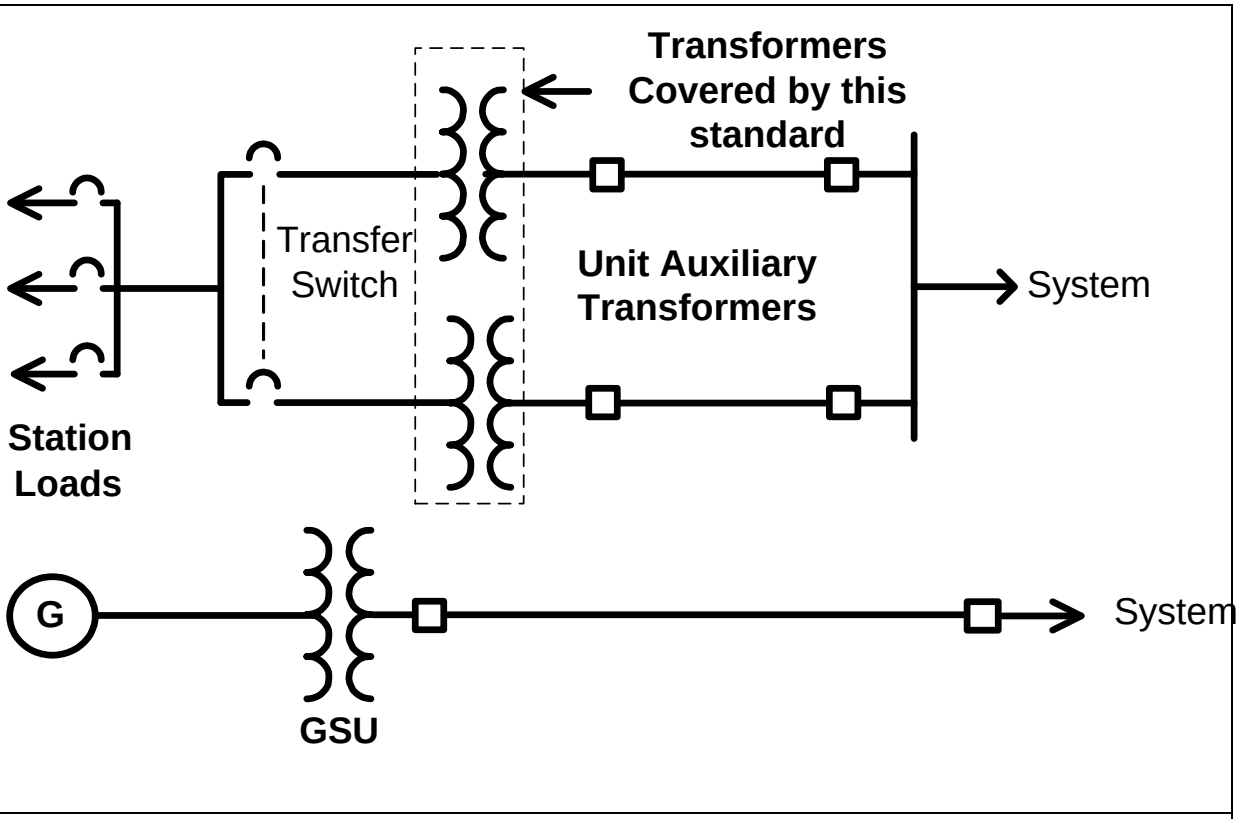


Figure-6 – Auxiliary Power System (independent from generator).

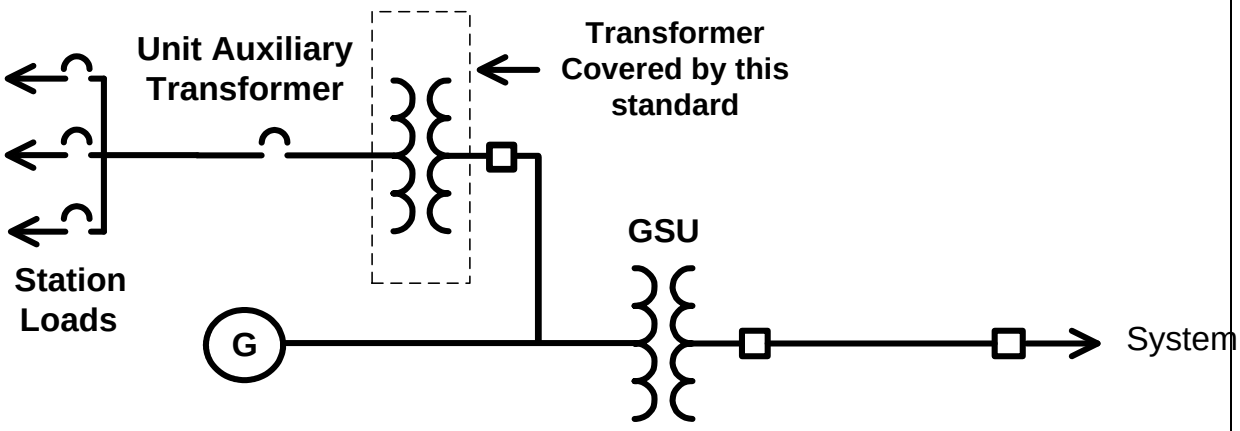


Figure-7 – Typical auxiliary power system for generation units or plants.

The UATs supplying power to the unit or plant electrical auxiliaries are sized to accommodate the maximum expected overall UAT load demand at the highest generator output. Although the transformer nameplate MVA size normally includes capacity for future loads as well as capacity for starting of large induction motors on the original unit or plant design, the nameplate MVA capacity of the transformer may be near full load.

Because of the various design and loading characteristics of UATs, two options (i.e., 13a and 13b) are provided to accommodate an entity's protection philosophy while preventing the UAT transformer phase ~~time~~ overcurrent relays from operating during the dynamic conditions anticipated by this standard.

Options 13a and 13b are based on the transformer bus voltage corresponding to 1.0 per unit nominal voltage on the high-side winding of the UAT.

For Option 13a, the overcurrent element shall be set greater than 150 percent of the calculated current derived from the UAT maximum nameplate MVA rating. This is a simple calculation that approximates the stressed system conditions.

For Option 13b, the overcurrent element shall be set greater than 150 percent of the UAT measured current at the generator maximum gross MW capability reported to the Transmission Planner. This allows for a reduced setting ~~pickup~~ compared to Option 13a and the entity's relay setting philosophy. This is a more involved calculation that approximates the stressed system conditions by allowing the entity to consider the actual load placed on the UAT based on the generator's maximum gross MW capability reported to the Transmission Planner.

The performance of the UAT loads during stressed system conditions (i.e., depressed voltages) is very difficult to determine. Rather than requiring responsible entities to determine the response

of UAT loads to depressed voltage, the technical experts writing the standard elected to increase the margin to 150 percent from that used elsewhere in this standard (e.g., 115 percent) and use a generator bus voltage of 1.0 per unit. A minimum ~~pickup~~setting current based on 150 percent of maximum transformer nameplate MVA rating at 1.0 per unit generator bus voltage will provide adequate transformer protection based on IEEE C37.91 at full load conditions while providing sufficient relay loadability to prevent a trip of the UAT, and subsequent unit trip, due to increased UAT load current during stressed system voltage conditions. Even if the UAT is equipped with an automatic tap changer, the tap changer may not respond quickly enough for the conditions anticipated within this standard, and thus shall not be used to reduce this margin.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (e.g., 21) (Options 14a and 14b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. ~~Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers.~~ These margins are based on guidance found in ~~section 3.1~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays connected on the Elements that connect a GSU transformer to the Transmission system (e.g., at the remote end of the line) that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 14 is used for these relays as well.

Table 1, Options 14a and 14b, establish criteria for phase distance relays directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from ~~operating~~tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 14a reflects a 0.85 per unit ~~Transmission system~~of the line nominal voltage; therefore, establishing that the impedance value used for applying the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant phase distance relays that are directional toward the Transmission system be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit ~~Transmission system~~of the line nominal voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 14b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit ~~nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing.~~line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy

directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 14a, the impedance element ~~is~~shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other ~~application~~applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 14b, the impedance element ~~is~~shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Using simulation is a more involved, more precise setting of the impedance element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Time Overcurrent Relay (e.g., 50 or 51) (Options 15a and 15b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within ~~these~~the Table 1 options ~~differ~~differs from ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays connected on the Elements that connect a GSU transformer to the Transmission system (e.g., at the remote end of the line) that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 15 is used for these relays as well.

Table 1, Options 15a and 15b, establish criteria for phase instantaneous and/or time overcurrent relays to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from ~~operating~~tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 15a reflects a 0.85 per unit ~~Transmission system~~of the line nominal voltage at the relay location; therefore, establishing that the current value used for applying the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant phase

instantaneous and/or time overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit ~~Transmission system~~of the line nominal voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 15b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit ~~nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing.~~line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 15a, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other ~~application~~applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 15b, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Directional ~~Time~~ Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Options 16a and 16b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. ~~Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers.~~ Note that the setting criteria established within ~~these~~the Table 1 options ~~differ~~differs from ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays connected on the

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 16 is used for these relays as well.

Table 1, Options 16a and 16b, establish criteria for phase directional ~~time~~ overcurrent relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from ~~operating~~tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 16a reflects a 0.85 per unit ~~Transmission system~~of the line nominal voltage at the relay location; therefore, establishing that the current value used for applying the interconnection Facilities phase directional ~~time~~ overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit ~~Transmission system~~of the line nominal voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 16b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit ~~nominal voltage on the high side terminals of the GSU transformer prior to field forcing.~~line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 16a, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other ~~application~~applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 16b, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 17)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. ~~Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers.~~ These margins are based on guidance found in ~~section 3.1~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Option 17 establishes criteria for phase distance relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from ~~operating~~tripping during the dynamic conditions anticipated by this standard. Option 17 applies a 1.0 per unit line nominal voltage ~~on~~at the ~~high-side terminals of the GSU transformer~~relay location to calculate the impedance from the maximum aggregate nameplate MVA~~. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant~~.

For Option 17, the impedance element ~~is~~shall be set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase ~~Time~~ Overcurrent Relay (e.g., 50 and 51) (Option 18)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. ~~Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers.~~ Note that the setting criteria established within ~~these~~the Table 1 options ~~differ~~differs from ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 18 establishes criteria for phase ~~time~~ overcurrent relays to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from ~~operating~~tripping during the dynamic conditions anticipated by this standard. Option 18 applies a 1.0 per unit line nominal voltage ~~on~~at the ~~high-side terminals~~location of the ~~GSU transformer~~relay to calculate the current from the maximum aggregate nameplate MVA~~. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant~~.

For Option 18, the overcurrent element ~~is~~shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase Directional ~~Time~~ Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Option 19)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. ~~Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers.~~ Note that the setting criteria established within ~~these~~the Table 1 options ~~differ~~differs from ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 19 establishes criteria for phase directional ~~time~~ overcurrent relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from ~~operating~~tripping during the dynamic conditions anticipated by this standard. Option 19 applies a 1.0 per unit line nominal voltage ~~on~~at the ~~high-side terminals of the GSU transformer~~relay location to calculate the current from the maximum aggregate nameplate MVA~~. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant~~.

For Option 19, the overcurrent element ~~is~~shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Example Calculations

Introduction

Example Calculations.	
Input Descriptions	**Input Values**
Synchronous Generator nameplate (MVA @ rated pf):	$GEN_{Synch_nameplate} = 903\ MVA$
	$pf = 0.85$
Generator rated voltage (Line-to-Line):	$V_{gen_nom} = 22\ kV$
Real Power output in MW as reported to the TP:	$P_{Synch_reported} = 700.0\ MW$
Generator step-up (GSU) transformer rating:	$MVA_{GSU} = 903\ MVA$
GSU transformer reactance (903 MVA base):	$X_{GSU} = 12.14\%$
GSU transformer MVA base:	$MVA_{base} = 767.6\ MVA$
GSU transformer turns ratio:	$GSU_{ratio} = \frac{22\ kV}{346.5\ kV}$
High-side nominal system voltage (Line-to-Line):	$V_{nom} = 345\ kV$
Current transformer (CT) ratio:	$CT_{ratio} = \frac{25000}{5}$
Potential transformer (PT) ratio low-side:	$PT_{ratio} = \frac{200}{1}$
PT ratio high-side:	$PT_{ratio_hv} = \frac{2000}{1}$
Unit auxiliary transformer (UAT) nameplate:	$UAT_{nameplate} = 60\ MVA$
UAT low-side voltage:	$V_{UAT} = 13.8\ kV$
UAT CT ratio:	$CT_{UAT} = \frac{5000}{5}$
CT high voltage ratio:	$CT_{ratio_hv} = \frac{2000}{5}$

Example Calculations.	
Reactive Power output of static reactive device:	$MVAR_{static} = 15\ Mvar$
Reactive Power output of static reactive device generation:	$MVAR_{gen_static} = 5\ Mvar$
Asynchronous generator nameplate (MVA @ rated pf):	$GEN_{Asynch_nameplate} = 40\ MVA$
	$pf = 0.85$
Asynchronous CT ratio:	$CT_{Asynch_ratio} = \frac{5000}{5}$
Asynchronous high voltage CT ratio:	$CT_{Asynch_ratio_hv} = \frac{300}{5}$
CT remote substation bus	$CT_{ratio_remote_bus} = \frac{2000}{5}$

Example Calculations: Option 1a

Option 1a represents the simplest calculation for synchronous generators applying a phase distance relay (e.g., 21) directional toward the Transmission system.

Real Power output (P):

Eq. (1) $$P = GEN_{Synch_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (2) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Option 1a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (3) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (4) $$S = P_{Synch_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (5) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(20.81\ kV)^2}{1347.4\angle -58.7°\ MVA}$$

Example Calculations: Option 1a

$$Z_{pri} = 0.321\angle 58.7° \, \Omega$$

Secondary impedance (Z_{sec}):

Eq. (6) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.321\angle 58.7° \, \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.321\angle 58.7° \, \Omega \times 25$$

$$Z_{sec} = 8.035\angle 58.7° \, \Omega$$

To satisfy the 115% margin in Option 1a:

Eq. (7) $$Z_{\text{sec}\,limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\text{sec}\,limit} = \frac{8.035\angle 58.7° \, \Omega}{1.15}$$

$$Z_{\text{sec}\,limit} = 6.9873\angle 58.7° \, \Omega$$

$$\theta_{transient\ load\ angle} = 58.7°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at ~~85°,~~85°, then the maximum allowable impedance reach is:

Eq. (8) $$Z_{max} < \frac{|Z_{\text{sec}\,limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{6.9873 \, \Omega}{\cos(85.0° - 58.7°)}$$

$$Z_{max} < \frac{6.9873 \, \Omega}{0.896}$$

$$Z_{max} < 7.793\angle 85.0° \, \Omega$$

Example Calculations: Options 1b and 7b

Option 1b represents a more complex, more precise calculation for synchronous generators applying a phase distance relay (e.g., 21) directional toward the Transmission system. This option requires calculating low-side voltage taking into account voltage drop across the GSU transformer. Similarly these calculations may be applied to Option 7b for GSU transformers applying a phase distance relay (e.g., 21) directional toward the Transmission system.

Real Power output (P):

Eq. (9) $$P = GEN_{Synch_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (10) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on a 767.6 MVA base (MVA_{base}):

Real Power output (P):

Eq. (11) $$P_{pu} = \frac{P_{Synch_reported}}{MVA_{base}}$$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (12) $$Q_{pu} = \frac{Q}{MVA_{base}}$$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Example Calculations: Options 1b and 7b

Transformer impedance (X_{pu}):

Eq. (13) $$X_{pu} = X_{GSU(old)} \times \left(\frac{MVA_{base}}{MVA_{GSU}}\right)$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Estimate initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (14) $$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times [V_{high-side}])}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.7°$$

Eq. (15)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Example Calculations: Options 1b and 7b

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (16) $$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times |V_{high-side}|)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (17)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (18) $$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Apparent power (S):

Eq. (19) $$S = P_{Synch_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Example Calculations: Options 1b and 7b

Primary impedance (Z_{pri}):

Eq. (20) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(21.90\ kV)^2}{1347.4\angle -58.7°\ MVA}$$

$$Z_{pri} = 0.356\angle 58.7°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (21) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.356\angle 58.7°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.356\angle 58.7°\ \Omega \times 25$$

$$Z_{sec} = 8.900\angle 58.7°\ \Omega$$

To satisfy the 115% margin in Options 1b and 7b:

Eq. (22) $$Z_{\text{sec}\,limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\text{sec}\,limit} = \frac{8.900\angle 58.7°\ \Omega}{1.15}$$

$$Z_{\text{sec}\,limit} = 7.74\angle 58.7°\ \Omega$$

$$\theta_{transient\ load\ angle} = 58.7°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at ~~85°~~85°, then the maximum allowable impedance reach is:

Eq. (23) $$Z_{max} < \frac{|Z_{\text{sec}\,limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{~~7.74\ \Omega~~}{~~\cos(85.0° - 58.7°)~~} \frac{7.74\ \Omega}{\cos(85.0° - 58.7°)}$$

Example Calculations: Options 1b and 7b

$$Z_{max} < \frac{7.74\ \Omega}{0.8965}$$

$$Z_{max} < 8.633 \angle 85.0° \ \Omega$$

Example Calculations: Options 1c and 7c

Option 1c represents a more involved, more precise setting of the impedance element. This option requires determining maximum generator Reactive Power output during field-forcing and the corresponding generator bus voltage. Once these values are determined, the remainder of the calculation is the same as Options 1a and 1b.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.

~~The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.~~

In this simulation the following values are derived:

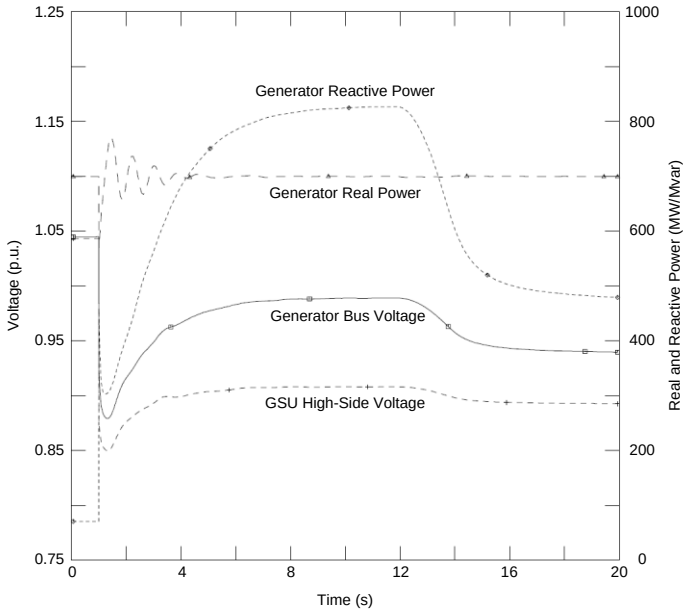
$$Q = 827.4\ Mvar$$

$$~~V_{bus}~~V_{bus_simulated} = 0.989 \times V_{gen_nom} = 21.76\ k\text{V}$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{Synch_reported} = 700.0\ MW$$

Example Calculations: Options 1c and 7c



Apparent power (S):

Eq. (24) $$S = P_{Synch_reported} + jQ$$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (25) $$Z_{pri} = \frac{\cancel{V_{bus}^2}}{\cancel{S^*}} \frac{V_{bus_simulated}^2}{S^*}$$

$$Z_{pri} = \frac{(21.76\ kV)^2}{1083.8\angle -49.8°\ MVA}$$

$$Z_{pri} = 0.437\angle 49.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (26) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.437\angle 49.8°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

Example Calculations: Options 1c and 7c

$$Z_{sec} = 0.437\angle 49.8° \, \Omega \times 25$$

$$Z_{sec} = 10.92\angle 49.8° \, \Omega$$

To satisfy the 115% margin in the requirement in Options 1c and 7c:

Eq. (27) $$Z_{\text{sec}\,limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\text{sec}\,limit} = \frac{10.92\angle 49.8° \, \Omega}{1.15}$$

$$Z_{\text{sec}\,limit} = 9.50\angle 49.8° \, \Omega$$

$$\theta_{transient\ load\ angle} = 49.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at ~~85°~~85°, then the maximum allowable impedance reach is:

Eq. (28) $$Z_{max} < \frac{|Z_{\text{sec}\,limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{\text{~~9.50 Ω~~}}{\text{~~cos(85.0° − 49.8°)~~}} \frac{9.50\ \Omega}{\cos(85.0° - 49.8°)}$$

$$Z_{max} < \frac{9.50\ \Omega}{0.8171}$$

$$Z_{max} < \ 11.63\angle 85.0° \, \Omega$$

Example Calculations: Option 2a

Option 2a represents the simplest calculation for synchronous generators applying a phase ~~time~~ overcurrent (e.g., 50, 51, or 51V-R) ~~voltage restrained~~ relay:

Real Power output (P):

Eq. (29) $$P = \ GEN_{Synch_nameplate} \times pf$$

$$P = 903\ MVA \ \times 0.85$$

$$P = 767.6\ MW$$

Example Calculations: Option 2a

Reactive Power output (Q):

Eq. (30) $Q = 150\% \times P$

$Q = 1.50 \times 767.6\ MW$

$Q = 1151.3\ Mvar$

Option 2a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (31) $V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$

$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$

$V_{gen} = 20.81\ kV$

Apparent power (S):

Eq. (32) $S = P_{Synch_reported} + jQ$

$S = 700.0\ MW + j1151.3\ Mvar$

$S = 1347.4 \angle 58.7°\ MVA$

Primary current (I_{pri}):

Eq. (33) $I_{pri} = \frac{S}{\sqrt{3} \times V_{gen}}$

$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 20.81\ kV}$

$I_{pri} = 37383\ A$

Secondary current (I_{sec}):

Eq. (34) $I_{sec} = \frac{I_{pri}}{CT_{ratio}}$

$I_{sec} = \frac{37383\ A}{\frac{25000}{5}}$

Example Calculations: Option 2a

$$I_{sec} = 7.477\ A$$

To satisfy the 115% margin in Option 2a:

Eq. (35) $$I_{\text{sec}\,limit} > I_{sec} \times 115\%$$

$$I_{\text{sec}\,limit} > 7.477\ A \times 1.15$$

$$I_{\text{sec}\,limit} > 8.598\ A$$

Example Calculations: Option 2b

Option 2b represents a more complex calculation for synchronous generators applying a phase ~~time~~ overcurrent (e.g., 50, 51, or 51V-R) ~~voltage restrained~~ relay:

Real Power output (P):

Eq. (36) $$P = GEN_{Synch_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (37) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base (MVA_{base}).

Real Power output (P):

Eq. (38) $$P_{pu} = \frac{P_{Synch_reported}}{MVA_{base}}$$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Example Calculations: Option 2b

Reactive Power output (Q):

Eq. (39) $$Q_{pu} = \frac{Q}{MVA_{base}}$$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Transformer impedance:

Eq. (40) $$X_{pu} = X_{GSU(old)} \times \frac{MVA_{base}}{MVA_{GSU}}$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Estimate initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (41) $$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times [V_{high-side}])}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.7°$$

Eq. (42)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

Example Calculations: Option 2b

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (43) $$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times [V_{high-side}])}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (44)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (45) $$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Example Calculations: Option 2b

Apparent power (S):

Eq. (46) $S = P_{Synch_reported} + jQ$

$S = 700.0\ MW + j1151.3\ Mvar$

$S = 1347.4 \angle 58.7°\ MVA$

Primary current (I_{pri}):

Eq. (47) $I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$

$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 21.90\ kV}$

$I_{pri} = 35553\ A$

Secondary current (I_{sec}):

Eq. (48) $I_{sec} = \frac{I_{pri}}{CT_{ratio}}$

$I_{sec} = \frac{35553\ A}{\frac{25000}{5}}$

$I_{sec} = 7.111\ A$

To satisfy the 115% margin in Option 2b:

Eq. (49) $I_{\mathrm{sec}\,limit} > I_{sec} \times 115\%$

$I_{\mathrm{sec}\,limit} > 7.111\ A \times 1.15$

$I_{\mathrm{sec}\,limit} > 8.178\ A$

Example Calculations: Option 2c

Option 2c represents a more involved, more precise setting of the overcurrent element for the phase ~~time~~ overcurrent (e.g., 50, 51, or 51V-R) ~~voltage restrained~~ relay. This option requires determining maximum generator Reactive Power output during field-forcing and the corresponding generator bus voltage. Once these values are determined, the remainder of the calculation is the same as Options 2a and 2b.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a voltage-restrained phase overcurrent relay.

~~The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a voltage-restrained phase overcurrent relay.~~

In this simulation the following values are derived:

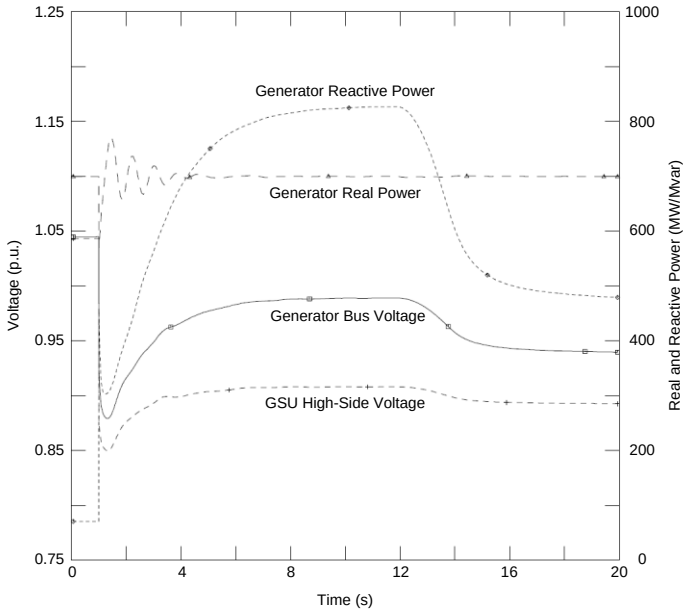
$$Q = 827.4\ Mvar$$

$$~~V_{bus}~~V_{bus_simulated} = 0.989 \times V_{gen_nom} = 21.76\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{Synch_reported} = 700.0\ MW$$

Example Calculations: Option 2c



Apparent power (S):

Eq. (50) $S = P_{Synch_reported} + jQ$

$S = 700.0\ MW + j827.4\ Mvar$

$S = 1083.8 \angle 49.8°\ MVA$

Primary current (I_{pri}):

Eq. (51) $I_{pri} = \frac{~~S~~}{~~\sqrt{3} \times V_{bus}~~} \frac{S}{\sqrt{3} \times V_{bus_simulated}}$

$I_{pri} = \frac{1083.8\ MVA}{1.73 \times 21.76\ kV}$

$I_{pri} = 28790\ A$

Secondary current (I_{sec}):

Eq. (52) $I_{sec} = \frac{I_{pri}}{CT_{ratio}}$

$I_{sec} = \frac{28790\ A}{\frac{25000}{5}}$

Example Calculations: Option 2c

$$I_{sec} = 5.758\ A$$

To satisfy the 115% margin in Option 2c:

Eq. (53) $$I_{\text{sec}\,limit} > I_{sec} \times 115\%$$

$$I_{\text{sec}\,limit} > 5.758\ A \times 1.15$$

$$I_{\text{sec}\,limit} > 6.622\ A$$

Example Calculations: Options 3 and 6

Option 3 represents the only calculation for synchronous generators applying a phase time overcurrent (e.g., 51V-C)~~ voltage controlled~~ relay (Enabled to operate as a function of voltage). Similarly, Option 6 uses the same calculation for asynchronous generators.

Options 3 and 6, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (54) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

The voltage setting shall be set less than 75% of the generator bus voltage:

Eq. (55) $$V_{setting} < V_{gen} \times 75\%$$

$$V_{setting} < 21.9\ kV\ \times 0.75$$

$$V_{setting} < 16.429\ kV$$

Example Calculations: Option 4

This represents the calculation for an asynchronous generator (including inverter-based installations) applying a phase distance relay (e.g., 21)— directional toward the Transmission system.

Example Calculations: Option 4

Real Power output (P):

Eq. (56) $$P = GEN_{Asych_nameplate} \times pf$$

$$P = 40\ MVA \times 0.85$$

$$P = 34.0\ MW$$

Reactive Power output (Q):

Eq. (57) $$Q = GEN_{Async_nameplate} \times \sin(\cos^{-1}(pf))$$

$$Q = 40\ MVA \times \sin(\cos^{-1}(0.85))$$

$$Q = 21.1\ Mvar$$

Option 4, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (58) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (59) $$S = P + jQ$$

$$S = 34.0\ MW + j21.1\ Mvar$$

$$S = 40.0 \angle 31.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (60) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(21.9\ kV)^2}{40.0 \angle -31.8°\ MVA}$$

$$Z_{pri} = 11.99 \angle 31.8°\ \Omega$$

Example Calculations: Option 4

Secondary impedance (Z_{sec}):

Eq. (61) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch_ratio}}{PT_{ratio}}$$

$$Z_{sec} = 11.99 \angle 31.8° \, \Omega \times \frac{\frac{5000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 11.99 \angle 31.8° \, \Omega \times 5$$

$$Z_{sec} = 59.95 \angle 31.8° \, \Omega$$

To satisfy the 130% margin in Option 4:

Eq. (62) $$Z_{\text{sec}\,limit} = \frac{Z_{sec}}{130\%}$$

$$Z_{\text{sec}\,limit} = \frac{59.95 \angle 31.8° \, \Omega}{1.30}$$

$$Z_{\text{sec}\,limit} = 46.12 \angle 31.8° \, \Omega$$

$$\theta_{transient\ load\ angle} = 31.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at ~~85°~~,85°, then the maximum allowable impedance reach is:

Eq. (63) $$Z_{max} < \frac{|Z_{\text{sec}\,limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{46.12 \, \Omega}{\cos(85.0° - 31.8°)}$$

$$Z_{max} < \frac{46.12 \, \Omega}{0.599}$$

$$Z_{max} < 77.0 \angle 85.0° \, \Omega$$

Example Calculations: Option ~~5~~5a

This represents the calculation for three asynchronous generators applying a phase ~~time~~ overcurrent (e.g., 50, 51, or 51V-R) ~~– voltage-restrained~~ relay. In this application it was assumed that 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (64) $$P = 3 \times GEN_{Asynch_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (65) $$Q = MVAR_{static} + MVAR_{gen_static} + \left(3 \times GEN_{Asynch_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Option ~~5~~5a, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (66) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (67) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (68) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

Example Calculations: Option ~~5~~5a

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473\angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (69) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch_ratio}}$$

$$I_{sec} = \frac{3473\angle -39.2°\ A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle -39.2°\ A$$

To satisfy the 130% margin in Option ~~5~~5a:

Eq. (70) $$I_{\text{sec}\,limit} > I_{sec} \times 130\%$$

$$I_{\text{sec}\,limit} > 3.473\angle -39.2°\ A \times 1.30$$

$$I_{\text{sec}\,limit} > 4.52\angle -39.2°\ A$$

Example Calculations: ~~Options 7a and 10~~Option 5b

~~This~~Similarly to Option 5a, this example represents the calculation for ~~a mixture of~~three asynchronous ~~(i.e., Option 10) and synchronous (i.e., Option 7a) generation (including inverter-based installations)~~generators applying a phase ~~distance~~overcurrent (e.g., 50, 51, or 51V-R) relay ~~(21) – directional toward the Transmission system.~~. In this application it was assumed that 20 Mvar of total static compensation was added.

~~**Synchronous Generation (Option 7a)**~~

Real Power output (~~P_{sync}~~):P):

Eq. (71) ~~$P_{Synch} = GEN_{Synch_nameplate} \times pf$~~$P = 3 \times GEN_{Asynch_nameplate} \times pf$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Example Calculations: ~~Options 7a and 10~~Option 5b

Reactive Power output (Q):

Eq. (72) $$Q = MVAR_{static} + MVAR_{gen_static} + \left(3 \times GEN_{Asynch_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Option 5b, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (73) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (74) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (75) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473\angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (76) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch_ratio}}$$

$$I_{sec} = \frac{3473\angle -39.2°\ A}{\frac{5000}{5}}$$

Example Calculations: ~~Options 7a and 10~~Option 5b

$$I_{sec} = 3.473\angle -39.2° \; A$$

To satisfy Option 5b, the overcurrent element shall not infringe upon the resource capability (including the Mvar output of the resource and any static or dynamic reactive power devices) with worst case documented tolerances applied between the maximum resource capability and the overcurrent element (see Figure A).

Example Calculations: Options 7a and 10

These examples represent the calculation for a mixture of asynchronous (i.e., Option 10) and synchronous (i.e., Option 7a) generation (including inverter-based installations) applying a phase distance relay (e.g., 21) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Synchronous Generation (Option 7a)

Real Power output (P_{sync}):

Eq. (77) $$P_{Synch} = GEN_{Synch_nameplate} \times pf$$

$$P_{Synch} = 903 \; MVA \times 0.85$$

$$P_{Synch} = 767.6 \; MW$$

Reactive Power output (Q_{synch}):

Eq. (~~72~~78) $$Q_{Synch} = 150\% \times P_{Synch}$$

$$Q_{Synch} = 1.50 \times 767.6 \; MW$$

$$Q_{Synch} = 1151.3 \; MW$$

Apparent power (S_{Synch}):

Eq. (~~73~~79) $$S_{Synch} = P_{Synch_reported} + jQ_{Synch}$$

$$S_{Synch} = 700.0 \; MW + j1151.3 \; Mvar$$

Example Calculations: Options 7a and 10

Asynchronous Generation (Option 10)

~~Real Power output (P_{Asynch}):~~

Real Power output (P_{Asynch}):

Eq. (~~74~~80) $P_{Asynch} = 3 \times GEN_{Asynch_nameplate} \times pf$

$$P_{Asynch} = 3 \times 40\ MVA \times 0.85$$

$$P_{Asynch} = 102.0\ MW$$

Reactive Power output (Q_{Asynch}):

Eq. (~~75~~81) $Q_{Asynch} = MVAR_{static} + MVAR_{gen_static} + \left(3 \times GEN_{Asynch_nameplate} \times \sin(\cos^{-1}(pf))\right)$

$$Q_{Asynch} = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2\ Mvar$$

Apparent power (S_{Asynch}):

Eq. (~~76~~82) $S_{Asynch} = P_{Asynch} + jQ_{Asynch}$

$$S_{Asynch} = 102.0\ MW + j83.2\ Mvar$$

Options 7a and 10, Table 1 – Bus Voltage, Option 7a specifies 0.95 per unit of the high-side nominal voltage for the generator bus voltage and Option 10 specifies 1.0 per unit of the high-side nominal voltage for generator bus voltage. Due to the presence of the synchronous generator, the 0.95 per unit bus voltage will be used as (V_{gen}) as it results in the most conservative voltage:

Eq. (~~77~~83) $V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S) accounted for 115% margin requirement for a synchronous generator and 130% margin requirement for an asynchronous generator:

Eq. (~~78~~84) $S = 115\% \times \left(P_{Synch_reported} + jQ_{Synch}\right) + 130\% \times (P_{Asynch} + jQ_{Asynch})$

$$S = 1.15 \times (700.0\ MW + j1151.3\ Mvar) + 1.30 \times (102.0\ MW + j83.2\ Mvar)$$

Example Calculations: Options 7a and 10

$$S = 1711.8 \angle 56.8° \, MVA$$

Primary impedance (Z_{pri}):

Eq. (~~79~~85) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(20.81 \, kV)^2}{1711.8 \angle -56.8° \, MVA}$$

$$Z_{pri} = 0.2527 \angle 56.8° \, \Omega$$

Secondary impedance (Z_{sec}):

Eq. (~~80~~86) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.2527 \angle 56.8° \, \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.2527 \angle 56.8° \, \Omega \times 25$$

$$Z_{sec} = 6.32 \angle 56.8° \, \Omega$$

No additional margin is needed~~; therefore, the margin is 100%~~ because the synchronous apparent power has been multiplied by 1.15 (115%) and the asynchronous apparent power has been multiplied by 1.30 (130%) in Equation ~~85~~84 to satisfy the margin requirements in Options 7a and 10~~:~~.

Eq. (~~81~~87) $$Z_{\text{sec}\,limit} = \frac{Z_{sec}}{100\%}$$

$$Z_{\text{sec}\,limit} = \frac{6.32 \angle 56.8° \, \Omega}{1.00}$$

$$Z_{\text{sec}\,limit} = 6.32 \angle 56.8° \, \Omega$$

$$\theta_{transient\ load\ angle} = 56.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at ~~85°,~~85°, then the maximum allowable impedance reach is:

Eq. (~~82~~88) $$Z_{max} < \frac{|Z_{\text{sec}\,limit}|}{\cos\left(\theta_{MTA} - \theta_{transient\ load\ angle}\right)}$$

Example Calculations: Options 7a and 10

$$Z_{max} < \frac{6.32\ \Omega}{\cos(85.0° - 56.8°)}$$

$$Z_{max} < \frac{6.32\ \Omega}{0.881}$$

$$Z_{max} < 7.17 \angle 85.0°\ \Omega$$

Example Calculations: Options 8a and 9a

Options 8a and 9a represents the simplest calculation for synchronous generators applying a phase ~~time~~ overcurrent (e.g., 50, 51, or 67) relay. The following uses the $GEN_{Synch_nameplate}$ value to represent an "aggregate" value to illustrate the option:

Real Power output (P):

Eq. (~~83~~89) $P = GEN_{Synch_nameplate} \times pf$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (~~84~~90) $Q = 150\% \times P$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Options 8a and 9a, Table 1 – Bus Voltage, calls for a generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer generator bus voltage (V_{gen}):

Eq. (~~85~~91) $V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Example Calculations: Options 8a and 9a

Apparent power (S):

Eq. (~~86~~92) $S = P_{Synch_reported} + jQ$

$S = 700.0\ MW + j1151.3\ Mvar$

$S = 1347.4 \angle 58.7°\ MVA$

Primary current (I_{pri}):

Eq. (~~87~~93) $I_{pri} = \frac{S}{\sqrt{3} \times V_{gen}}$

$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 20.81\ kV}$

$I_{pri} = 37383\ A$

Secondary current (I_{sec}):

Eq. (~~88~~94) $I_{sec} = \frac{I_{pri}}{CT_{ratio}}$

$I_{sec} = \frac{37383\ A}{\frac{25000}{5}}$

$I_{sec} = 7.477\ A$

To satisfy the 115% margin in Options 8a and 9a:

Eq. (~~89~~95) $I_{\text{sec}\,limit} > I_{sec} \times 115\%$

$I_{\text{sec}\,limit} > 7.477\ A \times 1.15$

$I_{\text{sec}\,limit} > 8.598\ A$

Example Calculations: Options 8b and 9b

Options 8b and 9b represents a more ~~complex~~precise calculation for synchronous generators applying a phase ~~time~~ overcurrent (e.g., 50, 51, or 67) relay. The following uses the $GEN_{Synch_nameplate}$ value to represent an “aggregate” value to illustrate the option:

Example Calculations: Options 8b and 9b

Real Power output (P):

Eq. (~~90~~96) $P = GEN_{Synch_nameplate} \times pf$

$P = 903\ MVA \times 0.85$

$P = 767.6\ MW$

Reactive Power output (Q):

Eq. (~~91~~97) $Q = 150\% \times P$

$Q = 1.50 \times 767.6\ MW$

$Q = 1151.3\ Mvar$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base (GSU Transformer MVA_{base}).

Real Power output (P):

Eq. (~~92~~98) $P_{pu} = \frac{P_{Synch_reported}}{MVA_{base}}$

$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$

$P_{pu} = 0.91\ p.u.$

Reactive Power output (Q):

Eq. (~~93~~99) $Q_{pu} = \frac{Q}{MVA_{base}}$

$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$

$Q_{pu} = 1.5\ p.u.$

Transformer impedance:

Eq. (~~94~~100) $X_{pu} = X_{GSU(old)} \times \frac{MVA_{base}}{MVA_{GSU}}$

Example Calculations: Options 8b and 9b

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Estimate initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (~~95~~101)
$$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times \lceil V_{high-side} \rceil\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

Eq. (102)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (~~97~~103)
$$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times \lceil V_{high-side} \rceil\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Example Calculations: Options 8b and 9b

Eq. (104)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (~~99~~105)
$$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Apparent power (S):

Eq. (~~100~~106)
$$S = P_{Synch_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4 \angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (~~101~~107)
$$I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 21.90\ kV}$$

$$I_{pri} = 35553\ A$$

Example Calculations: Options 8b and 9b

Secondary current (I_{sec}):

Eq. (~~102~~108)
$$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{35553\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.111\ A$$

To satisfy the 115% margin in Options 8b and 9b:

Eq. (~~103~~109)
$$I_{\text{sec}\,limit} > I_{sec} \times 115\%$$

$$I_{\text{sec}\,limit} > 7.111\ A \times 1.15$$

$$I_{\text{sec}\,limit} > 8.178\ A$$

Example Calculations: Options 8a, 9a, 11, and 12

This example represents the calculation for a mixture of asynchronous and synchronous generators applying a phase ~~time~~ overcurrent (e.g., 50, 51, or 67) relays. In this application it was assumed 20 Mvar of total static compensation was added. The current transformers (CT) are located on the low-side of the GSU transformer.

Synchronous Generation (Options 8a and 9a)

~~Real Power output (P_{Synch}):~~

Real Power output (P_{Synch}):

Eq. (~~104~~110)
$$P_{Synch} = GEN_{Synch_nameplate} \times pf$$

$$P_{Synch} = 903\ MVA \times .85$$

$$P_{Synch} = 767.6\ MW$$

Example Calculations: Options 8a, 9a, 11, and 12

Reactive Power output (Q_{Synch}):

Eq. (~~105~~111) $$Q_{Synch} = 150\% \times P_{Synch}$$

$$Q_{Synch} = 1.50 \times 767.6\ MW$$

$$Q_{Synch} = 1151.3\ Mvar$$

Apparent power (S_{Synch}):

Eq. (~~106~~112) $$S_{Synch} = P_{Synch_reported} + jQ_{Synch}$$

$$S_{Synch} = 700.0\ MW + j1151.3\ Mvar$$

$$S_{Synch} = 1347.4 \angle 58.7°\ MVA$$

Option 8a, Table 1 – Bus Voltage calls for a 0.95 per unit of the high-side nominal voltage as a basis for generator bus voltage (V_{gen}):

Eq. (~~107~~113) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Primary current ($I_{pri\text{-}sync}$):

Eq. (~~108~~114) $$I_{pri-sync} = \frac{115\% \times S^{*}_{Synch}}{\sqrt{3} \times V_{gen}}$$

$$I_{pri-sync} = \frac{1.15 \times (1347.4 \angle -58.7°\ MVA)}{1.73 \times 20.81\ kV}$$

$$I_{pri-sync} = 43061 \angle -58.7°\ A$$

Example Calculations: Options 8a, 9a, 11, and 12

Asynchronous Generation (Options 11 and 12)

~~Real Power output (P_{Asynch}):~~

Real Power output (P_{Asynch}):

Eq. (~~109~~115)
$$P_{Asynch} = 3 \times GEN_{Asynch_nameplate} \times pf$$

$$P_{Asynch} = 3 \times 40\ MVA \times 0.85$$

$$P_{Asynch} = 102.0\ MW$$

Reactive Power output (Q_{Asynch}):

Eq. (~~110~~116)
$$Q_{Asynch} = MVAR_{static} + MVAR_{gen_static} + GEN_{Asynch_nameplate} \times \sin(\cos^{-1}(pf))$$

$$Q_{Asynch} = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2\ Mvar$$

Option 11, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}), however due to the presence of synchronous generator 0.95 per unit bus voltage will be used:

Eq. (~~111~~117)
$$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S_{Asynch}):

Eq. (~~112~~118)
$$S_{Asynch} = 130\% \times (P_{Asynch} + jQ_{Asynch})$$

$$S_{Asynch} = 1.30 \times (102.0\ MW + j83.2\ Mvar)$$

$$S_{Asynch} = 171.1 \angle 39.2°\ MVA$$

Example Calculations: Options 8a, 9a, 11, and 12

Primary current ($I_{pri\text{-}async}$):

Eq. (~~113~~119)
$$I_{pri-async} = \frac{S_{Asych}}{\sqrt{3} \times V_{gen}}$$

$$I_{pri-async} = \frac{171.1 \angle -39.2° \, MVA}{1.73 \times 20.81 \, kV}$$

$$I_{pri-async} = 4755 \angle -39.2° \, A$$

Secondary current (I_{sec}):

Eq. (~~114~~120)
$$I_{sec} = \frac{I_{pri-sync}}{CT_{ratio}} + \frac{I_{pri-async}}{CT_{ratio}}$$

$$I_{sec} = \frac{43061 \angle -58.7° \, A}{\frac{25000}{5}} + \frac{4755 \angle -39.2° \, A}{\frac{25000}{5}}$$

$$I_{sec} = 9.514 \angle -56.8° \, A$$

No additional margin is needed~~; therefore, the margin is 100%~~ because the synchronous apparent power has been multiplied by 1.15 (115%) in Equation ~~94~~114 and the asynchronous apparent power has been multiplied by 1.30 (130%) in Equation ~~98:~~118.

Eq. (~~115~~121)
$$I_{\text{sec}\,limit} > I_{sec} \times 100\%$$

$$I_{\text{sec}\,limit} > 9.514 \angle -56.8° \, A \times 1.00$$

$$I_{\text{sec}\,limit} > 9.514 \angle -56.8° \, A$$

Example Calculations: Options 8c and 9c

This example uses Option 15b as a simulation example for a synchronous generator applying a phase ~~time~~ overcurrent relay~~.~~ (e.g., 50, 51, or 67). In this application the same synchronous generator is modeled as for Options 1c, 2c, and 7c. The CTs are located on the low-side of the GSU transformer.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer, during field-forcing, is used since this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter

Example Calculations: Options 8c and 9c

reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.

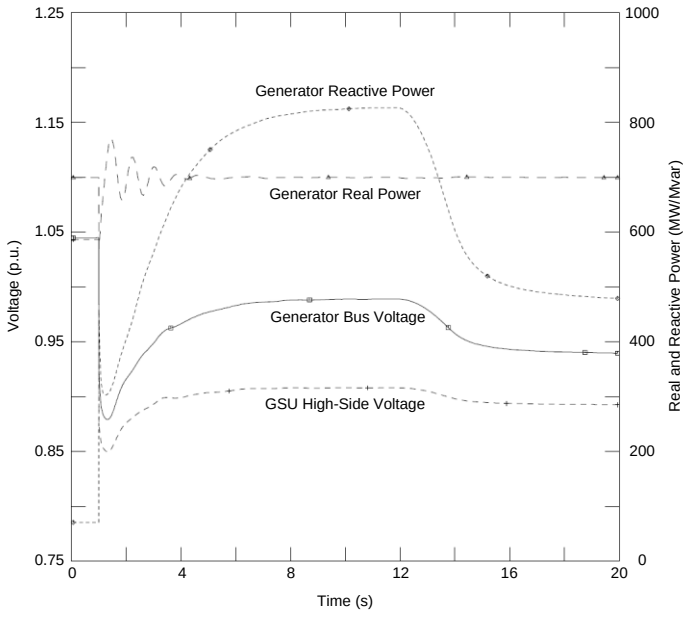
In this simulation the following values are derived:~~The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low side of the GSU transformer during field forcing is used as this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.~~

$$Q = 827.4\ Mvar$$

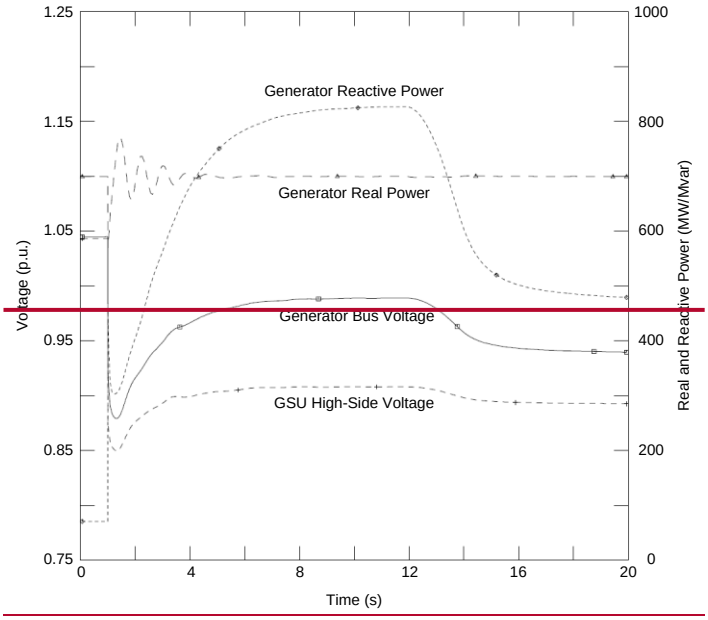
$$~~V_{bus}~~V_{bus_simulated} = 0.989 \times V_{gen} = 21.76\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$



Example Calculations: Options 8c and 9c



Apparent power (S):

Eq. (~~116~~122) $S = P_{Synch_reported} + jQ$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°$$

Primary current (I_{pri}):

Eq. (~~117~~123) $I_{pri} = \frac{~~S~~}{~~\sqrt{3} \times V_{bus}~~} \frac{S}{\sqrt{3} \times V_{bus_simulated}}$

$$I_{pri} = \frac{1083.8\ MVA}{1.73 \times 21.76\ kV}$$

$$I_{pri} = 28790\ A$$

Secondary current (I_{sec}):

Eq. (~~118~~124) $I_{sec} = \frac{I_{pri}}{CT_{ratio}}$

$$I_{sec} = \frac{28790\ A}{\frac{25000}{5}}$$

Example Calculations: Options 8c and 9c

$$I_{sec} = 5.758\ A$$

To satisfy the 115% margin in Options 8c and 9c:

Eq. (~~119~~125) $I_{\text{sec } limit} > I_{sec} \times 115\%$

$$I_{\text{sec } limit} > 5.758\ A \times 1.15$$

$$I_{\text{sec } limit} > 6.622\ A$$

Example Calculations: Option10

This example represents the calculation for three asynchronous generators (including inverter-based installations) applying a phase distance relay (e.g., 21)— directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (~~120~~126) $P = 3 \times GEN_{Asych_nameplate} \times pf$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (~~121~~127) $Q = MVAR_{static} + MVAR_{gen_static} + \left(3 \times GEN_{Asynch_nameplate} \times \sin(\cos^{-1}(pf))\right)$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Option 10, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (~~122~~128) $V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$

Example Calculations: Option10

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (~~123~~129) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (~~124~~130) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(21.9\ kV)^2}{131.6\angle -39.2°\ MVA}$$

$$Z_{pri} = 3.644\ \angle 39.2°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (~~125~~131) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch_ratio}}{PT_{ratio}}$$

$$Z_{sec} = 3.644\ \angle 39.2°\ \Omega \times \frac{\frac{5000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 3.644\ \angle 39.2°\ \Omega \times 5$$

$$Z_{sec} = 18.22\ \angle 39.2°\ \Omega$$

To satisfy the 130% margin in Option 10:

Eq. (~~126~~132) $$Z_{\text{sec}\,limit} = \frac{Z_{sec}}{130\%}$$

$$Z_{\text{sec}\,limit} = \frac{18.22\angle 39.2°\ \Omega}{1.30}$$

Example Calculations: Option10

$$Z_{\sec limit} = 14.02\angle 39.2° \ \Omega$$

$$\theta_{transient\ load\ angle} = 39.2°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at ~~85°~~85°, then the maximum allowable impedance reach is:

Eq. (~~127~~133)
$$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{14.02\ \Omega}{\cos(85.0° - 39.2°)}$$

$$Z_{max} < \frac{14.02\ \Omega}{0.6972}$$

$$Z_{max} < 20.11\angle 85.0° \ \Omega$$

Example Calculations: Options 11 and 12

Option 11 represents the calculation for a GSU transformer applying a phase ~~time~~ overcurrent (e.g., 50 or 51) relay connected to three asynchronous generators. Similarly, these calculations can be applied to Option 12 for a phase directional ~~time~~ overcurrent relay (e.g., 67) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (~~128~~134)
$$P = 3 \times GEN_{Asynch_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (~~129~~135)
$$Q = MVAR_{static} + MVAR_{gen_static} + \left(3 \times GEN_{Asynch_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

Example Calculations: Options 11 and 12

$$Q = 83.2\ Mvar$$

Options 11 and 12, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (~~130~~136)
$$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (~~131~~137)
$$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6 \angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (~~132~~138)
$$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{131.6 \angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473 \angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (~~133~~139)
$$I_{sec} = \frac{I_{pri}}{CT_{Asynch_ratio}}$$

$$I_{sec} = \frac{3473 \angle -39.2°\ A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473 \angle -39.2°\ A$$

Example Calculations: Options 11 and 12

To satisfy the 130% margin in Options 11 and12:

Eq. (~~134~~140)
$$I_{\sec limit} > I_{sec} \times 130\%$$

$$I_{\sec limit} > 3.473\angle -39.2° \; A \times 1.30$$

$$I_{\sec limit} > 4.515\angle -39.2° \; A$$

Example Calculations: Options 13a and 13b

Option 13a for the UAT assumes ~~that~~ the maximum nameplate rating of the winding is utilized for the purposes of the calculations and the appropriate voltage. Similarly, Option 13b uses the measured current while operating at the maximum gross MW capability reported to the Transmission Planner.

Primary current (I_{pri}):

Eq. (~~135~~141)
$$I_{pri} = \frac{UAT_{nameplate}}{\sqrt{3} \times V_{UAT}}$$

$$I_{pri} = \frac{60 \; MVA}{1.73 \times 13.8 \; kV}$$

$$I_{pri} = 2510.2 \; A$$

Secondary current (I_{sec}):

Eq. (~~136~~142)
$$I_{sec} = \frac{I_{pri}}{CT_{UAT}}$$

$$I_{sec} = \frac{2510.2 \; A}{\frac{5000}{5}}$$

$$I_{sec} = 2.51 \text{ A}$$

To satisfy the 150% margin in Options 13a:

Eq. (~~137~~143)
$$I_{\sec limit} > I_{sec} \times 150\%$$

Example Calculations: Options 13a and 13b

$$I_{sec\,limit} > 2.51\ A \times 1.50$$

$$I_{sec\,limit} > 3.77\ A$$

Example Calculations: Option 14a

Option 14a represents the calculation for ~~a synchronous generation~~ Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that connected to synchronous generation. In this example, the Element is ~~applying~~protected by a phase distance (e.g., 21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU transformer.

Real Power output (P):

Eq. (~~138~~144)
$$P = GEN_{Synch_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (~~139~~145)
$$Q = 120\% \times P$$

$$Q = 1.20 \times 767.6\ MW$$

$$Q = 921.1\ Mvar$$

Option 14a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the ~~high side~~line nominal voltage for the GSU transformer voltage (V_{nom}):

Eq. (~~140~~146)
$$V_{bus} = 0.85\ p.u. \times V_{nom}$$

$$V_{gen} = 0.85 \times 345\ kV$$

$$V_{gen} = 293.25\ kV$$

Example Calculations: Option 14a

Apparent power (S):

Eq. (~~141~~147) $$S = P_{Synch_reported} + jQ$$

$$S = 700.0\ MW + j921.1\ Mvar$$

$$S = 1157.0\angle 52.77°\ MVA$$

$$\theta_{transient\ load\ angle} = 52.77°$$

Primary impedance (Z_{pri}):

Eq. (~~142~~148) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(293.25\ kV)^2}{1157.0\angle -52.77°\ MVA}$$

$$Z_{pri} = 74.335\angle 52.77°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (~~143~~149) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio_hv}}{PT_{ratio_hv}}$$

$$Z_{sec} = 74.335\angle 52.77°\ \Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 74.335\angle 52.77°\ \Omega \times 0.2$$

$$Z_{sec} = 14.867\angle 52.77°\ \Omega$$

To satisfy the 115% margin in Option 14a:

Eq. (~~144~~150) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{14.867\angle 52.77°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 12.928\angle 52.77°\ \Omega$$

$$\theta_{transient\ load\ angle} = 52.77°$$

Example Calculations: Option 14a

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at ~~85°~~85°, then the maximum allowable impedance reach is:

Eq. (~~145~~151)
$$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{12.928\ \Omega}{\cos(85.0° - 52.77°)}$$

$$Z_{max} < \frac{12.928\ \Omega}{0.846}$$

$$Z_{max} < 15.283 \angle 85.0°\ \Omega$$

Example Calculations: Option 14b

Option 14b represents the simulation for ~~a synchronous generation~~ Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant ~~that~~connected to synchronous generation. In this example, the Element is ~~applying~~protected by a phase distance (e.g., 21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU transformer.

The Reactive Power flow and high-side bus voltage are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding high-side bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.

~~The Reactive Power flow and high-side bus voltage are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding high-side bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.~~

In this simulation the following values are derived:

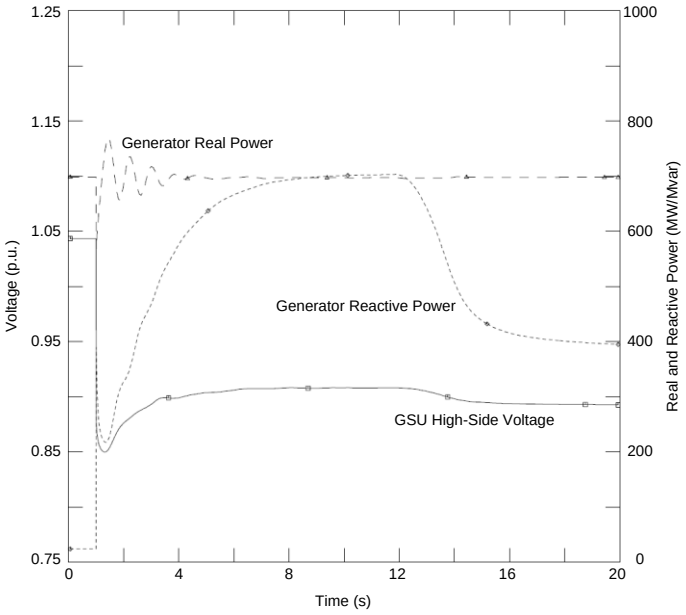
$$Q = 703.6\ Mvar$$

Example Calculations: Option 14b

$$~~V_{bus}~~V_{bus_simulated} = 0.908 \times V_{nom} = 313.3\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$



Apparent power (S):

Eq. (~~146~~152)
$$S = P_{Synch_reported} + jQ$$

$$S = 700.0\ MW + j703.6\ Mvar$$

$$S = 992.5\angle 45.1°\ MVA$$

$$\theta_{transient\ load\ angle} = 45.1°$$

Primary impedance (Z_{pri}):

Eq. (~~147~~153)
$$Z_{pri} = \frac{~~\frac{V_{bus}^2}{S^*}~~}{} \frac{V_{bus_simulated}^2}{S^*}$$

$$Z_{pri} = \frac{(313.3\ kV)^2}{992.5\angle -45.1°\ MVA}$$

Example Calculations: Option 14b

$$Z_{pri} = 98.90\angle 45.1° \, \Omega$$

Secondary impedance (Z_{sec}):

Eq. (~~148~~154)
$$Z_{sec} = Z_{pri} \times \frac{CT_{ratio_hv}}{PT_{ratio_hv}}$$

$$Z_{sec} = 98.90\angle 45.1° \, \Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 98.90\angle 45.1° \, \Omega \times 0.2$$

$$Z_{sec} = 19.78\angle 45.1° \, \Omega$$

To satisfy the 115% margin in Option 14b:

Eq. (~~149~~155)
$$Z_{\text{sec}\,limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\text{sec}\,limit} = \frac{19.78\angle 45.1° \, \Omega}{1.15}$$

$$Z_{\text{sec}\,limit} = 17.20\angle 45.1° \, \Omega$$

$$\theta_{transient\ load\ angle} = 45.1°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at ~~85°~~85°, then the maximum allowable impedance reach is:

Eq. (~~150~~156)
$$Z_{max} < \frac{|Z_{\text{sec}\,limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{17.20 \, \Omega}{\cos(85.0° - 45.1°)}$$

$$Z_{max} < \frac{17.20 \, \Omega}{0.767}$$

$$Z_{max} < 22.42\angle 85.0° \, \Omega$$

Example Calculations: Options 15a and 16a

Options 15a and 16a represent the calculation for ~~a synchronous generation~~ Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~.~~ connected to synchronous generation. Option 15a represents applying a phase time overcurrent relay (e.g., 51) and/or ~~Phase~~phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications —installed on the high-side of the GSU transformer~~,~~ and remote end of the line. Option 16a represents applying a phase directional ~~time overcurrent relay or Phase directional~~instantaneous overcurrent supervisory ~~elements (~~element (e.g., 67) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications —directional toward the Transmission system– installed on the high-side of the GSU and at the remote end of the line and/or a phase time directional overcurrent relay (e.g., 67) directional toward the Transmission system installed on the high-side of the GSU transformer and remote end of the line.

~~This example uses Option 15a as an example, where PTs and CTs are located in the high-side of the GSU transformer.~~Example calculations are provided for the case, where potential transformers (PT) and current transformers (CT) are located at the high-side of the GSU transformer. The 0.85 per unit of the line nominal voltage at the relay location will be at the high-side of the GSU transformer. Example calculations are also provided for the case where PTs and CTs are located at the remote end of the line and the 0.85 per unit of the line nominal voltage will be at the remote bus location.

Calculations at the high-side of the GSU transformer.

Real Power output (P):

Eq. (~~151~~157)
$$P = GEN_{Synch_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (~~152~~158)
$$Q = 120\% \times P$$

$$Q = 1.20 \times 767.6\ MW$$

$$Q = 921.12\ Mvar$$

Example Calculations: Options 15a and 16a

Option 15a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the ~~high side~~line nominal voltage:

Eq. (~~153~~159)
$$V_{bus} = 0.85\ p.u. \times V_{nom}$$

$$V_{bus} = 0.85 \times 345\ kV$$

$$V_{bus} = 293.25\ kV$$

Apparent power (S):

Eq. (~~154~~160)
$$S = P_{Synch_reported} + jQ$$

$$S = 700.0\ MW + j921.12\ Mvar$$

$$S = 1157 \angle 52.8°\ MVA$$

Primary current (I_{pri}):

Eq. (~~155~~161)
$$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1157 \angle -52.8°\ MVA}{1.73 \times 293.25\ kV}$$

$$I_{pri} = 2280.6 \angle -52.8°\ A$$

Secondary current (I_{sec}):

Eq. (~~156~~162)
$$I_{sec} = \frac{I_{pri}}{CT_{ratio_hv}}$$

$$I_{sec} = \frac{2280.6 \angle -52.8°\ A}{\frac{2000}{5}}$$

$$I_{sec} = 5.701 \angle -52.8°\ A$$

To satisfy the 115% margin in Options 15a and ~~15b~~16a:

Eq. (~~157~~163)
$$I_{\mathrm{sec}\,limit} > I_{sec} \times 115\%$$

Example Calculations: Options 15a and 16a

$$I_{sec\,limit} > 5.701 \angle -52.8° \; A \times 1.15$$

$$I_{sec\,limit} > 6.56 \angle -52.8° \; A$$

Calculations at the remote end of the line from the plant.

Real Power output (P):

Eq. (164) $$P = GEN_{Synch_nameplate} \times pf$$

$$P = 903 \; MVA \times 0.85$$

$$P = 767.6 \; MW$$

Reactive Power output (Q):

Eq. (165) $$Q = 120\% \times P$$

$$Q = 1.20 \times 767.6 \; MW$$

$$Q = 921.12 \; Mvar$$

Option 15a and 16a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the line nominal voltage at the relay location, in this example the relay location is at the remote substation bus.

Eq. (166) $$V_{bus_remote_substation} = 0.85 \; p.u. \times V_{nom}$$

$$V_{bus_remote_substation} = 0.85 \times 345 \; kV$$

$$V_{bus_remote_substation} = 293.25 \; kV$$

Apparent power (S):

Eq. (167) $$S = P_{Synch_reported} + jQ$$

$$S = 700.0 \; MW + j921.12 \; Mvar$$

$$S = 1157 \angle 52.8° \; MVA$$

Primary current (I_{pri}):

Eq. (168) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus_remote_substation}}$$

Example Calculations: Options 15a and 16a

$$I_{pri} = \frac{1157\angle -52.8°\ MVA}{1.73 \times 293.25\ kV}$$

$$I_{pri} = 2280.6\angle -52.8°\ A$$

Secondary current (I_{sec}):

Eq. (169) $$I_{sec} = \frac{I_{pri}}{CT_{CT_{ratio_remote_bus}}}$$

$$I_{sec} = \frac{2280.6\angle -52.8°\ A}{\frac{2000}{5}}$$

$$I_{sec} = 5.701 \angle -52.8°\ A$$

To satisfy the 115% margin in Options 15a and 16a:

Eq. (170) $$I_{\text{sec}\,limit} > I_{sec} \times 115\%$$

$$I_{\text{sec}\,limit} > 5.701 \angle -52.8°\ A \times 1.15$$

$$I_{\text{sec}\,limit} > 6.56 \angle -52.8°\ A$$

Example Calculations: Options 15b and 16b

Options 15b and 16b represent the calculation for ~~a synchronous generation~~ Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~.~~ connected to synchronous generation. Option 15b represents applying a phase time overcurrent relay (e.g., 51) and/or ~~Phase~~phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications —installed on the high-side of the GSU transformer~~.~~ and remote end of the line. Option 16b represents applying a phase directional ~~time overcurrent relay or Phase directional~~instantaneous overcurrent supervisory ~~elements (~~element (e.g., 67) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications —directional toward the Transmission system– installed on the high-side of the GSU and at the remote end of the line and/or a phase directional time overcurrent relay (e.g., 67) directional toward the Transmission system installed on the high-side of the GSU and remote end of the line.

~~This example uses Option 15b as a simulation example~~Example calculations are provided for the case, where PTs and CTs are located at the remote end of the line from the plant. The 0.85 per unit of the line nominal voltage is applied at the remote end of the line.

The Reactive Power flow and high-side bus voltage are determined by simulation. The maximum Reactive Power output on the ~~in the~~ high-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding high-side bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.

~~The Reactive Power flow and high-side bus voltage are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding high-side bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.~~

In this simulation the following values are derived:

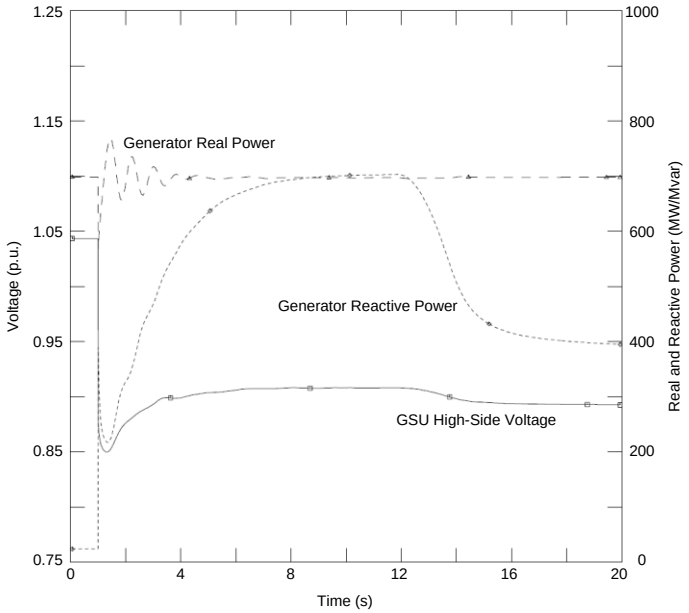
$$Q = 703.6\ Mvar$$

$$~~V_{bus}~~V_{bus_simulated} = 0.908 \times V_{nom} = 313.3\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$

Example Calculations: Options 15b and 16b



Apparent power (S):

Eq. (~~158~~171)
$$S = P_{Synch_reported} + jQ$$

$$S = 700.0\ MW + j703.6\ Mvar$$

$$S = 992.5\angle 45.1°\ MVA$$

Primary current (I_{pri}):

Eq. (~~159~~172)
$$I_{pri} = \frac{\cancel{S^*}}{\cancel{\sqrt{3} \times V_{bus}}} \frac{S^*}{\sqrt{3} \times V_{bus_simulated}}$$

$$I_{pri} = \frac{992.5\angle -45.1°\ MVA}{1.73 \times 313.3\ kV}$$

$$I_{pri} = 1831.2\angle -45.1°\ A$$

Secondary current (I_{sec}):

Eq. (~~160~~173)
$$I_{sec} = \frac{I_{pri}}{CT_{ratio_hv}}$$

Example Calculations: Options 15b and 16b

$$I_{sec} = \frac{1831.2\angle -45.1° \; A}{\frac{2000}{5}}$$

$$I_{sec} = 4.578 \angle -45.1° \; A$$

To satisfy the 115% margin in Options 15b and 16b:

Eq. (~~161~~174)
$$I_{\text{sec}\,limit} > I_{sec} \times 115\%$$

$$I_{\text{sec}\,limit} > 4.578 \angle -45.1° \; A \times 1.15$$

$$I_{\text{sec}\,limit} > 5.265 \angle -45.1° \; A$$

Example Calculations: Option 17

Option 17 represents the calculation for ~~three asynchronous generation~~ Elements that connect a GSU transformer for three asynchronous generators to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that is applying a phase distance relay (e.g., 21)~~–~~ directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (~~162~~175)
$$P_{Asynch} = \; 3 \times GEN_{Asynch_nameplate} \times pf$$

$$P_{Asynch} = 3 \times 40 \; MVA \; \times 0.85$$

$$P_{Asynch} = 102.0 \; MW$$

Reactive Power output (Q):

Eq. (~~163~~176)
$$Q_{Asynch} = MVAR_{static} + MVAR_{gen_static} + \left(3 \times GEN_{Asynch_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q_{Asynch} = 15 \; Mvar + 5 \; Mvar + (3 \times 40 \; MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2 \; Mvar$$

Example Calculations: Option 17

Option 17, Table 1 – Bus Voltage, calls for a 1.0 per unit of the ~~high side~~line nominal voltage for the bus voltage (V_{bus}):

Eq. (~~164~~177)
$$V_{bus} = 1.0\ p.u. \times V_{nom}$$

$$V_{gen} = 1.0 \times 345\ kV$$

$$V_{gen} = 345.0\ kV$$

Apparent power (S):

Eq. (~~165~~178)
$$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (~~166~~179)
$$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(345.0\ kV)^2}{131.6\angle -39.2°\ MVA}$$

$$Z_{pri} = 904.4\angle 39.2°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (~~167~~180)
$$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch_ratio_hv}}{PT_{ratio_hv}}$$

$$Z_{sec} = 904.4\angle 39.2°\ \Omega \times \frac{\frac{300}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 904.4\angle 39.2°\ \Omega \times 0.03$$

$$Z_{sec} = 27.13\angle 39.2°\ \Omega$$

Example Calculations: Option 17

To satisfy the 130% margin in Option 17:

Eq. (~~168~~181)
$$Z_{\sec limit} = \frac{Z_{sec}}{130\%}$$

$$Z_{\sec limit} = \frac{27.13\angle 39.2°\ \Omega}{1.30}$$

$$Z_{\sec limit} = 20.869\angle 39.2°\ \Omega$$

$$\theta_{transient\ load\ angle} = 39.2°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at ~~85°~~85°, and then the maximum allowable impedance reach is:

Eq. (~~169~~182)
$$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{20.869\ \Omega}{\cos(85.0° - 39.2°)}$$

$$Z_{max} < \frac{20.869\ \Omega}{0.697}$$

$$Z_{max} < 29.941\angle 85.0°\ \Omega$$

Example Calculations: Options 18 and 19

Option 18 represents the calculation for ~~three generation~~relays on Elements that connect a GSU transformer for three asynchronous generators to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant ~~that is~~. Option 18 represents applying a phase time overcurrent (e.g., 51) ~~relay connected to three asynchronous generators.~~ and/or phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer and remote end of the line.

Similarly, Option 19 may also be applied here for the phase directional ~~time~~ overcurrent relays (e.g., 67) directional toward the Transmission system for Elements that connect a GSU transformer and remote end of the line to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. In this application it was assumed 20 Mvar of total static compensation was added.

Example Calculations: Options 18 and 19

Real Power output (P):

Eq. (~~170~~183)
$$P = 3 \times GEN_{Asych_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (~~171~~184)
$$Q = MVAR_{static} + MVAR_{gen_static} + \left(3 \times GEN_{Asynch_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Options 18 and 19, Table 1 – Bus Voltage, calls for a 1.0 per unit of the ~~high side~~line nominal voltage (V_{bus}):

Eq. (~~172~~185)
$$V_{nom} = 1.0\ p.u. \times V_{nom}$$

$$V_{bus} = 1.0 \times 345\ kV$$

$$V_{bus} = 345\ kV$$

Apparent power (S):

Eq. (~~173~~186)
$$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (~~174~~187)
$$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 345\ kV}$$

Example Calculations: Options 18 and 19

$$I_{pri} = 220.5 \angle -39.2° A$$

Secondary current (I_{sec}):

Eq. (~~175~~188)
$$I_{sec} = \frac{I_{pri}}{CT_{Asynch_ratio_hv}}$$

$$I_{sec} = \frac{220.5 \angle -39.2° \, A}{\frac{300}{5}}$$

$$I_{sec} = 3.675 \angle -39.2° \, A$$

To satisfy the 130% margin in Options 18 and 19:

Eq. (~~176~~189)
$$I_{\text{sec}\,limit} > I_{sec} \times 130\%$$

$$I_{\text{sec}\,limit} > 3.675 \angle -39.2° \, A \times 1.30$$

$$I_{\text{sec}\,limit} > 4.778 \angle -39.2° \, A$$

End of calculations

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:

Requirement R1 is a risk-based requirement that requires the responsible entity to be aware of each protective relay subject to the standard and applies an appropriate setting based on its calculations or simulation for the conditions established in Attachment 1.

The criteria established in Attachment 1 represent short-duration conditions during which generation Facilities are capable of providing system reactive resources, and for which generation Facilities have been historically recorded to disconnect, causing events to become more severe.

The term, “while maintaining reliable fault protection” in Requirement R1 describes that the responsible entity is to comply with this standard while achieving their desired protection goals. Refer to the Guidelines and Technical Basis, Introduction, for more information.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

The standard drafting team (PRC_025) is posting Draft 1 of PRC-025-2, Generator Relay Loadability for a 45-day formal comment period and initial ballot in the last ten days of the comment period.

Completed Actions	Date
The Standards Committee (SC) authorized the SAR for posting	September 14, 2016
Draft 1 of the Standards Authorization Request (SAR) was posted for a 30-day formal comment period	September 16, 2016 through October 18, 2016
Draft 2 of the SAR was posted for a 15-day informal comment period	March 20, 2017 through April 3, 2017
The SC accepted the SAR and appointed the SAR drafting team as the standard drafting team (SDT)	April 19, 2017

Anticipated Actions	Date
45-day formal comment period with initial ballot	July 2017
45-day formal comment period with additional ballot	September 2017
10-day final ballot	January 2018
Board adoption	February 2018

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):
None.

A. Introduction

1. **Title:** **Generator Relay Loadability**

2. **Number:** **PRC-025-2**

3. **Purpose:** To set load-responsive protective relays associated with generation Facilities at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Generator Owner that applies load-responsive protective relays at the terminals of the Elements listed in 3.2, Facilities.

   4.1.2. Transmission Owner that applies load-responsive protective relays at the terminals of the Elements listed in 3.2, Facilities.

   4.1.3. Distribution Provider that applies load-responsive protective relays at the terminals of the Elements listed in 3.2, Facilities.

   4.2. Facilities: The following Elements associated with Bulk Electric System (BES) generating units and generating plants, including those generating units and generating plants identified as Blackstart Resources in the Transmission Operator's system restoration plan:

   4.2.1. Generating unit(s).

   4.2.2. Generator step-up (i.e., GSU) transformer(s).

   4.2.3. Unit auxiliary transformer(s) (UAT) that supply overall auxiliary power necessary to keep generating unit(s) online.[1]

   4.2.4. Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

   4.2.5. Elements utilized in the aggregation of dispersed power producing resources.

5. **Effective Date:** See Implementation Plan

6. **Background:** After analysis of many of the major disturbances in the last 25 years on the North American interconnected power system, generators have been found to have

[1] These transformers are variably referred to as station power, unit auxiliary transformer(s) (UAT), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Loss of these transformers will result in removing the generator from service. Refer to the PRC-025-2 Guidelines and Technical Basis for more detailed information concerning unit auxiliary transformers.

tripped for conditions that did not apparently pose a direct risk to those generators and associated equipment within the time period where the tripping occurred. This tripping has often been determined to have expanded the scope and/or extended the duration of that disturbance. This was noted to be a serious issue in the August 2003 "blackout" in the northeastern North American continent.[2]

During the recoverable phase of a disturbance, the disturbance may exhibit a "voltage disturbance" behavior pattern, where system voltage may be widely depressed and may fluctuate. In order to support the system during this transient phase of a disturbance, this standard establishes criteria for setting load-responsive protective relays such that individual generators may provide Reactive Power within their dynamic capability during transient time periods to help the system recover from the voltage disturbance. The premature or unnecessary tripping of generators resulting in the removal of dynamic Reactive Power exacerbates the severity of the voltage disturbance, and as a result changes the character of the system disturbance. In addition, the loss of Real Power could initiate or exacerbate a frequency disturbance.

7. Standard Only Definition: None.

B. Requirements and Measures

R1. Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-2 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection. *[Violation Risk Factor: High] [Time Horizon: Long-Term Planning]*

M1. For each load-responsive protective relay, each Generator Owner, Transmission Owner, and Distribution Provider shall have evidence (e.g., summaries of calculations, spreadsheets, simulation reports, or setting sheets) that settings were applied in accordance with PRC-025-2 – Attachment 1: Relay Settings.

C. Compliance

8. Compliance Monitoring Process

8.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

[2] Interim Report: Causes of the August 14th Blackout in the United States and Canada, U.S.-Canada Power System Outage Task Force, November 2003 (http://www.nerc.com/docs/docs/blackout/814BlackoutReport.pdf)

8.2. Evidence Retention

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

The Generator Owner, Transmission Owner, and Distribution Provider shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner, Transmission Owner, and Distribution Provider shall retain evidence of Requirement R1 and Measure M1 for the most recent three calendar years.
- If a Generator Owner, Transmission Owner, or Distribution Provider 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.

8.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

8.4. Additional Compliance Information

None.

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-Term Planning	High	N/A	N/A	N/A	The Generator Owner, Transmission Owner, and Distribution Provider did not apply settings in accordance with *PRC-025-2 – Attachment 1: Relay Settings*, on an applied load-responsive protective relay.

D. Regional Variances

None.

E. Associated Documents

NERC System Protection and Control Subcommittee, "Considerations for Power Plant and Transmission System Protection Coordination," technical reference document, Revision 2. (Date of Publication: July 2015)

IEEE C37.102-2006, "IEEE Guide for AC Generator Protection." (Date of Publication: 2006)

IEEE C37.17-2012, "IEEE Standard for Trip Systems for Low-Voltage (1000 V and below) AC and General Purpose (1500 V and below) DC Power Circuit Breakers." (Date of Publication: September 18, 2012)

IEEE C37.2-2008, "IEEE Standard for Electrical Power System Device Function Numbers, Acronyms, and Contact Designations." (Date of Publication: October 3, 2008)

Version History

Version	Date	Action	Change Tracking
1	August 15, 2013	Adopted by NERC Board of Trustees	New
1	July 17, 2014	FERC order issued approving PRC-025-1	
2	April 19, 2017	SAR accepted by Standards Committee	Revision
2		Adopted by NERC Board of Trustees	
2		FERC order issued approving PRC-025-2	

PRC-025-2 – Attachment 1: Relay Settings

Introduction

This standard does not require the Generator Owner, Transmission Owner, or Distribution Provider to use any of the protective functions listed in Table 1. Each Generator Owner, Transmission Owner, and Distribution Provider that applies load-responsive protective relays on their respective Elements listed in 3.2, Facilities, shall use one of the following Options in Table 1, Relay Loadability Evaluation Criteria ("Table 1"), to set each load-responsive protective relay element according to its application and relay type. The bus voltage is based on the criteria for the various applications listed in Table 1.

Generators

Synchronous generator relay setting criteria values are derived from the unit's maximum gross Real Power capability, in megawatts (MW), as reported to the Transmission Planner, and the unit's Reactive Power capability, in megavoltampere-reactive (Mvar), is determined by calculating the MW value based on the unit's nameplate megavoltampere (MVA) rating at rated power factor. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard as a minimum requirement. The Generator Owner may base settings on a capability that is higher than what is reported to the Transmission Planner.

Asynchronous generator relay setting criteria values (including inverter-based installations) are derived from the site's aggregate maximum complex power capability, in MVA, as reported to the Transmission Planner, including the Mvar output of any static or dynamic reactive power devices. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard as a minimum requirement. The Generator Owner may base settings on a capability that is higher than what is reported to the Transmission Planner.

For applications where synchronous and asynchronous generator types are combined on a generator step-up transformer or on Elements that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads), the setting criteria shall be determined by vector summing the setting criteria of each generator type, and using the bus voltage for the given synchronous generator application and relay type.

Transformers

Calculations using the GSU transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with de-energized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU transformer turns ratio shall be used.

Applications that use more complex topology, such as generators connected to a multiple winding transformer, are not directly addressed by the criteria in Table 1. These topologies can result in complex power flows, and may require simulation to avoid overly conservative

assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

Multiple Lines

Applications that use more complex topology, such as multiple lines that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads) are not directly addressed by the criteria in Table 1. These topologies can result in complex power flows, and it may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

Exclusions

The following protection systems are excluded from the requirements of this standard:

1. Any relay elements that are in service only during start up.
2. Load-responsive protective relay elements that are armed only when the generator is disconnected from the system, (e.g., non-directional overcurrent elements used in conjunction with inadvertent energization schemes, and open breaker flashover schemes).
3. Phase fault detector relay elements employed to supervise other load-responsive phase distance elements (e.g., in order to prevent false operation in the event of a loss of potential) provided the distance element is set in accordance with the criteria outlined in the standard.
4. Protective relay elements that are only enabled when other protection elements fail (e.g., overcurrent elements that are only enabled during loss of potential conditions).
5. Protective relay elements used only for Remedial Action Schemes that are subject to one or more requirements in a NERC or Regional Reliability Standard.
6. Protection systems that detect generator overloads that are designed to coordinate with the generator short time capability by utilizing an extremely inverse characteristic set to operate no faster than 7 seconds at 218% of full load current (e.g., rated armature current), and prevent operation below 115% of full-load current.[3]
7. Protection systems that detect overloads and are designed only to respond in time periods which allow an operator 15 minutes or greater to respond to overload conditions.

Table 1

Table 1 below is structured and formatted to aid the reader with identifying an option for a given load-responsive protective relay.

The first column identifies the application (e.g., synchronous or asynchronous generators, generator step-up transformers, unit auxiliary transformers, Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly

[3] IEEE C37.102-2006, "Guide for AC Generator Protection," Section 4.1.1.2.

from a BES generating unit or generating plant). Dark blue horizontal bars, excluding the header which repeats at the top of each page, demarcate the various applications.

The second column identifies the load-responsive distance or overcurrent protective relay by IEEE device numbers (e.g., 21, 50, 51, 51V-C, 51V-R, or 67) according to the application in the first column. This also includes manufacture protective device trip unit designations for long-time delay, short-time delay, and instantaneous (e.g., L, S, and I). A light blue horizontal bar between the relay types is the demarcation between relay types for a given application. These light blue bars will contain no text, except when the same application continues on the next page of the table with a different relay type.

The third column uses numeric and alphabetic options (i.e., index numbering) to identify the available options for setting load-responsive protective relays according to the application and applied relay type. Another, shorter, light blue bar contains the word “OR,” and reveals to the reader that the relay for that application has one or more options (i.e., “ways”) to determine the bus voltage and setting criteria in the fourth and fifth column, respectively. The bus voltage column and setting criteria columns provide the criteria for determining an appropriate setting. The table is further formatted by shading groups of relays associated with asynchronous generator applications. Synchronous generator applications and the unit auxiliary transformer applications are not shaded. Also, intentional buffers were added to the table such that similar options, as possible, would be paired together on a per page basis. Note that some applications may have an additional pairing that might occur on adjacent pages.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Setting Criteria**
Synchronous generating unit(s), including Elements utilized in the aggregation of dispersed power producing resources	Phase distance relay (e.g., 21) – directional toward the Transmission system	1a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		1b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		1c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[4] Calculations using the generator step-up (GSU) transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with deenergized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU turns ratio shall be used.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Setting Criteria**
Synchronous generating unit(s), including Elements utilized in the aggregation of dispersed power producing resources	Phase overcurrent relay (e.g., 50, 51, or 51V-R – voltage-restrained)	2a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		2b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		2c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner or, and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation
	Phase time overcurrent relay (e.g., 51V-C) – voltage controlled (Enabled to operate as a function of voltage)	3	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage
A different application starts on the next page				

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Setting Criteria**
Asynchronous generating unit(s) (including inverter-based installations), including Elements utilized in the aggregation of dispersed power producing resources	Phase distance relay (e.g., 21) – directional toward the Transmission system	4	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase overcurrent relay (e.g., 50, 51, or 51V-R – voltage-restrained)	5a	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
		OR		
		5b	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall not infringe upon the resource capability (including the Mvar output of the resource and any static or dynamic reactive power devices) with worst case documented tolerances applied between the maximum resource capability and the overcurrent element (see Figure A).
	Phase time overcurrent relay (e.g., 51V-C) – voltage controlled (Enabled to operate as a function of voltage)	6	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage
A different application starts on the next page				

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Setting Criteria**
Generator step-up transformer(s) connected to synchronous generators	Phase distance relay (e.g., 21) – directional toward the Transmission system – installed on generator-side of the GSU transformer[5]	7a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		7b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		7c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[5] If the relay is installed on the high-side of the GSU transformer use Option 14.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Setting Criteria**
Generator step-up transformer(s) connected to synchronous generators	Phase overcurrent relay (e.g., 50 or 51) – installed on generator-side of the GSU transformer[6]	8a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		8b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		8c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[6] If the relay is installed on the high-side of the GSU transformer use Option 15.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Setting Criteria**
Generator step-up transformer(s) connected to synchronous generators	Phase directional overcurrent relay (e.g., 67) – directional toward the Transmission system – installed on generator-side of the GSU transformer[7]	9a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		9b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		9c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
A different application starts on the next page				

[7] If the relay is installed on the high-side of the GSU transformer use Option 16.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Setting Criteria**
Generator step-up transformer(s) connected to asynchronous generators only (including inverter-based installations)	Phase distance relay (e.g., 21) – directional toward the Transmission system – installed on generator-side of the GSU transformer[8]	10	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase overcurrent relay (e.g., 50 or 51) – installed on generator-side of the GSU transformer[9]	11	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer for overcurrent relays installed on the low-side	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase directional overcurrent relay (e.g., 67) – directional toward the Transmission system – installed on generator-side of the GSU transformer[10]	12	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
A different application starts on the next page				

[8] If the relay is installed on the high-side of the GSU transformer use Option 17.
[9] If the relay is installed on the high-side of the GSU transformer use Option 18.
[10] If the relay is installed on the high-side of the GSU transformer use Option 19.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Setting Criteria**
Unit auxiliary transformer(s) (UAT)	Phase overcurrent relay (e.g., 50 or 51) applied at the high-side terminals of the UAT, for which operation of the relay will cause the associated generator to trip.	13a	1.0 per unit of the winding nominal voltage of the unit auxiliary transformer	The overcurrent element shall be set greater than 150% of the calculated current derived from the unit auxiliary transformer maximum nameplate MVA rating
		OR		
		13b	Unit auxiliary transformer bus voltage corresponding to the measured current	The overcurrent element shall be set greater than 150% of the unit auxiliary transformer measured current at the generator maximum gross MW capability reported to the Transmission Planner
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads) – connected to synchronous generators	Phase distance relay (e.g., 21) – directional toward the Transmission system installed on the high-side of the GSU transformer and on the remote end of line[11]	14a	0.85 per unit of the line nominal voltage at the relay location	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		14b	Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[11] If the relay is installed on the generator-side of the GSU transformer use Option 7.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Setting Criteria**
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads) – connected to synchronous generators	Phase instantaneous overcurrent supervisory element (e.g., 50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer and remote end of the line and/or phase time overcurrent relay (e.g., 51) – installed on the high-side of the GSU transformer and remote end of the line[12]	15a	0.85 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		15b	Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[12] If the relay is installed on the generator-side of the GSU transformer use Option 8.

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[4]	Setting Criteria
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant load.) – connected to synchronous generators	Phase directional instantaneous overcurrent supervisory element (e.g., 67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system installed on the high-side of the GSU transformer and remote end of the line and/or phase directional time overcurrent relay (e.g., 67) – directional toward the Transmission system installed on the high-side of the GSU transformer and remote end of the line[13]	16a	0.85 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		16b	Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
A different application starts on the next page				

[13] If the relay is installed on the generator-side of the GSU transformer use Option 9.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Setting Criteria**
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads) – connected to asynchronous generators only (including inverter-based installations)	Phase distance relay (e.g., 21) – directional toward the Transmission system– installed on the high-side of the GSU transformer and on the remote end of line[14]	17	1.0 per unit of the line nominal voltage at the relay location	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	The same application continues on the next page with a different relay type			

[14] If the relay is installed on the generator-side of the GSU transformer use Option 10.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Setting Criteria**
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads) – connected to asynchronous generators only (including inverter-based installations)	Phase instantaneous overcurrent supervisory element (e.g., 50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer and on the remote end of the line and/or Phase time overcurrent relay (e.g., 51) – installed on the high-side of the GSU transformer and on the remote end of the line[15]	18	1.0 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	The same application continues on the next page with a different relay type			

[15] If the relay is installed on the generator-side of the GSU transformer use Option 11.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Setting Criteria**
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads) – connected to asynchronous generators only (including inverter-based installations)	Phase directional instantaneous overcurrent supervisory element (e.g., 67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system installed on the high-side of the GSU transformer and on the remote end of the line and/or Phase directional time overcurrent relay (e.g., 67) – installed on the high-side of the GSU transformer and on the remote end of the line[16]	19	1.0 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
End of Table 1				

[16] If the relay is installed on the generator-side of the GSU transformer use Option 12.

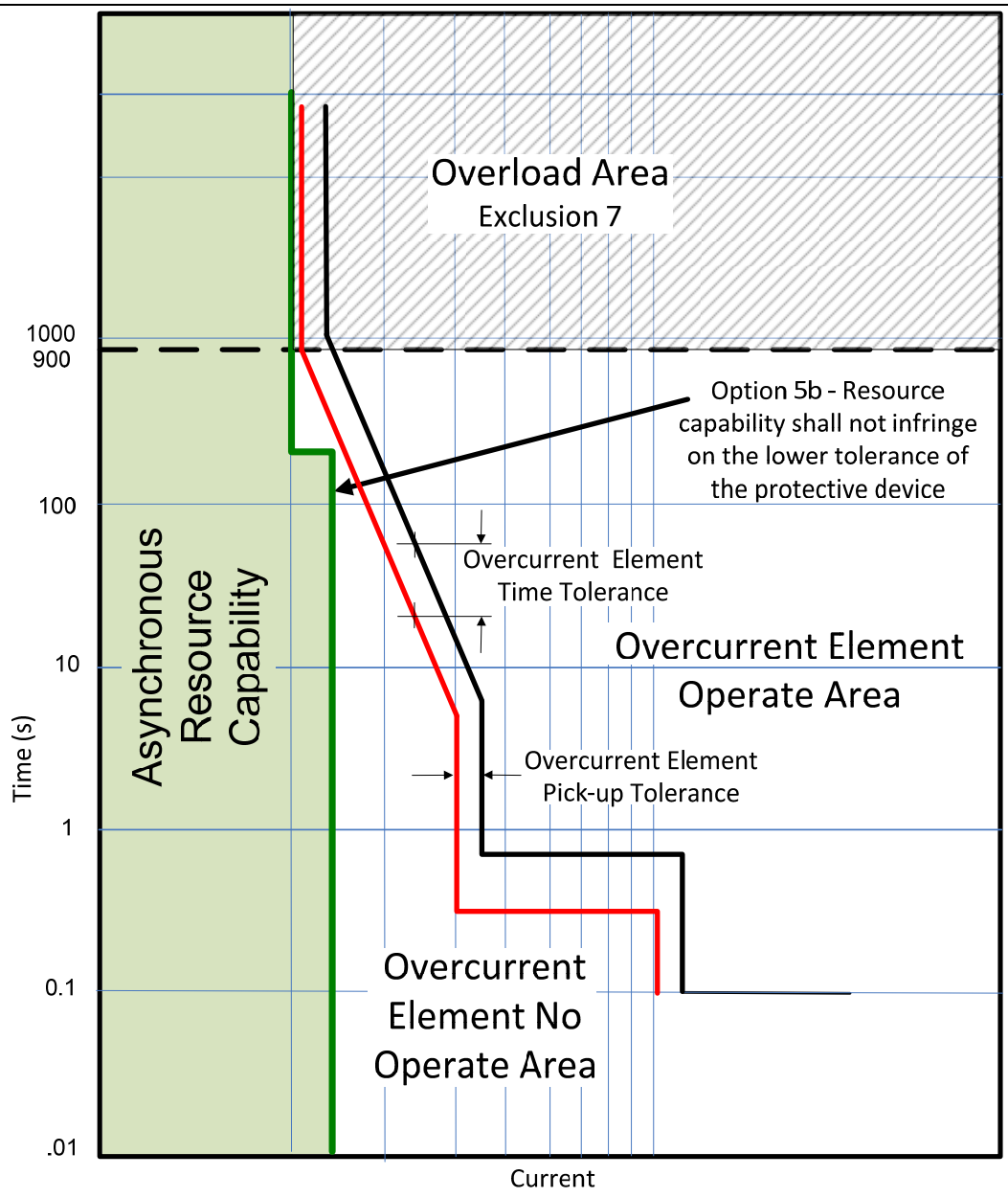


Figure A. This figure is for demonstration of Option 5b and does not mandate a specific type of protective curve or device manufacturer.

PRC-025-2 Guidelines and Technical Basis

Introduction

The document, "Considerations for Power Plant and Transmission System Protection Coordination," published by the NERC System Protection and Control Subcommittee (SPCS) provides extensive general discussion about the protective functions and generator performance addressed within this standard. This document was last revised in July 2015.[17]

The basis for the standard's loadability criteria for relays applied at the generator terminals or low-side of the generator step-up (GSU) transformer is the dynamic generating unit loading values observed during the August 14, 2003 blackout, other subsequent system events, and simulations of generating unit response to similar system conditions. The Reactive Power output observed during field-forcing in these events and simulations approaches a value equal to 150 percent of the Real Power (MW) capability of the generating unit when the generator is operating at its Real Power capability. In the SPCS technical reference document, two operating conditions were examined based on these events and simulations: (1) when the unit is operating at rated Real Power in MW with a level of Reactive Power output in Mvar which is equivalent to 150 percent times the rated MW value (representing some level of field-forcing) and (2) when the unit is operating at its declared low active Real Power operating limit (e.g., 40 percent of rated Real Power) with a level of Reactive Power output in Mvar which is equivalent to 175 percent times the rated MW value (representing some additional level of field-forcing).

Both conditions noted above are evaluated with the GSU transformer high-side voltage at 0.85 per unit. These load operating points are believed to be conservatively high levels of Reactive Power out of the generator with a 0.85 per unit high-side voltage which was based on these observations. However, for the purposes of this standard it was determined that the second load point (40 percent) offered no additional benefit and only increased the complexity for an entity to determine how to comply with the standard. Given the conservative nature of the criteria, which may not be achievable by all generating units, an alternate method is provided to determine the Reactive Power output by simulation. Also, to account for Reactive Power losses in the GSU transformer, a reduced level of output of 120 percent times the rated MW value is provided for relays applied at the high-side of the GSU transformer and on Elements that connect a GSU transformer to the Transmission system and are used exclusively to export energy directly from a BES generating unit or generating plant.

The phrase, "while maintaining reliable fault protection" in Requirement R1, describes that the Generator Owner, Transmission Owner, and Distribution Provider is to comply with this standard while achieving its desired protection goals. Load-responsive protective relays, as addressed within this standard, may be intended to provide a variety of backup protection functions, both within the generating unit or generating plant and on the Transmission system, and this standard is not intended to result in the loss of these protection functions. Instead, it is suggested that the

[17] http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Gen%20Prot%20Coordination%20Technical%20Reference%20Document.pdf

Generator Owner, Transmission Owner, and Distribution Provider consider both the requirement within this standard and its desired protection goals, and perform modifications to its protective relays or protection philosophies as necessary to achieve both.
For example, if the intended protection purpose is to provide backup protection for a failed Transmission breaker, it may not be possible to achieve this purpose while complying with this standard if a simple mho relay is being used. In this case, it may be possible to meet this purpose by replacing the legacy relay with a modern advanced-technology relay that can be set using functions such as load encroachment. It may otherwise be necessary to reconsider whether this is an appropriate method of achieving protection for the failed Transmission breaker, and whether this protection can be better provided by, for example, applying a breaker failure relay with a transfer trip system.

Requirement R1 establishes that the Generator Owner, Transmission Owner, and Distribution Provider must understand the applications of Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria ("Table 1") in determining the settings that it must apply to each of its load-responsive protective relays to prevent an unnecessary trip of its generator during the system conditions anticipated by this standard.

Applicability

To achieve the reliability objective of this standard it is necessary to include all load-responsive protective relays that are affected by increased generator output in response to system disturbances. This standard is therefore applicable to relays applied by the Generator Owner, Transmission Owner, and Distribution Provider at the terminals of the generator, GSU transformer, unit auxiliary transformer (UAT), Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, and Elements utilized in the aggregation of dispersed power producing resources.

The Generator Owner's interconnection facility (in some cases labeled a "transmission Facility" or "generator leads") consists of Elements between the GSU transformer and the interface with the portion of the Bulk Electric System (BES) where Transmission Owners take over the ownership. This standard does not use the industry recognized term "generator interconnection Facility" consistent with the work of Project 2010-07 (Generator Requirements at the Transmission Interface), because the term generator interconnection Facility implies ownership by the Generator Owner. Instead, this standard refers to these Facilities as "Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant" to include these Facilities when they are also owned by the Transmission Owner or Distribution Provider. The load-responsive protective relays in this standard for which an entity shall be in compliance is dependent on the location and the application of the protective functions. Figures 1, 2, and 3 illustrate various generator interface connections with the Transmission system.

Figure 1

Figure 1 is a single (or set) of generators connected to the Transmission system through a radial line that is used exclusively to export energy directly from a BES generating unit or generating plant to the network. The protective relay R1 located on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the relaying located at Bus A and in some cases Bus B. Under this application, relay R1 would apply the loadability requirement in PRC-025-2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

The protective relay R2 located on the incoming source breaker CB102 to the generating plant applies relaying that primarily protects the line by using line differential relaying from Bus A to B and also provides backup protection to the transmission relaying at Bus B. In this case, the relay function that provides line protection would apply the loadability requirement in PRC-025-2 and an appropriate option for the application from Table 1 (e.g., 15a, 15b, 16a, 16b, 18, and 19) for phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications. The backup protective function would apply the requirement in the PRC-025-2 standard using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

Since Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are applicable to the standard, the loadability for relays applied on these Elements as shown in the shaded area of Figure 1 (i.e., CB102 and CB103) must be considered. If relay R2 or R3 is set with an element directional toward the transmission system (e.g., Buses B, C and D) or are non-directional, the relay would be affected by increased generator output in response to system disturbances and must meet the loadability setting criteria described in the standard. If relay R2 or R3 is set with an element directional toward the generator (e.g., Bus A), the relay would not be affected by increased generator output in response to system disturbances; therefore, the entity would not be required to apply the loadability setting criteria described in this standard.

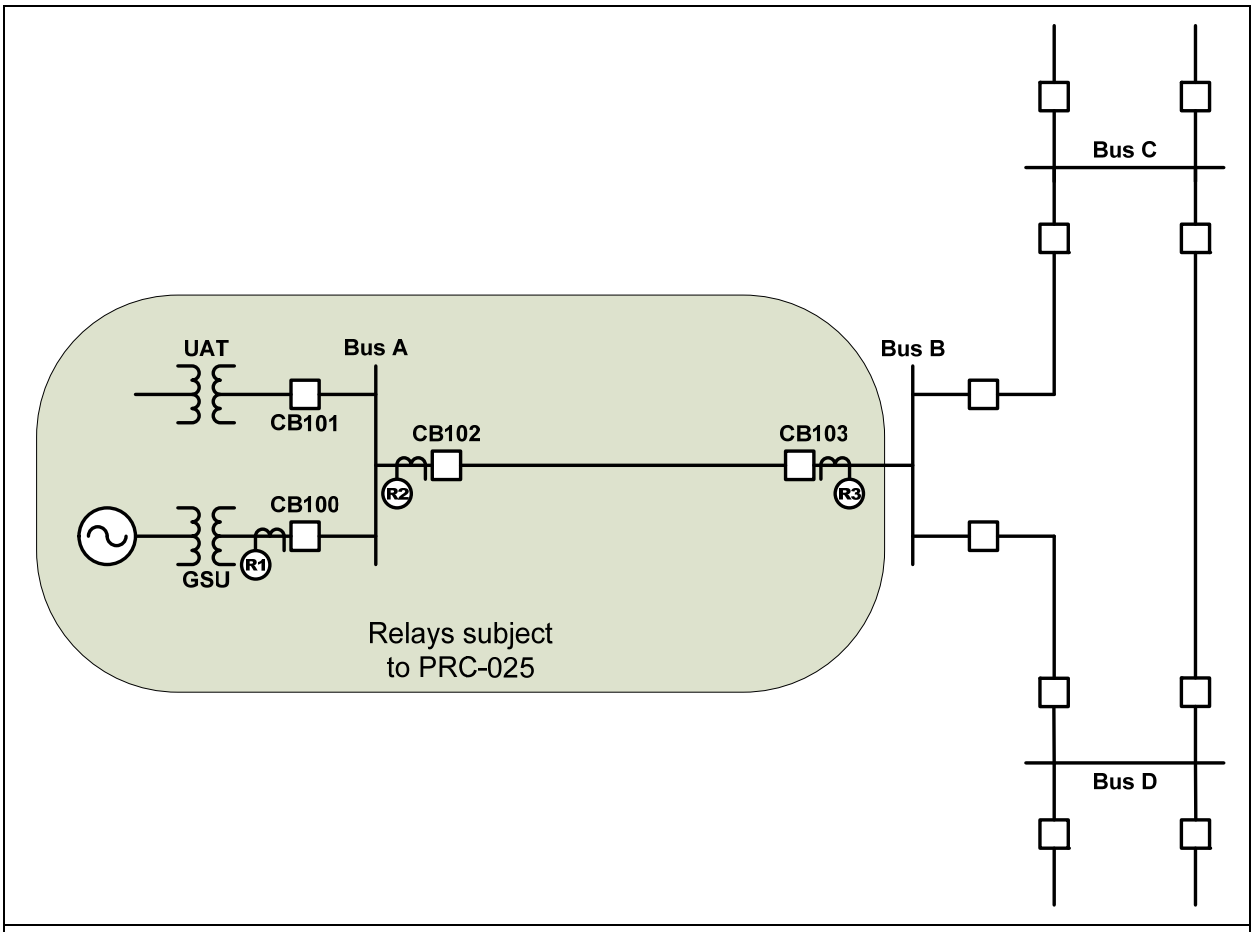


Figure 1. Generation exported through a single radial line.

Figure 2

Figure 2 is an example of a single (or set) of generators connected to the Transmission system through multiple lines that are used exclusively to export energy directly from a BES generating unit or generating plant to the network. The protective relay R1 on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the Transmission relaying located at Bus A and in some cases Bus B. Under this application, relay R1 would apply the loadability requirement in PRC-025-2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

The protective relays R2 and R3 located on the incoming source breakers CB102 and CB103 to the generating plant applies relaying that primarily protects the line from Bus A to B and also provides backup protection to the transmission relaying at Bus B. In this case, the relay function that provides line protection would apply the loadability requirement in PRC-025-2 and an appropriate option for the application from Table 1 (e.g., Options 15a, 15b, 16a, 16b, 18, and 19) for phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-

based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications. The backup protective function would apply the requirement in the PRC-025-2 standard using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

Since Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are applicable to the standard, the loadability for relays applied on these Elements as shown in the shaded area of Figure 2 (i.e., CB102, CB103, CB104, and CB105) must be considered. If relay R2, R3, R4, or R5 is set with an element directional toward the transmission system (e.g., Buses B, C and D) or are non-directional, the relay would be affected by increased generator output in response to system disturbances and must meet the loadability setting criteria described in the standard. If relay R2, R3, R4, or R5 is set with an element directional toward the generator (e.g., Bus A), the relay would not be affected by increased generator output in response to system disturbances; therefore, the entity would not be required to apply the loadability setting criteria described in this standard.

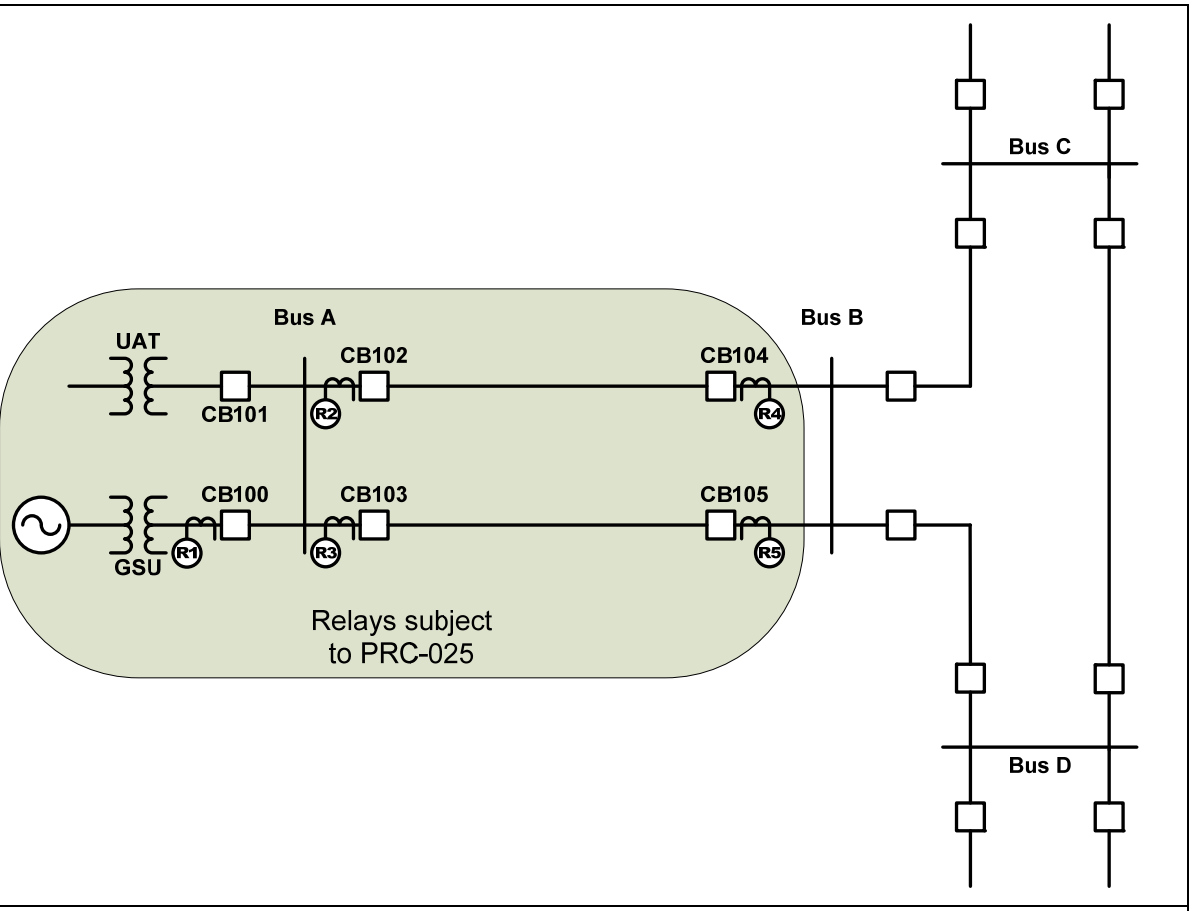


Figure 2. Generation exported through multiple radial lines.

Figure 3

Figure 3 is example a single (or set) of generators exporting power dispersed through multiple lines to the Transmission system through a network. The protective relay R1 on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the Transmission relaying located at Bus A and in some cases Bus C or Bus D. Under this application, relay R1 would apply the applicable loadability requirement in PRC-025-2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

Since the lines from Bus A to Bus C and from Bus A to Bus D are part of the transmission network, these lines would not be considered as Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Therefore, the applicable responsible entity would be responsible for the load-responsive protective relays R2 and R3 under the PRC-023 standard. The applicable responsible entity's loadability relays R4 and R5 located on the breakers CB104 and CB105 at Bus C and D are also subject to the requirements of the PRC-023 standard.

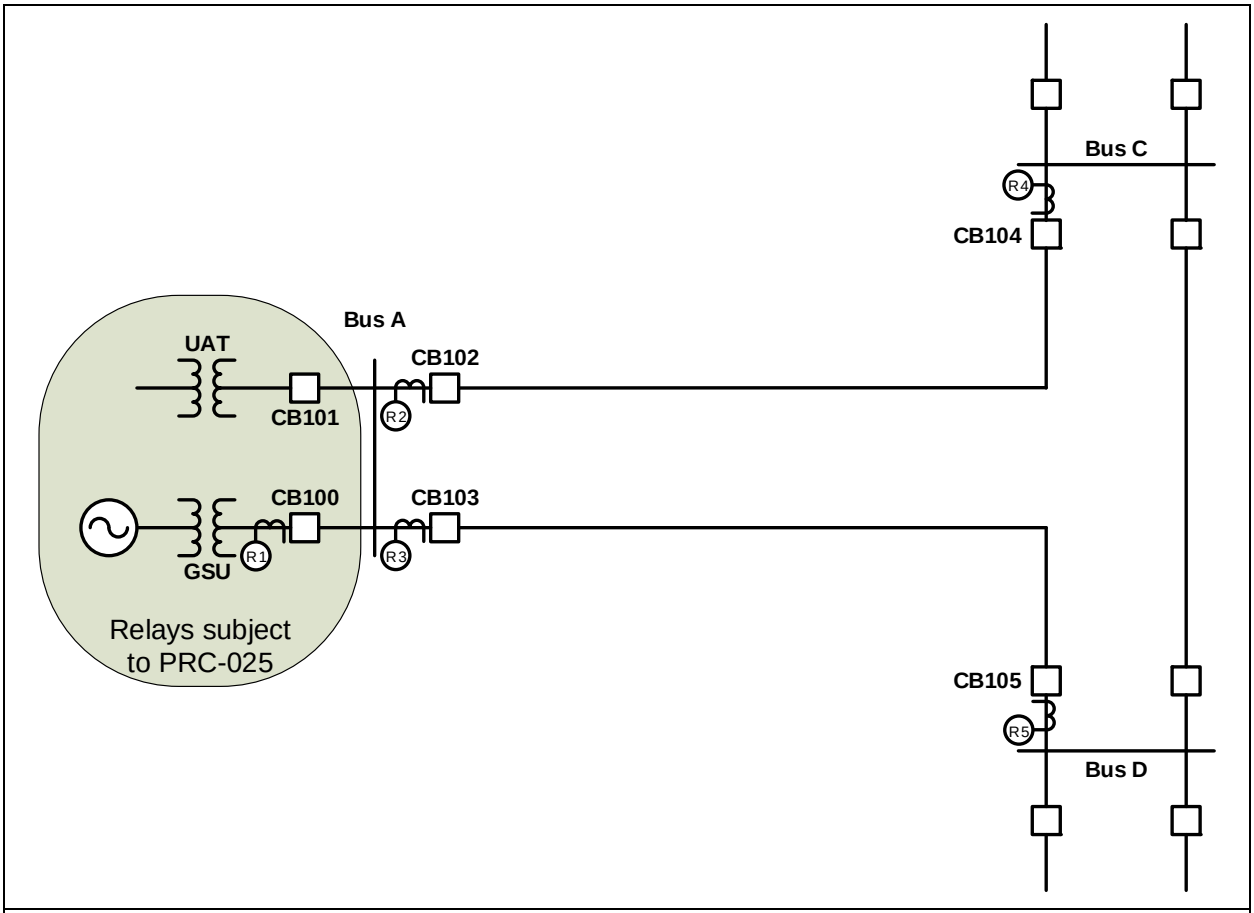


Figure 3. Generation exported through a network.

Elements utilized in the aggregation of dispersed power producing resources (in some cases referred to as a "collector system") consist of the Elements between individual generating units and the common point of interconnection to the Transmission system.

This standard is also applicable to the UATs that supply station service power to support the on-line operation of generating units or generating plants. These transformers are variably referred to as station power, unit auxiliary transformer(s), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Inclusion of these transformers satisfies a directive in FERC Order No. 733, paragraph 104, which directs NERC to include in this standard a loadability requirement for relays used for overload protection of the UAT(s) that supply normal station service for a generating unit.

Synchronous Generator Performance

When a synchronous generator experiences a depressed voltage, the generator will respond by increasing its Reactive Power output to support the generator terminal voltage. This operating condition, known as "field-forcing," results in the Reactive Power output exceeding the steady-state capability of the generator and may result in operation of generation system load-responsive protective relays if they are not set to consider this operating condition. The ability of the generating unit to withstand the increased Reactive Power output during field-forcing is limited by the field winding thermal withstand capability. The excitation limiter will respond to begin reducing the level of field-forcing in as little as one second, but may take much longer, depending on the level of field-forcing given the characteristics and application of the excitation system. Since this time may be longer than the time-delay of the generator load-responsive protective relay, it is important to evaluate the loadability to prevent its operation for this condition.

The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the GSU transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage. The criteria established within Table 1 are based on 0.85 per unit of the line nominal voltage. This voltage was widely observed during the events of August 14, 2003, and was determined during the analysis of the events to represent a condition from which the System may have recovered, had other undesired behavior not occurred.

The dynamic load levels specified in Table 1 under column "Setting Criteria" are representative of the maximum expected apparent power during field-forcing with the Transmission system voltage at 0.85 per unit, for example, at the high-side of the GSU transformer. These values are based on records from the events leading to the August 14, 2003 blackout, other subsequent System events, and simulations of generating unit responses to similar conditions. Based on these observations, the specified criteria represent conservative but achievable levels of Reactive Power output of the generator with a 0.85 per unit high-side voltage at the point of interconnection.

The dynamic load levels were validated by simulating the response of synchronous generating units to depressed Transmission system voltages for 67 different generating units. The generating units selected for the simulations represented a broad range of generating unit and excitation system characteristics as well as a range of Transmission system interconnection characteristics. The simulations confirmed, for units operating at or near the maximum Real Power output, that it is possible to achieve a Reactive Power output of 1.5 times the rated Real Power output when the Transmission system voltage is depressed to 0.85 per unit. While the simulations demonstrated that all generating units may not be capable of this level of Reactive Power output, the simulations confirmed that approximately 20 percent of the units modeled in the simulations could achieve these levels. On the basis of these levels, Table 1, Options 1a (i.e., 0.95 per unit) and 1b (i.e., 0.85 per unit), for example, are based on relatively simple, but conservative calculations of the high-side nominal voltage. In recognition that not all units are capable of achieving this level of output Option 1c (i.e., simulation) was developed to allow the Generator Owner, Transmission Owner, or Distribution Provider to simulate the output of a generating unit when the simple calculation is not adequate to achieve the desired protective relay setting.

Dispersed Generation

This standard is applicable to dispersed generation such as wind farms and solar arrays. The intent of this standard is to ensure the aggregate facility as defined above will remain on-line during a system disturbance; therefore, all output load-responsive protective relays associated with the facility are included in PRC-025.

Dispersed power producing resources with aggregate capacity greater than 75 MVA (gross aggregate nameplate rating) utilizing a system designed primarily for aggregating capacity, connected at a common point at a voltage of 100 kV or above are included in PRC-025-2. Load-responsive protective relays that are applied on Elements that connect these individual generating units through the point of interconnection with the Transmission system are within the scope of PRC-025-2. For example, feeder overcurrent relays and feeder step-up transformer overcurrent relays (see Figure 5) are included because these relays are challenged by generator loadability.

In the case of solar arrays where there are multiple voltages utilized in converting the solar panel DC output to a 60Hz AC waveform, the “terminal” is defined at the 60Hz AC output of the inverter-solar panel combination.

Asynchronous Generator Performance

Asynchronous generators will not respond to a disturbance with the same magnitude of apparent power that a synchronous generator will respond. Asynchronous generators, though, will support the system during a disturbance. Inverter-based generators will provide Real Power and Reactive Power (depending on the installed capability and regional grid code requirements) and may even provide a faster Reactive Power response than a synchronous generator. The magnitude of this response may slightly exceed the steady-state capability of the inverter but only for a short duration before limiter functions will activate. Although induction generators will not inherently supply Reactive Power, induction generator installations may include static and/or dynamic

reactive devices, depending on regional grid code requirements. These devices also may provide Real Power during a voltage disturbance. Thus, tripping asynchronous generators may exacerbate a disturbance.

Inverters, including wind turbines (i.e., Types 3 and 4) and photovoltaic solar, are commonly available with 0.90 power factor capability. This calculates to an apparent power magnitude of 1.11 per unit of rated MW.

Similarly, induction generator installations, including Type 1 and Type 2 wind turbines, often include static and/or dynamic reactive devices to meet grid code requirements and may have apparent power output similar to inverter-based installations; therefore, it is appropriate to use the criteria established in the Table 1 (i.e., Options 4, 5, 6, 10, 11, 12, 17, 18, and 19) for asynchronous generator installations.

Synchronous Generator Simulation Criteria

The Generator Owner, Transmission Owner, or Distribution Provider who elects a simulation option to determine the synchronous generator performance on which to base relay settings may simulate the response of a generator by lowering the Transmission system voltage at the remote end of the line or at the high-side of the GSU transformer (as prescribed by the Table 1 criteria). This can be simulated by means such as modeling the connection of a shunt reactor at the remote end of the line or at the GSU transformer high-side to lower the voltage to 0.85 per unit prior to field-forcing. The resulting step change in voltage is similar to the sudden voltage depression observed in parts of the Transmission system on August 14, 2003. The initial condition for the simulation should represent the generator at 100 percent of the maximum gross Real Power capability in MW as reported to the Transmission Planner. The simulation is used to determine the Reactive Power and voltage to be used to calculate relay setting limits. The Reactive Power value obtained by simulation is the highest simulated level of Reactive Power achieved during field-forcing. The voltage value obtained by simulation is the simulated voltage coincident with the highest Reactive Power achieved during field-forcing. These values of Reactive Power and voltage correspond to the minimum apparent impedance and maximum current observed during field-forcing.

Phase Distance Relay – Directional Toward Transmission System (e.g., 21)

Generator phase distance relays that are directional toward the Transmission system, whether applied for the purpose of primary or backup GSU transformer protection, external system backup protection, or both, were noted during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generating units or generating plants, which contributed to the scope of that disturbance. Specifically, eight generators are known to have been tripped by this protection function. These options establish criteria for phase distance relays that are directional toward the Transmission system to help assure that generators, to the degree possible, will provide System support during disturbances in an effort to minimize the scope of those disturbances.

The phase distance relay that is directional toward the Transmission system measures impedance derived from the quotient of generator terminal voltage divided by generator stator current.

Section 4.6.1.1 of IEEE C37.102-2006, "Guide for AC Generator Protection," describes the purpose of this protection as follows (emphasis added):

> *"The distance relay applied for this function is intended to isolate the generator from the power system for a fault* ***that is not cleared by the transmission line breakers.*** *In some cases this relay is set with a very long reach. A condition that causes the generator voltage regulator to boost generator excitation for a sustained period may result in the system apparent impedance, as monitored at the generator terminals, to fall within the operating characteristics of the distance relay. Generally, a distance relay setting of 150% to 200% of the generator MVA rating at its rated power factor has been shown to provide good coordination for stable swings, system faults involving in-feed, and* ***normal loading conditions.*** *However, this setting may also result in failure of the relay to operate for some line faults where the line relays fail to clear. It is recommended that the setting of these relays be evaluated between the generator protection engineers and the system protection engineers* ***to optimize coordination while still protecting the turbine generator****. Stability studies may be needed to help determine a set point to optimize protection and coordination. Modern excitation control systems include overexcitation limiting and protection devices to protect the generator field, but the time delay before they reduce excitation is several seconds. In distance relay applications for which the voltage regulator action could cause an incorrect trip, consideration should be given to reducing the reach of the relay and/or coordinating the tripping time delay with the time delays of the protective devices in the voltage regulator. Digital multifunction relays equipped with load encroachment binders [sic] can prevent misoperation for these conditions.* ***Within its operating zone, the tripping time for this relay must coordinate with the longest time delay for the phase distance relays on the transmission lines connected to the generating substation bus.*** *With the advent of multifunction generator protection relays, it is becoming more common to use two-phase distance zones. In this case, the second zone would be set as previously described. When two zones are applied for backup protection, the first zone is typically set to see the substation bus (120% of the GSU transformer). This setting should be checked for coordination with the zone-1 element on the shortest line off of the bus. The normal zone-2 time-delay criteria would be used to set the*

delay for this element. Alternatively, zone-1 can be used to provide high-speed protection for phase faults, in addition to the normal differential protection, in the generator and iso-phase bus with partial coverage of the GSU transformer. For this application, the element would typically be set to 50% of the transformer impedance with little or no intentional time delay. It should be noted that it is possible that this element can operate on an out-of-step power swing condition and provide misleading targeting."

If a mho phase distance relay that is directional toward the Transmission system cannot be set to maintain reliable fault protection and also meet the criteria in accordance with Table 1, there may be other methods available to do both, such as application of blinders to the existing relays, implementation of lenticular characteristic relays, application of offset mho relays, or implementation of load encroachment characteristics. Some methods are better suited to improving loadability around a specific operating point, while others improve loadability for a wider area of potential operating points in the R-X plane. The operating point for a stressed System condition can vary due to the pre-event system conditions, severity of the initiating event, and generator characteristics such as Reactive Power capability.

For this reason, it is important to consider the potential implications of revising the shape of the relay characteristic to obtain a longer relay reach, as this practice may result in a relay characteristic that overlaps the capability of the generating unit when operating at a Real Power output level other than 100 percent of the maximum Real Power capability. Overlap of the relay characteristic and generator capability could result in tripping the generating unit for a loading condition within the generating unit capability. The examples in Appendix E of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document illustrate the potential for, and need to avoid, encroaching on the generating unit capability.

Phase Instantaneous Overcurrent Relay (e.g., 50)

The 50 element is a non-directional overcurrent element that typically has no intentional time delay. The primary application is for close-in high current faults where high speed operation is required or preferred. The instantaneous overcurrent elements are subject to the same loadability issues as the time overcurrent elements referenced in this standard.

Phase Time Overcurrent Relay (e.g., 51)

See Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function. Note that the setting criteria established within the Table 1 options differs from the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the Table 1 setting criteria are based on the maximum expected generator Real Power output based on whether the generator is a synchronous or asynchronous unit.

Phase Time Overcurrent Relay – Voltage-Restrained (e.g., 51V-R)

Phase time overcurrent voltage-restrained relays (e.g., 51V-R), which change their sensitivity as a function of voltage, whether applied for the purpose of primary or backup GSU transformer protection, for external system phase backup protection, or both, were noted, during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generating units or generating plants, contributing to the scope of that disturbance. Specifically, 20 generators are known to have been tripped by voltage-restrained and voltage-controlled protection functions together. These protective functions are variably referred to by IEEE function numbers 51V, 51R, 51VR, 51V/R, 51V-R, or other terms. See Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.

Phase Time Overcurrent Relay – Voltage Controlled (e.g., 51V-C)

Phase time overcurrent voltage-controlled relays (e.g., 51V-C), enabled as a function of voltage, are variably referred to by IEEE function numbers 51V, 51C, 51VC, 51V/C, 51V-C, or other terms. See Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.

Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67)

See Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of the phase time overcurrent protection function. The basis for setting directional and non-directional overcurrent relays is similar. Note that the setting criteria established within the Table 1 options differs from of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the Table 1 setting criteria are based on the maximum expected generator Real Power output based on whether the generator is a synchronous or asynchronous unit.

Table 1, Options

Introduction

The margins in the Table 1 options are based on guidance found in the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the GSU transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage.

Relay Connections

Figures 4 and 5 below illustrate the connections for each of the Table 1 options provided in PRC-025-2, Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria.

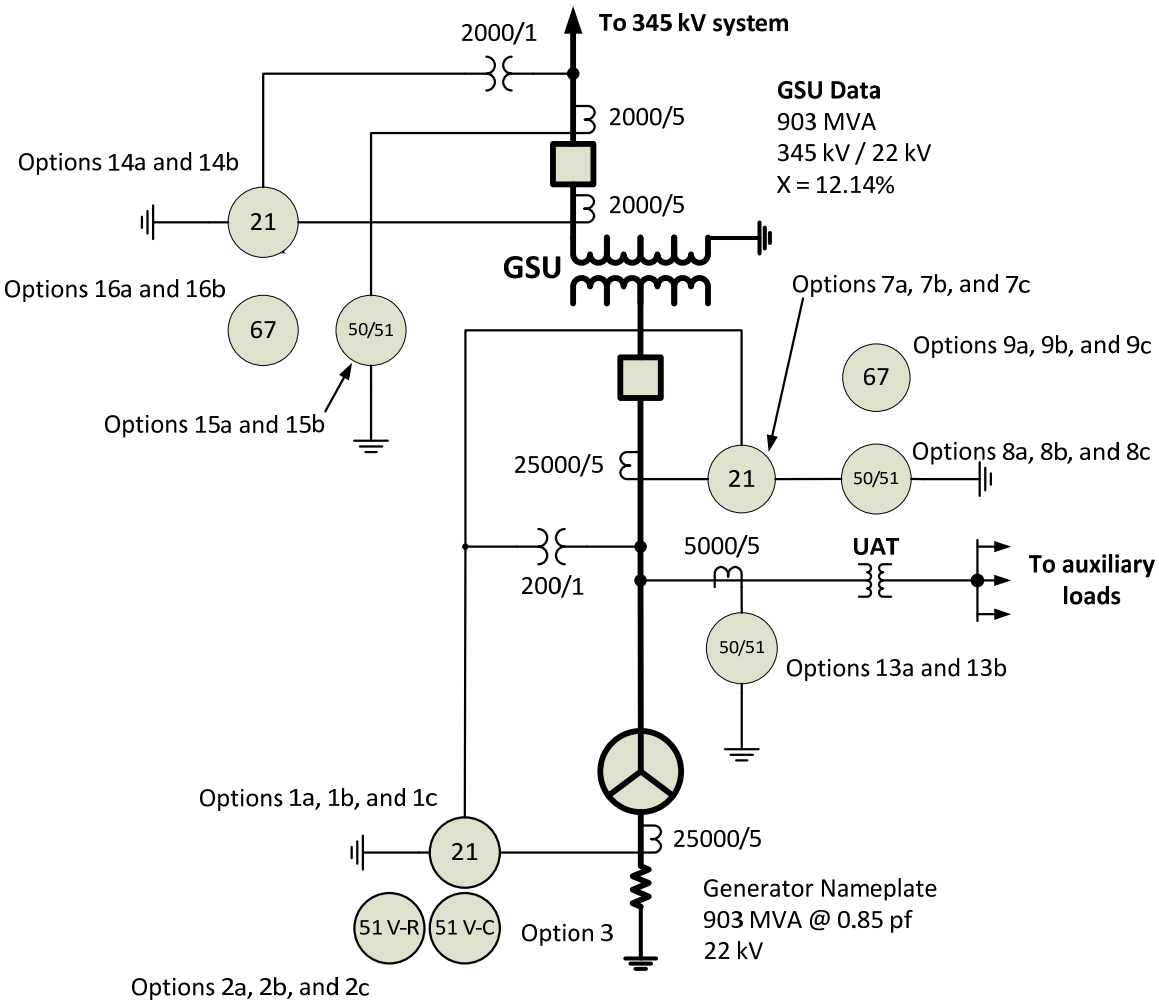


Figure 4. Relay Connection for corresponding synchronous options.

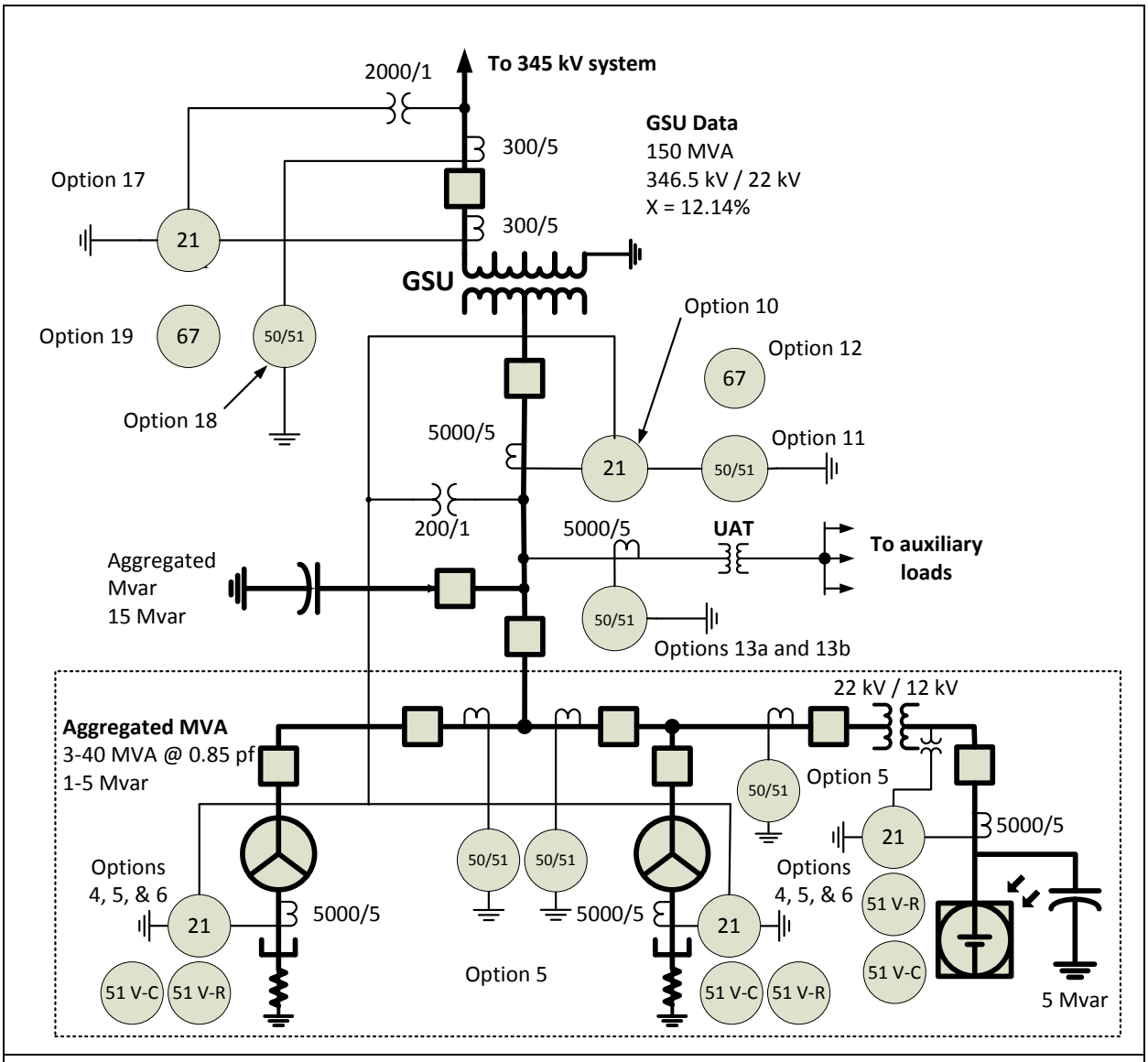


Figure 5. Relay Connection for corresponding asynchronous options including inverter-based installations.

Synchronous Generators Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Options 1a, 1b, and 1c)

Table 1, Options 1a, 1b, and 1c, are provided for assessing loadability for synchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 1a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 1b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more in-depth and precise method for setting of the impedance element than Option 1a.

Option 1c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the impedance element overall.

For Options 1a and 1b, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 1c, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Synchronous Generators Phase Overcurrent Relay – (e.g., 50, 51, or 51V-R – Voltage Restrained) (Options 2a, 2b, and 2c)

Table 1, Options 2a, 2b, and 2c, are provided for assessing loadability for synchronous generators applying phase overcurrent relays (e.g., 50 or 51) or voltage-restrained (e.g., 51V-R) which changes its sensitivity as a function of voltage ("voltage-restrained"). These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 2a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 2b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer as well as for the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved.

This calculation is a more in-depth and precise method for setting of the overcurrent element than Option 2a.

Option 2c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 2a and 2b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 2c, the overcurrent element shall be set greater than the calculated current derived from 115 percent of both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Synchronous Generators Phase Time Overcurrent Relay – Voltage Controlled (e.g., 51V-C) (Option 3)

Table 1, Option 3, is provided for assessing loadability for synchronous generators applying phase time overcurrent relays which are enabled as a function of voltage ("voltage-controlled"). These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 3 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 3, the voltage control setting shall be set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

Asynchronous Generators Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 4)

Table 1, Option 4 is provided for assessing loadability for asynchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are

based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 4 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 4, the impedance element shall be set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Asynchronous Generators Phase Overcurrent Relay – (e.g., 50, 51, or 51V-R – Voltage Restrained) (Options 5a and 5b)

Table 1, Option 5a is provided for assessing loadability for asynchronous generators applying phase overcurrent relays (e.g., 50 or 51) or voltage-restrained (e.g., 51V-R) which changes its sensitivity as a function of voltage ("voltage-restrained"). These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 5a calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 5a, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

For Option 5b, the overcurrent element shall be set to exceed the maximum capability of the asynchronous resource and applicable equipment (e.g., windings, power electronics, cables, or bus). This is determined by summing the total current capability of the generation equipment behind the overcurrent element and any static or dynamic Reactive Power devices that contribute to the power flow through the overcurrent element. The overcurrent element shall be set to not infringe upon the resource capability with worst case documented tolerances applied to the setting. Figure A illustrates that the overcurrent element does not infringe upon the asynchronous resource capability. The upper hashed area of Figure A represents Exclusion 7.

Asynchronous Generator Phase Time Overcurrent Relays – Voltage Controlled (e.g., 51V-C) (Option 6)

Table 1, Option 6, is provided for assessing loadability for asynchronous generators applying phase time overcurrent relays which are enabled as a function of voltage ("voltage-controlled"). These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 6 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 6, the voltage control setting shall be set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

Generator Step-up Transformer (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (e.g., 21) (Options 7a, 7b, and 7c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Options 7a, 7b, and 7c, are provided for assessing loadability of phase distance relays that are directional toward the Transmission system and connected to the generator-side of the GSU transformer of a synchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 14.

Option 7a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 7b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on the 0.85 per unit nominal voltage, at the high-side terminals of the GSU transformer, as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more in-depth and precise method for setting the impedance element than Option 7a.

Option 7c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more in-depth and precise method for setting the impedance element than Options 7a or 7b.

For Options 7a and 7b, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value (derived from the generator nameplate MVA rating at rated power factor).

For Option 7c, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase Overcurrent Relay (e.g., 50 or 51) (Options 8a, 8b and 8c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within the Table 1 options differs from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform loadability threshold of 200 percent of the generator

nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 8a, 8b, and 8c, are provided for assessing loadability of phase overcurrent relays that are connected to the generator-side of the GSU transformer of a synchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 15.

Option 8a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 8b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on the 0.85 per unit nominal voltage, at the high-side terminals of the GSU transformer, as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more in-depth and precise method for setting the overcurrent element than Option 8a.

Option 8c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more in-depth and precise method for setting the overcurrent element than Options 8a or 8b.

For Options 8a and 8b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value (derived from the generator nameplate MVA rating at rated power factor).

For Option 8c, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Options 9a, 9b and 9c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the

setting criteria established within the Table 1 options differs from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 9a, 9b, and 9c, are provided for assessing loadability of phase directional overcurrent relays directional toward the Transmission System that are connected to the generator-side of the GSU transformer of a synchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 16.

Option 9a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 9b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on the 0.85 per unit nominal voltage, at the high-side terminals of the GSU transformer, as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more in-depth and precise method for setting the overcurrent element than Option 9a.

Option 9c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more in-depth and precise method for setting the overcurrent element than Options 9a or 9b.

For Options 9a and 9b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value (derived from the generator nameplate MVA rating at rated power factor).

For Option 9c, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 10)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Table 1, Option 10 is provided for assessing loadability for GSU transformers applying phase distance relays that are directional toward the Transmission System that are connected to the generator-side of the GSU transformer of an asynchronous generator. These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. For applications where the relay is connected on the high-side of the GSU transformer, use Option 17.

Option 10 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; hence the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 10, the impedance element shall be set less than the calculated impedance, derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase Overcurrent Relay (e.g., 50 or 51) (Option 11)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within the Table 1 options differs from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 11 is provided for assessing loadability of phase overcurrent relays that are connected to the generator-side of the GSU transformer of an asynchronous generator. For

applications where the relay is connected on the high-side of the GSU transformer, use Option 18.

Option 11 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; hence the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 11, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Option 12)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within the Table 1 options differs from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 12 is provided for assessing loadability of phase directional overcurrent relays directional toward the Transmission System that are connected to the generator-side of the GSU transformer of an asynchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 19.

Option 12 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; hence the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 12, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Unit Auxiliary Transformers Phase Overcurrent Relay (e.g., 50 or 51) (Options 13a and 13b)

In FERC Order No. 733, paragraph 104, directs NERC to include in this standard a loadability requirement for relays used for overload protection of the UAT that supply normal station service for a generating unit. For the purposes of this standard, UATs provide the overall station power to support the unit at its maximum gross operation.

Table 1, Options 13a and 13b provide two options for addressing phase overcurrent relaying applied at the high-side of UATs. The transformer high-side winding may be directly connected to the transmission grid or at the generator isolated phase bus (IPB) or iso-phase bus. Phase overcurrent relays applied at the high-side of the UAT that remove the transformer from service resulting in an immediate (e.g., via lockout or auxiliary tripping relay operation) or consequential trip of the associated generator are to be compliant with the relay setting criteria in this standard. Due to the complexity of the application of low-side overload relays for single or multi-winding transformers, phase overcurrent relaying applied at the low-side of the UAT are not addressed in this standard. These relays include, but are not limited to, a relay used for arc flash protection, feeder protection relays, breaker failure, and relays whose operation may result in a generator runback. Although the UAT is not directly in the output path from the generator to the Transmission system, it is an essential component for operation of the generating unit or plant.

Refer to the Figures 6 and 7 below for example configurations:

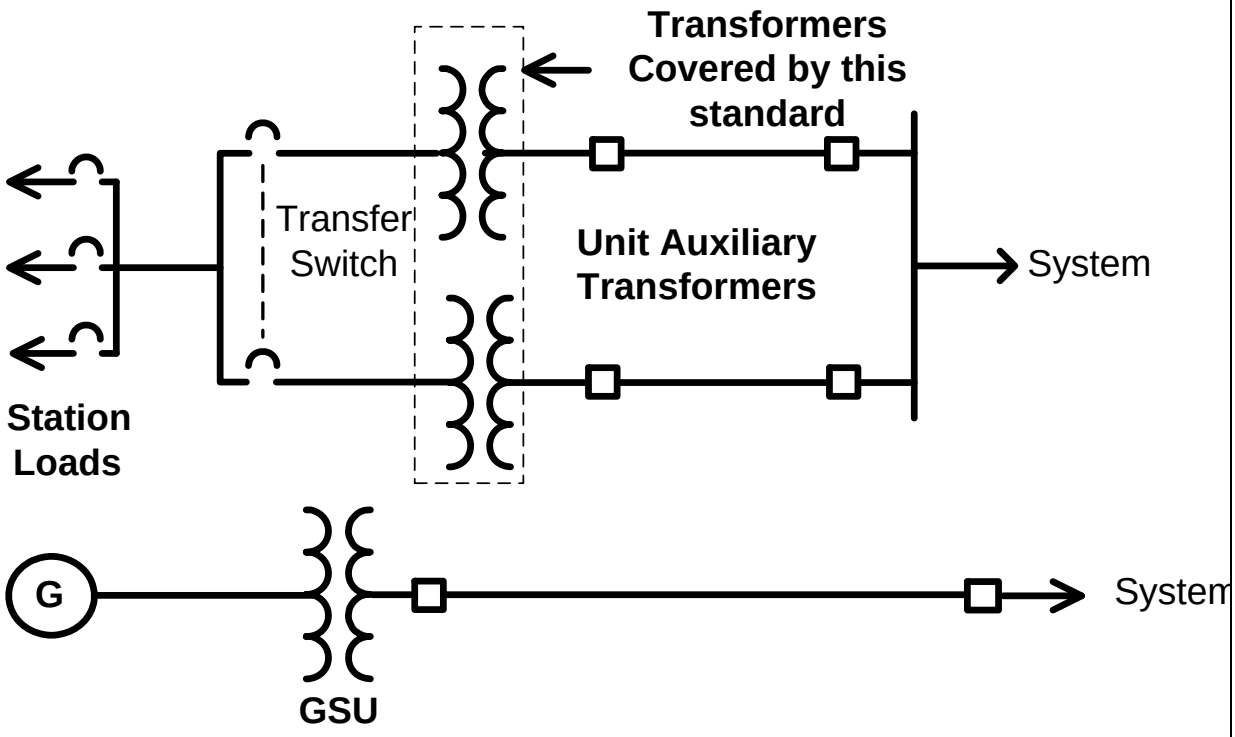


Figure-6 – Auxiliary Power System (independent from generator).

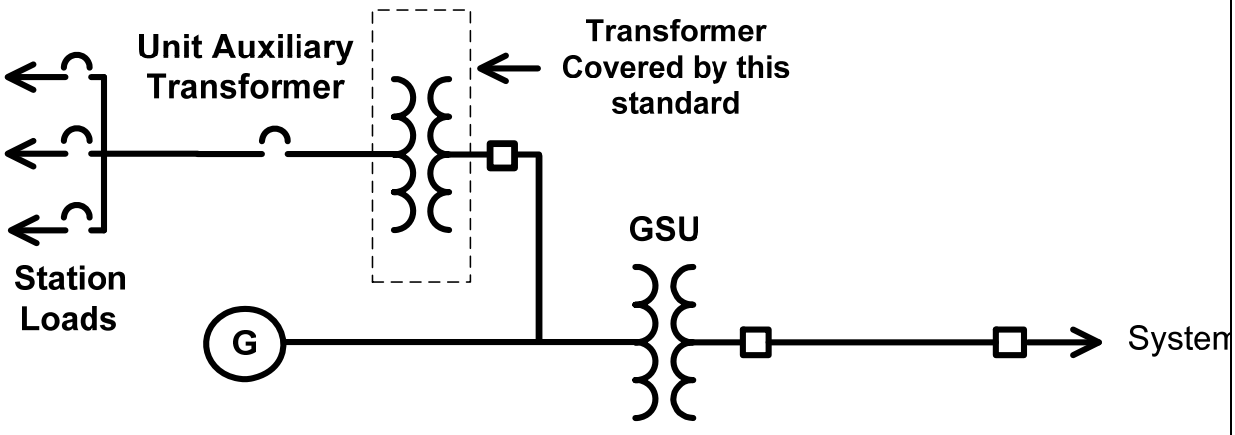


Figure-7 – Typical auxiliary power system for generation units or plants.

The UATs supplying power to the unit or plant electrical auxiliaries are sized to accommodate the maximum expected overall UAT load demand at the highest generator output. Although the transformer nameplate MVA size normally includes capacity for future loads as well as capacity for starting of large induction motors on the original unit or plant design, the nameplate MVA capacity of the transformer may be near full load.

Because of the various design and loading characteristics of UATs, two options (i.e., 13a and 13b) are provided to accommodate an entity's protection philosophy while preventing the UAT transformer phase overcurrent relays from operating during the dynamic conditions anticipated by this standard.

Options 13a and 13b are based on the transformer bus voltage corresponding to 1.0 per unit nominal voltage on the high-side winding of the UAT.

For Option 13a, the overcurrent element shall be set greater than 150 percent of the calculated current derived from the UAT maximum nameplate MVA rating. This is a simple calculation that approximates the stressed system conditions.

For Option 13b, the overcurrent element shall be set greater than 150 percent of the UAT measured current at the generator maximum gross MW capability reported to the Transmission Planner. This allows for a reduced setting compared to Option 13a and the entity's relay setting philosophy. This is a more involved calculation that approximates the stressed system conditions by allowing the entity to consider the actual load placed on the UAT based on the generator's maximum gross MW capability reported to the Transmission Planner.

The performance of the UAT loads during stressed system conditions (i.e., depressed voltages) is very difficult to determine. Rather than requiring responsible entities to determine the response of UAT loads to depressed voltage, the technical experts writing the standard elected to increase the margin to 150 percent from that used elsewhere in this standard (e.g., 115 percent) and use a generator bus voltage of 1.0 per unit. A minimum setting current based on 150 percent of maximum transformer nameplate MVA rating at 1.0 per unit generator bus voltage will provide adequate transformer protection based on IEEE C37.91 at full load conditions while providing sufficient relay loadability to prevent a trip of the UAT, and subsequent unit trip, due to increased UAT load current during stressed system voltage conditions. Even if the UAT is equipped with an automatic tap changer, the tap changer may not respond quickly enough for the conditions anticipated within this standard, and thus shall not be used to reduce this margin.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (e.g., 21) (Options 14a and 14b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers.

These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays connected on the Elements that connect a GSU transformer to the Transmission system (e.g., at the remote end of the line) that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 14 is used for these relays as well.

Table 1, Options 14a and 14b, establish criteria for phase distance relays directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 14a reflects a 0.85 per unit of the line nominal voltage; therefore, establishing that the impedance value used for applying the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant phase distance relays that are directional toward the Transmission system be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit of the line nominal voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 14b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 14a, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 14b, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Using simulation is a more involved, more precise setting of the impedance element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Time Overcurrent Relay (e.g., 50 or 51) (Options 15a and 15b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within the Table 1 options differs from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays connected on the Elements that connect a GSU transformer to the Transmission system (e.g., at the remote end of the line) that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 15 is used for these relays as well.

Table 1, Options 15a and 15b, establish criteria for phase instantaneous and/or time overcurrent relays to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 15a reflects a 0.85 per unit of the line nominal voltage at the relay location; therefore, establishing that the current value used for applying the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant phase instantaneous and/or time overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit of the line nominal voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 15b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 15a, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 15b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Options 16a and 16b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within the Table 1 options differs from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays connected on the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 16 is used for these relays as well.

Table 1, Options 16a and 16b, establish criteria for phase directional overcurrent relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 16a reflects a 0.85 per unit of the line nominal voltage at the relay location; therefore, establishing that the current value used for applying the interconnection Facilities phase directional overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit of the line nominal voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 16b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 16a, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that

equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 16b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 17)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Option 17 establishes criteria for phase distance relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. Option 17 applies a 1.0 per unit line nominal voltage at the relay location to calculate the impedance from the maximum aggregate nameplate MVA.

For Option 17, the impedance element shall be set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase Overcurrent Relay (e.g., 50 and 51) (Option 18)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within the Table 1 options differs from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical

reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 18 establishes criteria for phase overcurrent relays to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. Option 18 applies a 1.0 per unit line nominal voltage at the location of the relay to calculate the current from the maximum aggregate nameplate MVA.

For Option 18, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Option 19)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within the Table 1 options differs from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 19 establishes criteria for phase directional overcurrent relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. Option 19 applies a 1.0 per unit line nominal voltage at the relay location to calculate the current from the maximum aggregate nameplate MVA.

For Option 19, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Example Calculations

Introduction

Example Calculations.	
Input Descriptions	**Input Values**
Synchronous Generator nameplate (MVA @ rated pf):	$GEN_{Synch_nameplate} = 903\ MVA$
	$pf = 0.85$
Generator rated voltage (Line-to-Line):	$V_{gen_nom} = 22\ kV$
Real Power output in MW as reported to the TP:	$P_{Synch_reported} = 700.0\ MW$
Generator step-up (GSU) transformer rating:	$MVA_{GSU} = 903\ MVA$
GSU transformer reactance (903 MVA base):	$X_{GSU} = 12.14\%$
GSU transformer MVA base:	$MVA_{base} = 767.6\ MVA$
GSU transformer turns ratio:	$GSU_{ratio} = \frac{22\ kV}{346.5\ kV}$
High-side nominal system voltage (Line-to-Line):	$V_{nom} = 345\ kV$
Current transformer (CT) ratio:	$CT_{ratio} = \frac{25000}{5}$
Potential transformer (PT) ratio low-side:	$PT_{ratio} = \frac{200}{1}$
PT ratio high-side:	$PT_{ratio_hv} = \frac{2000}{1}$
Unit auxiliary transformer (UAT) nameplate:	$UAT_{nameplate} = 60\ MVA$
UAT low-side voltage:	$V_{UAT} = 13.8\ kV$
UAT CT ratio:	$CT_{UAT} = \frac{5000}{5}$
CT high voltage ratio:	$CT_{ratio_hv} = \frac{2000}{5}$
Reactive Power output of static reactive device:	$MVAR_{static} = 15\ Mvar$

Example Calculations.	
Reactive Power output of static reactive device generation:	$MVAR_{gen_static} = 5\ Mvar$
Asynchronous generator nameplate (MVA @ rated pf):	$GEN_{Asynch_nameplate} = 40\ MVA$
	$pf = 0.85$
Asynchronous CT ratio:	$CT_{Asynch_ratio} = \frac{5000}{5}$
Asynchronous high voltage CT ratio:	$CT_{Asynch_ratio_hv} = \frac{300}{5}$
CT remote substation bus	$CT_{ratio_remote_bus} = \frac{2000}{5}$

Example Calculations: Option 1a

Option 1a represents the simplest calculation for synchronous generators applying a phase distance relay (e.g., 21) directional toward the Transmission system.

Real Power output (P):

Eq. (1) $P = GEN_{Synch_nameplate} \times pf$

$P = 903\ MVA \times 0.85$

$P = 767.6\ MW$

Reactive Power output (Q):

Eq. (2) $Q = 150\% \times P$

$Q = 1.50 \times 767.6\ MW$

$Q = 1151.3\ Mvar$

Option 1a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (3) $V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$

$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$

$V_{gen} = 20.81\ kV$

Apparent power (S):

Eq. (4) $S = P_{Synch_reported} + jQ$

$S = 700.0\ MW + j1151.3\ Mvar$

$S = 1347.4\angle 58.7°\ MVA$

Primary impedance (Z_{pri}):

Eq. (5) $Z_{pri} = \frac{V_{gen}^2}{S^*}$

$Z_{pri} = \frac{(20.81\ kV)^2}{1347.4\angle -58.7°\ MVA}$

Example Calculations: Option 1a

$$Z_{pri} = 0.321\angle 58.7° \, \Omega$$

Secondary impedance (Z_{sec}):

Eq. (6) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.321\angle 58.7° \, \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.321\angle 58.7° \, \Omega \times 25$$

$$Z_{sec} = 8.035\angle 58.7° \, \Omega$$

To satisfy the 115% margin in Option 1a:

Eq. (7) $$Z_{\text{sec}\,limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\text{sec}\,limit} = \frac{8.035\angle 58.7° \, \Omega}{1.15}$$

$$Z_{\text{sec}\,limit} = 6.9873\angle 58.7° \, \Omega$$

$$\theta_{transient\ load\ angle} = 58.7°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (8) $$Z_{max} < \frac{|Z_{\text{sec}\,limit}|}{\cos\left(\theta_{MTA} - \theta_{transient\ load\ angle}\right)}$$

$$Z_{max} < \frac{6.9873 \, \Omega}{\cos(85.0° - 58.7°)}$$

$$Z_{max} < \frac{6.9873 \, \Omega}{0.896}$$

$$Z_{max} < \ 7.793\angle 85.0° \, \Omega$$

Example Calculations: Options 1b and 7b

Option 1b represents a more complex, more precise calculation for synchronous generators applying a phase distance relay (e.g., 21) directional toward the Transmission system. This option requires calculating low-side voltage taking into account voltage drop across the GSU transformer. Similarly these calculations may be applied to Option 7b for GSU transformers applying a phase distance relay (e.g., 21) directional toward the Transmission system.

Real Power output (P):

Eq. (9) $$P = GEN_{Synch_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (10) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on a 767.6 MVA base (MVA_{base}):

Real Power output (P):

Eq. (11) $$P_{pu} = \frac{P_{Synch_reported}}{MVA_{base}}$$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (12) $$Q_{pu} = \frac{Q}{MVA_{base}}$$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Example Calculations: Options 1b and 7b

Transformer impedance (X_{pu}):

Eq. (13) $$X_{pu} = X_{GSU(old)} \times \left(\frac{MVA_{base}}{MVA_{GSU}}\right)$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Estimate initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (14) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times \lceil V_{high-side} \rceil\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.7°$$

Eq. (15)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Example Calculations: Options 1b and 7b

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (16) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times \lceil V_{high-side} \rceil\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (17)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (18) $$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Apparent power (S):

Eq. (19) $$S = P_{Synch_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Example Calculations: Options 1b and 7b

Primary impedance (Z_{pri}):

Eq. (20) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(21.90\ kV)^2}{1347.4\angle -58.7°\ MVA}$$

$$Z_{pri} = 0.356\angle 58.7°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (21) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.356\angle 58.7°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.356\angle 58.7°\ \Omega \times 25$$

$$Z_{sec} = 8.900\angle 58.7°\ \Omega$$

To satisfy the 115% margin in Options 1b and 7b:

Eq. (22) $$Z_{\text{sec}\,limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\text{sec}\,limit} = \frac{8.900\angle 58.7°\ \Omega}{1.15}$$

$$Z_{\text{sec}\,limit} = 7.74\angle 58.7°\ \Omega$$

$$\theta_{transient\ load\ angle} = 58.7°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (23) $$Z_{max} < \frac{|Z_{\text{sec}\,limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{7.74\ \Omega}{\cos(85.0° - 58.7°)}$$

Example Calculations: Options 1b and 7b

$$Z_{max} < \frac{7.74\ \Omega}{0.8965}$$

$$Z_{max} < 8.633 \angle 85.0°\ \Omega$$

Example Calculations: Options 1c and 7c

Option 1c represents a more involved, more precise setting of the impedance element. This option requires determining maximum generator Reactive Power output during field-forcing and the corresponding generator bus voltage. Once these values are determined, the remainder of the calculation is the same as Options 1a and 1b.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.

In this simulation the following values are derived:

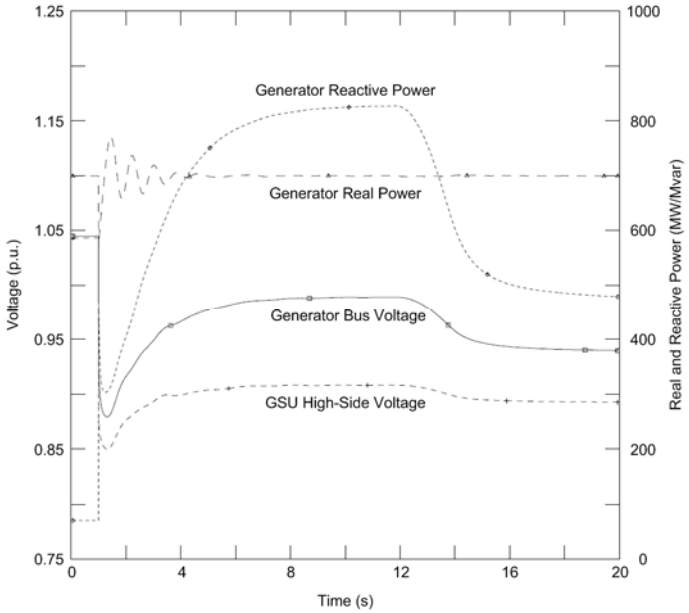
$$Q = 827.4\ Mvar$$

$$V_{bus_simulated} = 0.989 \times V_{gen_nom} = 21.76\ k\text{V}$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{Synch_reported} = 700.0\ MW$$

Example Calculations: Options 1c and 7c



Apparent power (S):

Eq. (24) $S = P_{Synch_reported} + jQ$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (25) $$Z_{pri} = \frac{V_{bus_simulated}^2}{S^*}$$

$$Z_{pri} = \frac{(21.76\ kV)^2}{1083.8\angle -49.8°\ MVA}$$

$$Z_{pri} = 0.437\angle 49.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (26) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.437\angle 49.8°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

Example Calculations: Options 1c and 7c

$$Z_{sec} = 0.437\angle 49.8° \, \Omega \times 25$$

$$Z_{sec} = 10.92\angle 49.8° \, \Omega$$

To satisfy the 115% margin in the requirement in Options 1c and 7c:

Eq. (27) $$Z_{\text{sec}\,limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\text{sec}\,limit} = \frac{10.92\angle 49.8° \, \Omega}{1.15}$$

$$Z_{\text{sec}\,limit} = 9.50\angle 49.8° \, \Omega$$

$$\theta_{transient\ load\ angle} = 49.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (28) $$Z_{max} < \frac{|Z_{\text{sec}\,limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{9.50 \, \Omega}{\cos(85.0° - 49.8°)}$$

$$Z_{max} < \frac{9.50 \, \Omega}{0.8171}$$

$$Z_{max} < \ 11.63\angle 85.0° \, \Omega$$

Example Calculations: Option 2a

Option 2a represents the simplest calculation for synchronous generators applying a phase overcurrent (e.g., 50, 51, or 51V-R) relay:

Real Power output (P):

Eq. (29) $$P = \ GEN_{Synch_nameplate} \times pf$$

$$P = 903 \, MVA \ \times 0.85$$

$$P = 767.6 \, MW$$

Example Calculations: Option 2a

Reactive Power output (Q):

Eq. (30) $Q = 150\% \times P$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Option 2a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (31) $V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (32) $S = P_{Synch_reported} + jQ$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4 \angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (33) $I_{pri} = \frac{S}{\sqrt{3} \times V_{gen}}$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 20.81\ kV}$$

$$I_{pri} = 37383\ A$$

Secondary current (I_{sec}):

Eq. (34) $I_{sec} = \frac{I_{pri}}{CT_{ratio}}$

$$I_{sec} = \frac{37383\ A}{\frac{25000}{5}}$$

Example Calculations: Option 2a

$$I_{sec} = 7.477\ A$$

To satisfy the 115% margin in Option 2a:

Eq. (35) $$I_{\text{sec}\,limit} > I_{sec} \times 115\%$$

$$I_{\text{sec}\,limit} > 7.477\ A \times 1.15$$

$$I_{\text{sec}\,limit} > 8.598\ A$$

Example Calculations: Option 2b

Option 2b represents a more complex calculation for synchronous generators applying a phase overcurrent (e.g., 50, 51, or 51V-R) relay:

Real Power output (P):

Eq. (36) $$P = GEN_{Synch_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (37) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base (MVA_{base}).

Real Power output (P):

Eq. (38) $$P_{pu} = \frac{P_{Synch_reported}}{MVA_{base}}$$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Example Calculations: Option 2b

Reactive Power output (Q):

Eq. (39) $$Q_{pu} = \frac{Q}{MVA_{base}}$$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Transformer impedance:

Eq. (40) $$X_{pu} = X_{GSU(old)} \times \frac{MVA_{base}}{MVA_{GSU}}$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Estimate initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (41) $$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times [V_{high-side}])}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.7°$$

Eq. (42)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

Example Calculations: Option 2b

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (43) $$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times \lceil V_{high-side} \rceil)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (44)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (45) $$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Example Calculations: Option 2b

Apparent power (S):

Eq. (46) $S = P_{Synch_reported} + jQ$

$S = 700.0\ MW + j1151.3\ Mvar$

$S = 1347.4 \angle 58.7°\ MVA$

Primary current (I_{pri}):

Eq. (47) $I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$

$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 21.90\ kV}$

$I_{pri} = 35553\ A$

Secondary current (I_{sec}):

Eq. (48) $I_{sec} = \frac{I_{pri}}{CT_{ratio}}$

$I_{sec} = \frac{35553\ A}{\frac{25000}{5}}$

$I_{sec} = 7.111\ A$

To satisfy the 115% margin in Option 2b:

Eq. (49) $I_{\mathrm{sec}\,limit} > I_{sec} \times 115\%$

$I_{\mathrm{sec}\,limit} > 7.111\ A \times 1.15$

$I_{\mathrm{sec}\,limit} > 8.178\ A$

Example Calculations: Option 2c

Option 2c represents a more involved, more precise setting of the overcurrent element for the phase overcurrent (e.g., 50, 51, or 51V-R) relay. This option requires determining maximum generator Reactive Power output during field-forcing and the corresponding generator bus voltage. Once these values are determined, the remainder of the calculation is the same as Options 2a and 2b.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a voltage-restrained phase overcurrent relay.

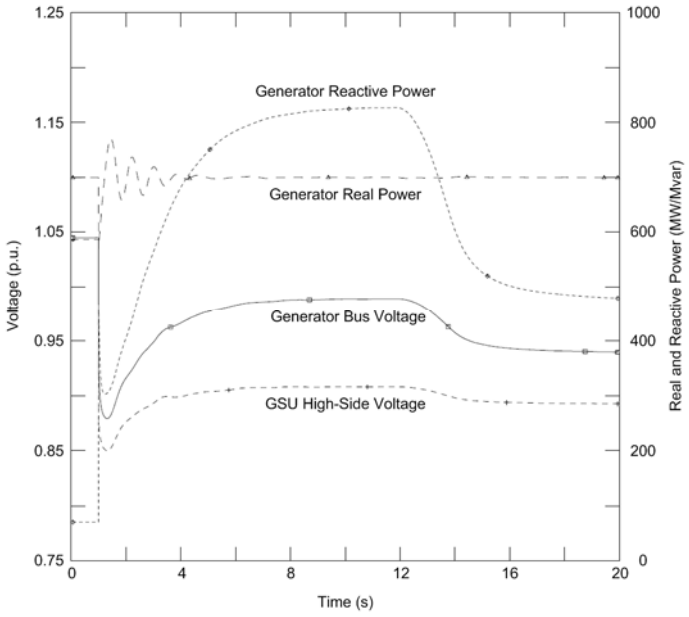
In this simulation the following values are derived:

$$Q = 827.4\ Mvar$$

$$V_{bus_simulated} = 0.989 \times V_{gen_nom} = 21.76\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{Synch_reported} = 700.0\ MW$$



Example Calculations: Option 2c

Apparent power (S):

Eq. (50) $S = P_{Synch_reported} + jQ$

$S = 700.0\ MW + j827.4\ Mvar$

$S = 1083.8 \angle 49.8°\ MVA$

Primary current (I_{pri}):

Eq. (51) $I_{pri} = \frac{S}{\sqrt{3} \times V_{bus_simulated}}$

$I_{pri} = \frac{1083.8\ MVA}{1.73 \times 21.76\ kV}$

$I_{pri} = 28790\ A$

Secondary current (I_{sec}):

Eq. (52) $I_{sec} = \frac{I_{pri}}{CT_{ratio}}$

$I_{sec} = \frac{28790\ A}{\frac{25000}{5}}$

$I_{sec} = 5.758\ A$

To satisfy the 115% margin in Option 2c:

Eq. (53) $I_{\text{sec}\,limit} > I_{sec} \times 115\%$

$I_{\text{sec}\,limit} > 5.758\ A \times 1.15$

$I_{\text{sec}\,limit} > 6.622\ A$

Example Calculations: Options 3 and 6

Option 3 represents the only calculation for synchronous generators applying a phase time overcurrent (e.g., 51V-C) relay (Enabled to operate as a function of voltage). Similarly, Option 6 uses the same calculation for asynchronous generators.

Example Calculations: Options 3 and 6

Options 3 and 6, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (54) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

The voltage setting shall be set less than 75% of the generator bus voltage:

Eq. (55) $$V_{setting} < V_{gen} \times 75\%$$

$$V_{setting} < 21.9\ kV\ \times 0.75$$

$$V_{setting} < 16.429\ kV$$

Example Calculations: Option 4

This represents the calculation for an asynchronous generator (including inverter-based installations) applying a phase distance relay (e.g., 21) directional toward the Transmission system.

Real Power output (P):

Eq. (56) $$P = GEN_{Asych_nameplate} \times pf$$

$$P = 40\ MVA\ \times 0.85$$

$$P = 34.0\ MW$$

Reactive Power output (Q):

Eq. (57) $$Q = GEN_{Async_nameplate} \times \sin(\cos^{-1}(pf))$$

$$Q = 40\ MVA \times \sin(\cos^{-1}(0.85))$$

$$Q = 21.1\ Mvar$$

Example Calculations: Option 4

Option 4, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (58) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (59) $$S = P + jQ$$

$$S = 34.0\ MW + j21.1\ Mvar$$

$$S = 40.0 \angle 31.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (60) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(21.9\ kV)^2}{40.0 \angle -31.8°\ MVA}$$

$$Z_{pri} = 11.99 \angle 31.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (61) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch_ratio}}{PT_{ratio}}$$

$$Z_{sec} = 11.99 \angle 31.8°\ \Omega \times \frac{\frac{5000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 11.99 \angle 31.8°\ \Omega \times 5$$

$$Z_{sec} = 59.95 \angle 31.8°\ \Omega$$

To satisfy the 130% margin in Option 4:

Eq. (62) $$Z_{\text{sec}\,limit} = \frac{Z_{sec}}{130\%}$$

Example Calculations: Option 4

$$Z_{\sec limit} = \frac{59.95\angle 31.8° \ \Omega}{1.30}$$

$$Z_{\sec limit} = 46.12\angle 31.8° \ \Omega$$

$$\theta_{transient\ load\ angle} = 31.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (63) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{46.12 \ \Omega}{\cos(85.0° - 31.8°)}$$

$$Z_{max} < \frac{46.12 \ \Omega}{0.599}$$

$$Z_{max} < \ 77.0\angle 85.0° \ \Omega$$

Example Calculations: Option 5a

This represents the calculation for three asynchronous generators applying a phase overcurrent (e.g., 50, 51, or 51V-R) relay. In this application it was assumed that 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (64) $$P = \ 3 \times GEN_{Asynch_nameplate} \times pf$$

$$P = 3 \times 40 \ MVA \ \times 0.85$$

$$P = 102.0 \ MW$$

Reactive Power output (Q):

Eq. (65) $$Q = MVAR_{static} + MVAR_{gen_static} + \left(3 \times GEN_{Asynch_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15 \ Mvar + 5 \ Mvar + (3 \times 40 \ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2 \ Mvar$$

Example Calculations: Option 5a

Option 5a, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (66) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (67) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (68) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473\angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (69) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch_ratio}}$$

$$I_{sec} = \frac{3473\angle -39.2°\ A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle -39.2°\ A$$

To satisfy the 130% margin in Option 5a:

Eq. (70) $$I_{\mathrm{sec}\,limit} > I_{sec} \times 130\%$$

$$I_{\mathrm{sec}\,limit} > 3.473\angle -39.2°\ A \times 1.30$$

Example Calculations: Option 5a

$$I_{\sec limit} > 4.52\angle -39.2° \; A$$

Example Calculations: Option 5b

Similarly to Option 5a, this example represents the calculation for three asynchronous generators applying a phase overcurrent (e.g., 50, 51, or 51V-R) relay. In this application it was assumed that 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (71) $$P = 3 \times GEN_{Asynch_nameplate} \times pf$$

$$P = 3 \times 40 \; MVA \times 0.85$$

$$P = 102.0 \; MW$$

Reactive Power output (Q):

Eq. (72) $$Q = MVAR_{static} + MVAR_{gen_static} + \left(3 \times GEN_{Asynch_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15 \; Mvar + 5 \; Mvar + (3 \times 40 \; MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2 \; Mvar$$

Option 5b, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (73) $$V_{gen} = 1.0 \; p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345 \; kV \times \left(\frac{22 \; kV}{346.5 \; kV}\right)$$

$$V_{gen} = 21.9 \; kV$$

Apparent power (S):

Eq. (74) $$S = P + jQ$$

$$S = 102.0 \; MW + j83.2 \; Mvar$$

$$S = 131.6\angle 39.2° \; MVA$$

Example Calculations: Option 5b

Primary current (I_{pri}):

Eq. (75) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473\angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (76) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch_ratio}}$$

$$I_{sec} = \frac{3473\angle -39.2°\ A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle -39.2°\ A$$

To satisfy Option 5b, the overcurrent element shall not infringe upon the resource capability (including the Mvar output of the resource and any static or dynamic reactive power devices) with worst case documented tolerances applied between the maximum resource capability and the overcurrent element (see Figure A).

Example Calculations: Options 7a and 10

These examples represent the calculation for a mixture of asynchronous (i.e., Option 10) and synchronous (i.e., Option 7a) generation (including inverter-based installations) applying a phase distance relay (e.g., 21) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Synchronous Generation (Option 7a)

Real Power output (P_{sync}):

Eq. (77) $$P_{Synch} = GEN_{Synch_nameplate} \times pf$$

$$P_{Synch} = 903\ MVA \times 0.85$$

$$P_{Synch} = 767.6\ MW$$

Example Calculations: Options 7a and 10

Reactive Power output (Q_{synch}):

Eq. (78) $$Q_{Synch} = 150\% \times P_{Synch}$$

$$Q_{Synch} = 1.50 \times 767.6\ MW$$

$$Q_{Synch} = 1151.3\ MW$$

Apparent power (S_{Synch}):

Eq. (79) $$S_{Synch} = P_{Synch_reported} + jQ_{Synch}$$

$$S_{Synch} = 700.0\ MW + j1151.3\ Mvar$$

Asynchronous Generation (Option 10)

Real Power output (P_{Asynch}):

Eq. (80) $$P_{Asynch} = 3 \times GEN_{Asynch_nameplate} \times pf$$

$$P_{Asynch} = 3 \times 40\ MVA \times 0.85$$

$$P_{Asynch} = 102.0\ MW$$

Reactive Power output (Q_{Asynch}):

Eq. (81) $$Q_{Asynch} = MVAR_{static} + MVAR_{gen_static} + \left(3 \times GEN_{Asynch_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q_{Asynch} = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2\ Mvar$$

Apparent power (S_{Asynch}):

Eq. (82) $$S_{Asynch} = P_{Asynch} + jQ_{Asynch}$$

$$S_{Asynch} = 102.0\ MW + j83.2\ Mvar$$

Example Calculations: Options 7a and 10

Options 7a and 10, Table 1 – Bus Voltage, Option 7a specifies 0.95 per unit of the high-side nominal voltage for the generator bus voltage and Option 10 specifies 1.0 per unit of the high-side nominal voltage for generator bus voltage. Due to the presence of the synchronous generator, the 0.95 per unit bus voltage will be used as (V_{gen}) as it results in the most conservative voltage:

Eq. (83) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S) accounted for 115% margin requirement for a synchronous generator and 130% margin requirement for an asynchronous generator:

Eq. (84) $$S = 115\% \times \left(P_{Synch_reported} + jQ_{Synch}\right) + 130\% \times \left(P_{Asynch} + jQ_{Asynch}\right)$$

$$S = 1.15 \times (700.0\ MW + j1151.3\ Mvar) + 1.30 \times (102.0\ MW + j83.2\ Mvar)$$

$$S = 1711.8 \angle 56.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (85) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(20.81\ kV)^2}{1711.8\angle -56.8°\ MVA}$$

$$Z_{pri} = 0.2527\angle 56.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (86) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.2527\angle 56.8°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.2527\angle 56.8°\ \Omega \times 25$$

$$Z_{sec} = 6.32\angle 56.8°\ \Omega$$

Example Calculations: Options 7a and 10

No additional margin is needed because the synchronous apparent power has been multiplied by 1.15 (115%) and the asynchronous apparent power has been multiplied by 1.30 (130%) in Equation 84 to satisfy the margin requirements in Options 7a and 10.

Eq. (87) $$Z_{\text{sec }limit} = \frac{Z_{sec}}{100\%}$$

$$Z_{\text{sec }limit} = \frac{6.32 \angle 56.8° \, \Omega}{1.00}$$

$$Z_{\text{sec }limit} = 6.32 \angle 56.8° \, \Omega$$

$$\theta_{transient\ load\ angle} = 56.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (88) $$Z_{max} < \frac{|Z_{\text{sec }limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{6.32 \, \Omega}{\cos(85.0° - 56.8°)}$$

$$Z_{max} < \frac{6.32 \, \Omega}{0.881}$$

$$Z_{max} < 7.17 \angle 85.0° \, \Omega$$

Example Calculations: Options 8a and 9a

Options 8a and 9a represents the simplest calculation for synchronous generators applying a phase overcurrent (e.g., 50, 51, or 67) relay. The following uses the $GEN_{Synch_nameplate}$ value to represent an "aggregate" value to illustrate the option:

Real Power output (P):

Eq. (89) $$P = GEN_{Synch_nameplate} \times pf$$

$$P = 903 \, MVA \times 0.85$$

$$P = 767.6 \, MW$$

Example Calculations: Options 8a and 9a

Reactive Power output (Q):

Eq. (90) $Q = 150\% \times P$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Options 8a and 9a, Table 1 – Bus Voltage, calls for a generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer generator bus voltage (V_{gen}):

Eq. (91) $V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (92) $S = P_{Synch_reported} + jQ$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4 \angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (93) $I_{pri} = \frac{S}{\sqrt{3} \times V_{gen}}$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 20.81\ kV}$$

$$I_{pri} = 37383\ A$$

Secondary current (I_{sec}):

Eq. (94) $I_{sec} = \frac{I_{pri}}{CT_{ratio}}$

Example Calculations: Options 8a and 9a

$$I_{sec} = \frac{37383\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.477\ A$$

To satisfy the 115% margin in Options 8a and 9a:

Eq. (95) $$I_{\text{sec}\,limit} > I_{sec} \times 115\%$$

$$I_{\text{sec}\,limit} > 7.477\ A \times 1.15$$

$$I_{\text{sec}\,limit} > 8.598\ A$$

Example Calculations: Options 8b and 9b

Options 8b and 9b represents a more precise calculation for synchronous generators applying a phase overcurrent (e.g., 50, 51, or 67) relay. The following uses the $GEN_{Synch_nameplate}$ value to represent an "aggregate" value to illustrate the option:

Real Power output (P):

Eq. (96) $$P = GEN_{Synch_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (97) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base (GSU Transformer MVA_{base}).

Real Power output (P):

Eq. (98) $$P_{pu} = \frac{P_{Synch_reported}}{MVA_{base}}$$

Example Calculations: Options 8b and 9b

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (99) $$Q_{pu} = \frac{Q}{MVA_{base}}$$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Transformer impedance:

Eq. (100) $$X_{pu} = X_{GSU(old)} \times \frac{MVA_{base}}{MVA_{GSU}}$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Estimate initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (101) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times \lceil V_{high-side} \rceil\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

Eq. (102)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

Example Calculations: Options 8b and 9b

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (103) $$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times [V_{high-side}])}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (104)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (105) $$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Example Calculations: Options 8b and 9b

Apparent power (S):

Eq. (106) $S = P_{Synch_reported} + jQ$

$S = 700.0\ MW + j1151.3\ Mvar$

$S = 1347.4 \angle 58.7°\ MVA$

Primary current (I_{pri}):

Eq. (107) $I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$

$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 21.90\ kV}$

$I_{pri} = 35553\ A$

Secondary current (I_{sec}):

Eq. (108) $I_{sec} = \frac{I_{pri}}{CT_{ratio}}$

$I_{sec} = \frac{35553\ A}{\frac{25000}{5}}$

$I_{sec} = 7.111\ A$

To satisfy the 115% margin in Options 8b and 9b:

Eq. (109) $I_{\mathrm{sec}\,limit} > I_{sec} \times 115\%$

$I_{\mathrm{sec}\,limit} > 7.111\ A \times 1.15$

$I_{\mathrm{sec}\,limit} > 8.178\ A$

Example Calculations: Options 8a, 9a, 11, and 12

This example represents the calculation for a mixture of asynchronous and synchronous generators applying a phase overcurrent (e.g., 50, 51, or 67) relays. In this application it was assumed 20 Mvar of total static compensation was added. The current transformers (CT) are located on the low-side of the GSU transformer.

Synchronous Generation (Options 8a and 9a)

Real Power output (P_{Synch}):

Eq. (110) $$P_{Synch} = GEN_{Synch_nameplate} \times pf$$

$$P_{Synch} = 903\ MVA \times .85$$

$$P_{Synch} = 767.6\ MW$$

Reactive Power output (Q_{Synch}):

Eq. (111) $$Q_{Synch} = 150\% \times P_{Synch}$$

$$Q_{Synch} = 1.50 \times 767.6\ MW$$

$$Q_{Synch} = 1151.3\ Mvar$$

Apparent power (S_{Synch}):

Eq. (112) $$S_{Synch} = P_{Synch_reported} + jQ_{Synch}$$

$$S_{Synch} = 700.0\ MW + j1151.3\ Mvar$$

$$S_{Synch} = 1347.4\ \angle 58.7°\ MVA$$

Option 8a, Table 1 – Bus Voltage calls for a 0.95 per unit of the high-side nominal voltage as a basis for generator bus voltage (V_{gen}):

Eq. (113) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Example Calculations: Options 8a, 9a, 11, and 12

Primary current ($I_{pri\text{-}sync}$):

Eq. (114) $$I_{pri-sync} = \frac{115\% \times S^{*}_{Synch}}{\sqrt{3} \times V_{gen}}$$

$$I_{pri-sync} = \frac{1.15 \times (1347.4 \angle -58.7° \; MVA)}{1.73 \times 20.81 \; kV}$$

$$I_{pri-sync} = 43061 \angle -58.7° \; A$$

Asynchronous Generation (Options 11 and 12)

Real Power output (P_{Asynch}):

Eq. (115) $$P_{Asynch} = \; 3 \times GEN_{Asynch_nameplate} \times pf$$

$$P_{Asynch} = 3 \times 40 \; MVA \; \times 0.85$$

$$P_{Asynch} = 102.0 \; MW$$

Reactive Power output (Q_{Asynch}):

Eq. (116) $$Q_{Asynch} = MVAR_{static} + MVAR_{gen_static} + GEN_{Asynch_nameplate} \times \sin(\cos^{-1}(pf))$$

$$Q_{Asynch} = 15 \; Mvar + 5 \; Mvar + (3 \times 40 \; MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2 \; Mvar$$

Option 11, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}), however due to the presence of synchronous generator 0.95 per unit bus voltage will be used:

Eq. (117) $$V_{gen} = 0.95 \; p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345 \; kV \times \left(\frac{22 \; kV}{346.5 \; kV}\right)$$

$$V_{gen} \; = \; 20.81 \; kV$$

Apparent power (S_{Asynch}):

Eq. (118) $$S_{Asynch} = 130\% \; \times (P_{Asynch} + jQ_{Asynch})$$

$$S_{Asynch} = 1.30 \; \times (102.0 \; MW + j83.2 \; Mvar)$$

Example Calculations: Options 8a, 9a, 11, and 12

$$S_{Asynch} = 171.1 \angle 39.2° \; MVA$$

Primary current ($I_{pri\text{-}async}$):

Eq. (119) $$I_{pri-async} = \frac{S_{Asych}}{\sqrt{3} \times V_{gen}}$$

$$I_{pri-async} = \frac{171.1 \angle -39.2° \; MVA}{1.73 \; \times 20.81 \; kV}$$

$$I_{pri-async} = 4755 \angle -39.2° \; A$$

Secondary current (I_{sec}):

Eq. (120) $$I_{sec} = \frac{I_{pri-sync}}{CT_{ratio}} + \frac{I_{pri-async}}{CT_{ratio}}$$

$$I_{sec} = \frac{43061 \angle -58.7° \; A}{\frac{25000}{5}} + \frac{4755 \angle -39.2° \; A}{\frac{25000}{5}}$$

$$I_{sec} = 9.514 \angle -56.8° \; A$$

No additional margin is needed because the synchronous apparent power has been multiplied by 1.15 (115%) in Equation 114 and the asynchronous apparent power has been multiplied by 1.30 (130%) in Equation 118.

Eq. (121) $$I_{\text{sec}\,limit} > I_{sec} \times 100\%$$

$$I_{\text{sec}\,limit} > 9.514 \angle -56.8° \; A \times 1.00$$

$$I_{\text{sec}\,limit} > 9.514 \angle -56.8° \; A$$

Example Calculations: Options 8c and 9c

This example uses Option 15b as a simulation example for a synchronous generator applying a phase overcurrent relay (e.g., 50, 51, or 67). In this application the same synchronous generator is modeled as for Options 1c, 2c, and 7c. The CTs are located on the low-side of the GSU transformer.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer, during field-forcing, is used since this value will correspond to the highest current. The corresponding

Example Calculations: Options 8c and 9c

generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.

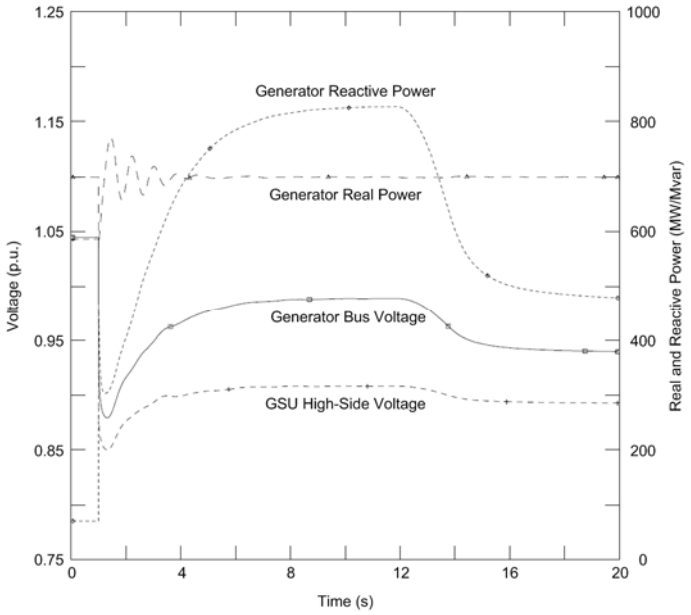
In this simulation the following values are derived:

$$Q = 827.4\ Mvar$$

$$V_{bus_simulated} = 0.989 \times V_{gen} = 21.76\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$



Apparent power (S):

Eq. (122) $$S = P_{Synch_reported} + jQ$$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°$$

Example Calculations: Options 8c and 9c

Primary current (I_{pri}):

Eq. (123) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{bus_simulated}}$$

$$I_{pri} = \frac{1083.8\ MVA}{1.73 \times 21.76\ kV}$$

$$I_{pri} = 28790\ A$$

Secondary current (I_{sec}):

Eq. (124) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{28790\ A}{\frac{25000}{5}}$$

$$I_{sec} = 5.758\ A$$

To satisfy the 115% margin in Options 8c and 9c:

Eq. (125) $$I_{\mathrm{sec}\,limit} > I_{sec} \times 115\%$$

$$I_{\mathrm{sec}\,limit} > 5.758\ A \times 1.15$$

$$I_{\mathrm{sec}\,limit} > 6.622\ A$$

Example Calculations: Option10

This example represents the calculation for three asynchronous generators (including inverter-based installations) applying a phase distance relay (e.g., 21) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (126) $$P = 3 \times GEN_{Asych_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

Example Calculations: Option10

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (127) $$Q = MVAR_{static} + MVAR_{gen_static} + \left(3 \times GEN_{Asynch_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Option 10, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (128) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (129) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (130) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(21.9\ kV)^2}{131.6\angle -39.2°\ MVA}$$

$$Z_{pri} = 3.644\ \angle 39.2°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (131) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch_ratio}}{PT_{ratio}}$$

Example Calculations: Option10

$$Z_{sec} = 3.644 \angle 39.2° \, \Omega \times \frac{\frac{5000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 3.644 \angle 39.2° \, \Omega \times 5$$

$$Z_{sec} = 18.22 \angle 39.2° \, \Omega$$

To satisfy the 130% margin in Option 10:

Eq. (132) $$Z_{\text{sec}\,limit} = \frac{Z_{sec}}{130\%}$$

$$Z_{\text{sec}\,limit} = \frac{18.22 \angle 39.2° \, \Omega}{1.30}$$

$$Z_{\text{sec}\,limit} = 14.02 \angle 39.2° \, \Omega$$

$$\theta_{transient\ load\ angle} = 39.2°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (133) $$Z_{max} < \frac{|Z_{\text{sec}\,limit}|}{\cos\left(\theta_{MTA} - \theta_{transient\ load\ angle}\right)}$$

$$Z_{max} < \frac{14.02 \, \Omega}{\cos(85.0° - 39.2°)}$$

$$Z_{max} < \frac{14.02 \, \Omega}{0.6972}$$

$$Z_{max} < \ 20.11 \angle 85.0° \, \Omega$$

Example Calculations: Options 11 and 12

Option 11 represents the calculation for a GSU transformer applying a phase overcurrent (e.g., 50 or 51) relay connected to three asynchronous generators. Similarly, these calculations can be applied to Option 12 for a phase directional overcurrent relay (e.g., 67) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Example Calculations: Options 11 and 12

Real Power output (P):

Eq. (134) $$P = 3 \times GEN_{Asynch_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (135) $$Q = MVAR_{static} + MVAR_{gen_static} + \left(3 \times GEN_{Asynch_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Options 11 and 12, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (136) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (137) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6 \angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (138) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{131.6 \angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473 \angle -39.2°\ A$$

Example Calculations: Options 11 and 12

Secondary current (I_{sec}):

Eq. (139) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch_ratio}}$$

$$I_{sec} = \frac{3473\angle -39.2°\ A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle -39.2°\ A$$

To satisfy the 130% margin in Options 11 and12:

Eq. (140) $$I_{\text{sec}\,limit} > I_{sec} \times 130\%$$

$$I_{\text{sec}\,limit} > 3.473\angle -39.2°\ A \times 1.30$$

$$I_{\text{sec}\,limit} > 4.515\angle -39.2°\ A$$

Example Calculations: Options 13a and 13b

Option 13a for the UAT assumes the maximum nameplate rating of the winding is utilized for the purposes of the calculations and the appropriate voltage. Similarly, Option 13b uses the measured current while operating at the maximum gross MW capability reported to the Transmission Planner.

Primary current (I_{pri}):

Eq. (141) $$I_{pri} = \frac{UAT_{nameplate}}{\sqrt{3} \times V_{UAT}}$$

$$I_{pri} = \frac{60\ MVA}{1.73 \times 13.8\ kV}$$

$$I_{pri} = 2510.2\ A$$

Secondary current (I_{sec}):

Eq. (142) $$I_{sec} = \frac{I_{pri}}{CT_{UAT}}$$

Example Calculations: Options 13a and 13b

$$I_{sec} = \frac{2510.2\ A}{\frac{5000}{5}}$$

$$I_{sec} = 2.51\ \text{A}$$

To satisfy the 150% margin in Options 13a:

Eq. (143) $$I_{\text{sec}\,limit} > I_{sec} \times 150\%$$

$$I_{\text{sec}\,limit} > 2.51\ A \times 1.50$$

$$I_{\text{sec}\,limit} > 3.77\ A$$

Example Calculations: Option 14a

Option 14a represents the calculation for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that connected to synchronous generation. In this example, the Element is protected by a phase distance (e.g., 21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU transformer.

Real Power output (P):

Eq. (144) $$P = GEN_{Synch_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (145) $$Q = 120\% \times P$$

$$Q = 1.20 \times 767.6\ MW$$

$$Q = 921.1\ Mvar$$

Option 14a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the line nominal voltage for the GSU transformer voltage (V_{nom}):

Eq. (146) $$V_{bus} = 0.85\ p.u. \times V_{nom}$$

Example Calculations: Option 14a

$$V_{gen} = 0.85 \times 345\ kV$$

$$V_{gen} = 293.25\ kV$$

Apparent power (S):

Eq. (147) $$S = P_{Synch_reported} + jQ$$

$$S = 700.0\ MW + j921.1\ Mvar$$

$$S = 1157.0\angle 52.77°\ MVA$$

$$\theta_{transient\ load\ angle} = 52.77°$$

Primary impedance (Z_{pri}):

Eq. (148) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(293.25\ kV)^2}{1157.0\angle -52.77°\ MVA}$$

$$Z_{pri} = 74.335\angle 52.77°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (149) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio_hv}}{PT_{ratio_hv}}$$

$$Z_{sec} = 74.335\angle 52.77°\ \Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 74.335\angle 52.77°\ \Omega \times 0.2$$

$$Z_{sec} = 14.867\angle 52.77°\ \Omega$$

To satisfy the 115% margin in Option 14a:

Eq. (150) $$Z_{\text{sec}\,limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\text{sec}\,limit} = \frac{14.867\angle 52.77°\ \Omega}{1.15}$$

Example Calculations: Option 14a

$$Z_{\sec limit} = 12.928\angle 52.77° \ \Omega$$

$$\theta_{transient\ load\ angle} = 52.77°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (151) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos\left(\theta_{MTA} - \theta_{transient\ load\ angle}\right)}$$

$$Z_{max} < \frac{12.928\ \Omega}{\cos(85.0° - 52.77°)}$$

$$Z_{max} < \frac{12.928\ \Omega}{0.846}$$

$$Z_{max} < \ 15.283\angle 85.0° \ \Omega$$

Example Calculations: Option 14b

Option 14b represents the simulation for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant connected to synchronous generation. In this example, the Element is protected by a phase distance (e.g., 21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU transformer.

The Reactive Power flow and high-side bus voltage are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding high-side bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.

In this simulation the following values are derived:

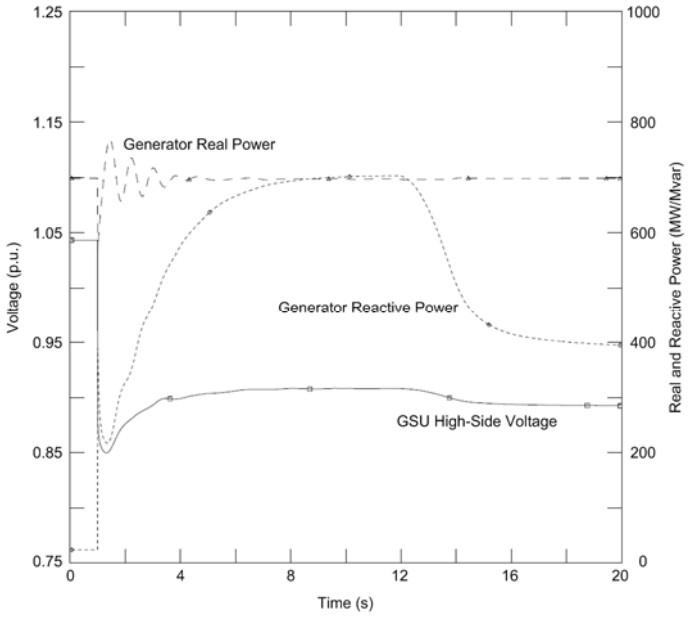
$$Q = 703.6\ Mvar$$

$$V_{bus_simulated} = 0.908 \times V_{nom} = 313.3\ kV$$

Example Calculations: Option 14b

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$



Apparent power (S):

Eq. (152) $S = P_{Synch_reported} + jQ$

$$S = 700.0\ MW + j703.6\ Mvar$$

$$S = 992.5\angle 45.1°\ MVA$$

$$\theta_{transient\ load\ angle} = 45.1°$$

Primary impedance (Z_{pri}):

Eq. (153) $$Z_{pri} = \frac{V_{bus_simulated}^2}{S^*}$$

$$Z_{pri} = \frac{(313.3\ kV)^2}{992.5\angle -45.1°\ MVA}$$

$$Z_{pri} = 98.90\angle 45.1°\ \Omega$$

Example Calculations: Option 14b

Secondary impedance (Z_{sec}):

Eq. (154) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio_hv}}{PT_{ratio_hv}}$$

$$Z_{sec} = 98.90\angle 45.1° \, \Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 98.90\angle 45.1° \, \Omega \times 0.2$$

$$Z_{sec} = 19.78\angle 45.1° \, \Omega$$

To satisfy the 115% margin in Option 14b:

Eq. (155) $$Z_{\text{sec}\,limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\text{sec}\,limit} = \frac{19.78\angle 45.1° \, \Omega}{1.15}$$

$$Z_{\text{sec}\,limit} = 17.20\angle 45.1° \, \Omega$$

$$\theta_{transient\ load\ angle} = 45.1°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (156) $$Z_{max} < \frac{|Z_{\text{sec}\,limit}|}{\cos\left(\theta_{MTA} - \theta_{transient\ load\ angle}\right)}$$

$$Z_{max} < \frac{17.20 \, \Omega}{\cos(85.0° - 45.1°)}$$

$$Z_{max} < \frac{17.20 \, \Omega}{0.767}$$

$$Z_{max} < \ 22.42\angle 85.0° \, \Omega$$

Example Calculations: Options 15a and 16a

Options 15a and 16a represent the calculation for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant connected to synchronous generation. Option 15a represents applying a phase time overcurrent relay (e.g., 51) and/or phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer and remote end of the line. Option 16a represents applying a phase directional instantaneous overcurrent supervisory element (e.g., 67) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system installed on the high-side of the GSU and at the remote end of the line and/or a phase time directional overcurrent relay (e.g., 67) directional toward the Transmission system installed on the high-side of the GSU transformer and remote end of the line.

Example calculations are provided for the case, where potential transformers (PT) and current transformers (CT) are located at the high-side of the GSU transformer. The 0.85 per unit of the line nominal voltage at the relay location will be at the high-side of the GSU transformer. Example calculations are also provided for the case where PTs and CTs are located at the remote end of the line and the 0.85 per unit of the line nominal voltage will be at the remote bus location.

Calculations at the high-side of the GSU transformer.

Real Power output (P):

Eq. (157) $$P = GEN_{Synch_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (158) $$Q = 120\% \times P$$

$$Q = 1.20 \times 767.6\ MW$$

$$Q = 921.12\ Mvar$$

Option 15a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the line nominal voltage:

Eq. (159) $$V_{bus} = 0.85\ p.u. \times V_{nom}$$

$$V_{bus} = 0.85 \times 345\ kV$$

Example Calculations: Options 15a and 16a

$$V_{bus} = 293.25\ kV$$

Apparent power (S):

Eq. (160) $$S = P_{Synch_reported} + jQ$$

$$S = 700.0\ MW + j921.12\ Mvar$$

$$S = 1157\angle 52.8°\ MVA$$

Primary current (I_{pri}):

Eq. (161) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1157\angle -52.8°\ MVA}{1.73 \times 293.25\ kV}$$

$$I_{pri} = 2280.6\angle -52.8°\ A$$

Secondary current (I_{sec}):

Eq. (162) $$I_{sec} = \frac{I_{pri}}{CT_{ratio_hv}}$$

$$I_{sec} = \frac{2280.6\angle -52.8°\ A}{\frac{2000}{5}}$$

$$I_{sec} = 5.701 \angle -52.8°\ A$$

To satisfy the 115% margin in Options 15a and 16a:

Eq. (163) $$I_{\text{sec}\,limit} > I_{sec} \times 115\%$$

$$I_{\text{sec}\,limit} > 5.701 \angle -52.8°\ A \times 1.15$$

$$I_{\text{sec}\,limit} > 6.56 \angle -52.8°\ A$$

Calculations at the remote end of the line from the plant.

Real Power output (P):

Eq. (164) $$P = GEN_{Synch_nameplate} \times pf$$

Example Calculations: Options 15a and 16a

$$P = 903\ MVA\ \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (165) $$Q = 120\% \times P$$

$$Q = 1.20 \times 767.6\ MW$$

$$Q = 921.12\ Mvar$$

Option 15a and 16a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the line nominal voltage at the relay location, in this example the relay location is at the remote substation bus.

Eq. (166) $$V_{bus_remote_substation} = 0.85\ p.u. \times V_{nom}$$

$$V_{bus_remote_substation} = 0.85 \times 345\ kV$$

$$V_{bus_remote_substation} = 293.25\ kV$$

Apparent power (S):

Eq. (167) $$S = P_{Synch_reported} + jQ$$

$$S = 700.0\ MW + j921.12\ Mvar$$

$$S = 1157\angle 52.8°\ MVA$$

Primary current (I_{pri}):

Eq. (168) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus_remote_substation}}$$

$$I_{pri} = \frac{1157\angle -52.8°\ MVA}{1.73 \times 293.25\ kV}$$

$$I_{pri} = 2280.6\angle -52.8°\ A$$

Secondary current (I_{sec}):

Eq. (169) $$I_{sec} = \frac{I_{pri}}{CT_{CT_{ratio_remote_bus}}}$$

Example Calculations: Options 15a and 16a

$$I_{sec} = \frac{2280.6\angle -52.8° \; A}{\frac{2000}{5}}$$

$$I_{sec} = 5.701 \angle -52.8° \; A$$

To satisfy the 115% margin in Options 15a and 16a:

Eq. (170) $$I_{\text{sec}\,limit} > I_{sec} \times 115\%$$

$$I_{\text{sec}\,limit} > 5.701 \angle -52.8° \; A \times 1.15$$

$$I_{\text{sec}\,limit} > 6.56 \angle -52.8° \; A$$

Example Calculations: Options 15b and 16b

Options 15b and 16b represent the calculation for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant connected to synchronous generation. Option 15b represents applying a phase time overcurrent relay (e.g., 51) and/or phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer and remote end of the line. Option 16b represents applying a phase directional instantaneous overcurrent supervisory element (e.g., 67) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system installed on the high-side of the GSU and at the remote end of the line and/or a phase directional time overcurrent relay (e.g., 67) directional toward the Transmission system installed on the high-side of the GSU and remote end of the line.

Example calculations are provided for the case, where PTs and CTs are located at the remote end of the line from the plant. The 0.85 per unit of the line nominal voltage is applied at the remote end of the line.

The Reactive Power flow and high-side bus voltage are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding high-side bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.

Example Calculations: Options 15b and 16b

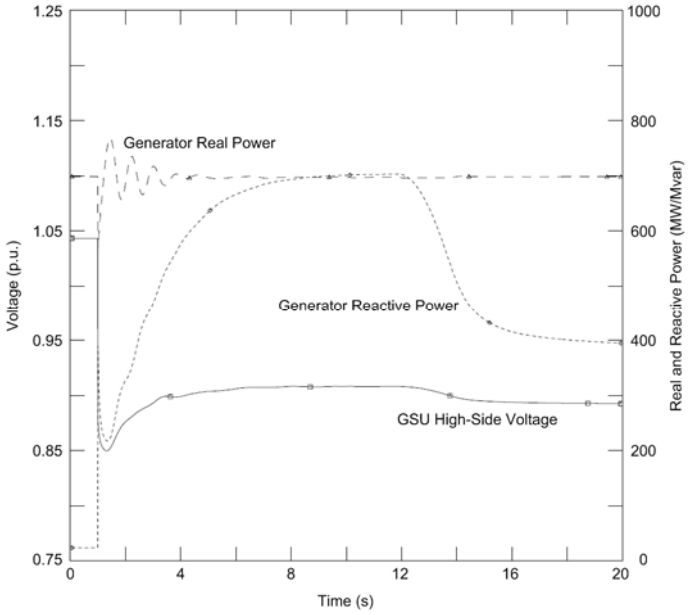
In this simulation the following values are derived:

$$Q = 703.6\ Mvar$$

$$V_{bus_simulated} = 0.908 \times V_{nom} = 313.3\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$



Apparent power (S):

Eq. (171) $$S = P_{Synch_reported} + jQ$$

$$S = 700.0\ MW + j703.6\ Mvar$$

$$S = 992.5\angle 45.1°\ MVA$$

Primary current (I_{pri}):

Eq. (172) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus_simulated}}$$

$$I_{pri} = \frac{992.5\angle -45.1°\ MVA}{1.73 \times 313.3\ kV}$$

Example Calculations: Options 15b and 16b

$$I_{pri} = 1831.2\angle -45.1° \, A$$

Secondary current (I_{sec}):

Eq. (173) $$I_{sec} = \frac{I_{pri}}{CT_{ratio_hv}}$$

$$I_{sec} = \frac{1831.2\angle -45.1° \, A}{\frac{2000}{5}}$$

$$I_{sec} = 4.578 \angle -45.1° \, A$$

To satisfy the 115% margin in Options 15b and 16b:

Eq. (174) $$I_{\text{sec}\,limit} > I_{sec} \times 115\%$$

$$I_{\text{sec}\,limit} > 4.578 \angle -45.1° \, A \times 1.15$$

$$I_{\text{sec}\,limit} > 5.265 \angle -45.1° \, A$$

Example Calculations: Option 17

Option 17 represents the calculation for Elements that connect a GSU transformer for three asynchronous generators to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that is applying a phase distance relay (e.g., 21) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (175) $$P_{Asynch} = 3 \times GEN_{Asynch_nameplate} \times pf$$

$$P_{Asynch} = 3 \times 40 \, MVA \times 0.85$$

$$P_{Asynch} = 102.0 \, MW$$

Reactive Power output (Q):

Eq. (176) $$Q_{Asynch} = MVAR_{static} + MVAR_{gen_static} + \left(3 \times GEN_{Asynch_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

Example Calculations: Option 17

$$Q_{Asynch} = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2\ Mvar$$

Option 17, Table 1 – Bus Voltage, calls for a 1.0 per unit of the line nominal voltage for the bus voltage (V_{bus}):

Eq. (177) $$V_{bus} = 1.0\ p.u. \times V_{nom}$$

$$V_{gen} = 1.0 \times 345\ kV$$

$$V_{gen} = 345.0\ kV$$

Apparent power (S):

Eq. (178) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (179) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(345.0\ kV)^2}{131.6\angle -39.2°\ MVA}$$

$$Z_{pri} = 904.4\angle 39.2°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (180) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch_ratio_hv}}{PT_{ratio_hv}}$$

$$Z_{sec} = 904.4\angle 39.2°\ \Omega \times \frac{\frac{300}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 904.4\angle 39.2°\ \Omega \times 0.03$$

$$Z_{sec} = 27.13\angle 39.2°\ \Omega$$

Example Calculations: Option 17

To satisfy the 130% margin in Option 17:

Eq. (181) $$Z_{\text{sec }limit} = \frac{Z_{sec}}{130\%}$$

$$Z_{\text{sec }limit} = \frac{27.13\angle 39.2°\ \Omega}{1.30}$$

$$Z_{\text{sec }limit} = 20.869\angle 39.2°\ \Omega$$

$$\theta_{transient\ load\ angle} = 39.2°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, and then the maximum allowable impedance reach is:

Eq. (182) $$Z_{max} < \frac{|Z_{\text{sec }limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{20.869\ \Omega}{\cos(85.0° - 39.2°)}$$

$$Z_{max} < \frac{20.869\ \Omega}{0.697}$$

$$Z_{max} < 29.941\angle 85.0°\ \Omega$$

Example Calculations: Options 18 and 19

Option 18 represents the calculation for relays on Elements that connect a GSU transformer for three asynchronous generators to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Option 18 represents applying a phase time overcurrent (e.g., 51) and/or phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer and remote end of the line.

Similarly, Option 19 may also be applied here for the phase directional overcurrent relays (e.g., 67) directional toward the Transmission system for Elements that connect a GSU transformer and remote end of the line to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. In this application it was assumed 20 Mvar of total static compensation was added.

Example Calculations: Options 18 and 19

Real Power output (P):

Eq. (183) $$P = 3 \times GEN_{Asych_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (184) $$Q = MVAR_{static} + MVAR_{gen_static} + \left(3 \times GEN_{Asynch_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Options 18 and 19, Table 1 – Bus Voltage, calls for a 1.0 per unit of the line nominal voltage (V_{bus}):

Eq. (185) $$V_{nom} = 1.0\ p.u. \times V_{nom}$$

$$V_{bus} = 1.0 \times 345\ kV$$

$$V_{bus} = 345\ kV$$

Apparent power (S):

Eq. (186) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6 \angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (187) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{131.6 \angle -39.2°\ MVA}{1.73 \times 345\ kV}$$

$$I_{pri} = 220.5 \angle -39.2° A$$

Example Calculations: Options 18 and 19

Secondary current (I_{sec}):

Eq. (188) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch_ratio_hv}}$$

$$I_{sec} = \frac{220.5\angle -39.2° \, A}{\frac{300}{5}}$$

$$I_{sec} = 3.675\angle -39.2° \, A$$

To satisfy the 130% margin in Options 18 and 19:

Eq. (189) $$I_{\mathrm{sec}\,limit} > I_{sec} \times 130\%$$

$$I_{\mathrm{sec}\,limit} > 3.675\angle -39.2° \, A \times 1.30$$

$$I_{\mathrm{sec}\,limit} > 4.778\angle -39.2° \, A$$

End of calculations

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

Requirement R1 is a risk-based requirement that requires the responsible entity to be aware of each protective relay subject to the standard and applies an appropriate setting based on its calculations or simulation for the conditions established in Attachment 1.

The criteria established in Attachment 1 represent short-duration conditions during which generation Facilities are capable of providing system reactive resources, and for which generation Facilities have been historically recorded to disconnect, causing events to become more severe.

The term, “while maintaining reliable fault protection” in Requirement R1 describes that the responsible entity is to comply with this standard while achieving their desired protection goals. Refer to the Guidelines and Technical Basis, Introduction, for more information.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2016-04 – Modifications to PRC-025-1

Requested Approvals

- PRC-025-2 – Generator Relay Loadability

Requested Retirements

- PRC-025-1 – Generator Relay Loadability

Prerequisite Approvals

- None.

Applicable Entities*

- Generator Owner
- Transmission Owner
- Distribution Provider

*See the proposed standard for detailed applicability for functional entities and Facilities.

Terms in the NERC Glossary of Terms

- No definitions are proposed as a part of this standard.

Background

The Reliability Standard PRC-025-1 went into effect in the United States on October 1, 2014 under a phased implementation plan based on two time frames. The first timeframe was provided to the Generator Owner, Transmission Owner, or Distribution Provider to apply settings to its existing load-responsive protective relays that are capable of meeting the standard while maintaining reliable fault protection. The second and extended timeframe was provided to the Generator Owner, Transmission Owner, or Distribution Provider that determined its existing load-responsive protective relays require replacement or removal. The PRC-025-1 standard drafting team recognized that it may be necessary to replace a legacy load-responsive protective relay with a modern advanced-technology relay that can be set using functions such as load encroachment or that removal of the load-responsive protective relay is the best alternative to satisfy the entity's protection criteria and meet the requirements of PRC-025-1.

General Considerations

The PRC-025-2 standard drafting team considered the scope of the proposed revisions and the timing for regulatory approvals with respect to the version one enforcement dates. The first U.S. enforcement date of October 1, 2019 applies to load-responsive protective relays where the applicable entity will be making a setting change to meet the setting criteria of the standard while maintaining reliable fault protection. The second U.S. enforcement date of October 1, 2021 applies to load-responsive protective relays where

the applicable entity will be removing or replacing the relay to meet the setting criteria of the standard while maintaining reliable fault protection.

The PRC-025-2 Implementation Plan reflects consideration of the following:

- The proposed Option 5b reduces the implementation burden to the applicable entities.
- The proposed revisions to Options 14a, 14b, 15a, 15b, 16a, 16b, 17, 18, and 19 may give reason for entities to re-evaluate their settings for load-responsive protective relays.
- A few proposed Option(s) now include the 50 element.

Effective Date

PRC-025-2

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

Effective Date and Phased-In Compliance Dates

Load-responsive protective relays subject to the standard

Each Generator Owner, Transmission Owner, or Distribution Provider shall not be required to comply with Requirement R1 until the following dates after the effective date of Reliability Standard PRC-025-2:

Requirement	Applicability	Implementation Date
R1	Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-2 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection.	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 12 months after the effective date of Reliability Standard PRC-025-2
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 36 months after the effective date of Reliability Standard PRC-025-2

Load-responsive protective relays which become applicable to the standard

Each Generator Owner, Transmission Owner, or Distribution Provider that owns load-responsive protective relays that become applicable to this standard, not because of the actions of itself including but

not limited to changes in NERC Registration Criteria or Bulk Electric System (BES) definition, shall not be required to comply with Requirement R1 until the following dates:

Requirement	Applicability	Implementation Date
R1	Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-2 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection.	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 60 months beyond the date the load-responsive protective relays become applicable to the standard
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 84 months beyond the date the load-responsive protective relays become applicable to the standard

Retirement Date

- PRC-025-1
  Reliability Standard PRC-025-1 shall be retired immediately prior to the effective date of PRC-025-2 in the particular jurisdiction in which the revised standard is becoming effective.

Phased-In Retirement

- None.

Implementation Plan for Definitions

- No definitions are proposed as a part of this standard.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Violation Risk Factor and Violation Severity Level Justifications

PRC-025-2 – Generator Relay Loadability

Violation Risk Factor and Violation Severity Level Justifications

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in: PRC-025 – Generator Relay Loadability. Note that no Requirement, Measure, or VRF/VSL changes have been made in this proposed PRC-025-2 Reliability Standard.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

The Reliability Coordination Standard Drafting Team (SDT) applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSL for the requirements under this project.

NERC Criteria – Violation Risk Factors

High Risk Requirement

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

Medium Risk Requirement

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

restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

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

FERC Violation Risk Factor Guidelines

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

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

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders

[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").
[2] Id. at footnote 15.

- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline 2 – Consistency within a Reliability Standard

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

Guideline 3 – Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline 4 – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline 5 – Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria – Violation Severity Levels

Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance, and may have only one, two, or three VSLs.

Violation severity levels should be based on the guidelines shown in the table below:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC Order of Violation Severity Levels

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

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

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

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

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

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

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

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

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

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

VRF and VSL Justifications

VRF Justifications – PRC-025-2, R1	
Proposed VRF	**High**
NERC VRF Discussion	A Violation Risk Factor of High is consistent with the NERC VRF definition. Failure by an entity to apply load-responsive protective relay settings in accordance with PRC-025-2, Attachment 1; Relay Settings, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. The unnecessary tripping of protective relays on generators has often been determined to have expanded the scope and/or extended the duration of disturbances of the past 25 years. This was also noted to be a serious issue in the August 2003 “blackout” in the northeastern North American continent.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis noted that generators tripped for the conditions being addressed by this standard, increasing the severity of the blackout.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: Only one requirement is provided and is proposed for a “High” VRF.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: Requirement R1, criterion 6 of PRC-023-2 – Transmission Relay Loadability addresses similar concerns regarding Transmission lines and is also a “High” VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: The results of the reports into the August 2003 blackout, as well as the subsequent analysis, clearly demonstrate that violating this requirement, under abnormal or emergency conditions, could cause or contribute to cascading failures on the Bulk Electric System.

VRF Justifications – PRC-025-2, R1	
Proposed VRF	**High**
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle more than one obligation.

Proposed VSLs for PRC-025-2, R1				
R1	**Lower**	**Moderate**	**High**	**Severe**
R1	N/A	N/A	N/A	The Generator Owner, Transmission Owner, or Distribution Provider did not apply settings in accordance with PRC-025-2 – Attachment 1: Relay Settings, on an applied load-responsive protective relay.
VSL Justifications – PRC-025-2, R1				
NERC VSL Guidelines				The NERC VSL guidelines are satisfied by identifying noncompliance based on “pass-fail” or a binary condition. The entity either “applied” or “did not apply” the setting(s) in accordance with Attachment 1: Relay Settings; therefore, the Violation Severity Level must be designated Severe.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance				The VSL is not changing from the current approved version; therefore, there is no lowering the current level of compliance.

Proposed VSLs for PRC-025-2, R1	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The single proposed VSL is a binary VSL (pass-fail). The entity either "applied" or "did not apply" the setting(s) in accordance with Attachment 1: Relay Settings; therefore, the VSL is proposed to be "Severe" in accordance with the criteria for binary VSLs. Guideline 2b: The proposed VSL is clear and unambiguous.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is consistent with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL addresses each individual instance of violations by basing the violations on failing to apply the setting(s) on "an applied load-responsive protective relay" in accordance with Attachment 1: Relay Settings.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

This is the first draft of the proposed standard.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	October 29, 2015
SAR posted for comment	May 26 – June 24, 2016
Informal Comment Period	April 25 – May 24, 2017

Anticipated Actions	Date
45-day formal comment period with initial ballot	September 2017
45-day formal comment period with additional ballot	November 2017
10-day final ballot	February 2018
Board adoption	May 2018

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None.

Upon Board adoption, the rationale boxes will be moved to the Supplemental Material Section.

A. Introduction

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

2. **Number:** **TPL-001-45**

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)~~

5. ~~Requirements~~Effective Date: See Implementation Plan.

B. Requirements and Measures

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~~MOD-032 standard, 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.~~as selected in consultation with the Reliability Coordinator for the Near-Term Planning Horizon for analyses pursuant to Requirement R2, parts 2.1.3 and 2.4.3.

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.

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, MOD-032~~ MOD-032 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.

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~~assessed. The ~~studies~~analysis 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. 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.

~~**2.4.3.**~~**2.4.4.** 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.

~~**2.4.4.**~~**2.4.5.** 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 assessed. Based upon this assessment, an analysis shall be performed for the selected P1 and P2 category events identified in Table 1 for which the unavailability is expected to produce more severe System impacts on its portion of the BES. The analysis shall simulate the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

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~~ Remedial Action Scheme.

- 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.

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.

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. ~~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. ~~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.

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.

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~~Remedial Action Scheme 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.

4.2.1. If the analysis concludes there is Cascading caused by the occurrence of extreme events, excluding extreme events 2e-2h in the stability column, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

4.2.2. If the analysis concludes there is Cascading caused by the occurrence of extreme events 2e-2h in the stability column, an evaluation of possible actions designed to prevent the System from Cascading shall:

4.2.2.1. List System deficiencies, the associated actions needed to prevent the System from Cascading, and the associated timetable for implementation.

4.2.2.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status.

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. ~~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. ~~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. ~~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.

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.

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]*

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.

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]*

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.

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]*

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.

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.

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.

~~B.~~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 ~~**1.1 Compliance Enforcement Authority**~~

~~Regional Entity~~ applicable entity shall keep data identified in Measures M1 through M8 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 Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.

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

~~1.2~~ Compliance Monitoring Period and Reset Timeframe

1.4. :

Not applicable.

1.5. Compliance Monitoring and Enforcement Processes:

- Compliance Audits
- Self-Certifications
- Spot Checks
- Compliance Violation Investigations
- Self-Report
- Complaints

~~1.3~~ Additional Compliance Information

1.6. :

None~~-~~.

Violation Severity Levels

R #	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~~ MOD-032 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.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
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. OR The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events.	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 Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.	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. 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 4.1 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 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

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		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 Contingency analysis as described in Requirement R4, Part 4.3. ~~OR~~ ~~The responsible entity did not develop a Corrective Action Plan as described in Requirement R4, Part 4.6.~~	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.
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.

~~C.~~D. Regional Variances

~~None.~~

E. Associated Documents

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	

Version	Date	Action	Change Tracking
		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.	
5	TBD	Adopted by the NERC Board of Trustees.	Revised To address reliability issues as identified in FERC Order No. 754 and Order No. 786 directives and update the references to the MOD Reliability Standards in TPL-001.

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)

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.

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

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P5 Multiple Contingency *(Fault plus ~~relay~~ non-redundant component of a Protection System failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant ~~relay~~ component of a Protection System[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.

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 fault on generator with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.
   f. 3Ø fault on Transmission circuit with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.

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.	g. 3Ø fault on transformer with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing. h. 3Ø fault on bus section with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing. ~~d.~~i. 3Ø internal breaker fault. ~~e.~~j. 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.

Table 1 – Steady State & Stability Performance Footnotes
(Planning Events and Extreme Events)

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. For purposes of this standard, non-redundant components of a Protection System to consider are as follows:
    1. A single protective relay which responds to electrical quantities, without an alternative that provides comparable Normal Clearing times, e.g. sudden pressure relaying;
    2. A single communications system, necessary for correct operation of a communication-aid protection scheme required for Normal Clearing, which is not monitored or not reported;
    3. A single dc supply associated with protective functions, and that single station dc supply is not monitored or not reported for both low voltage and open circuit;
    4. A single control circuitry associated with protective functions including the trip coil(s) of the circuit breakers or other interrupting devices.~~Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 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:

~~6.~~1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues

~~7.~~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

~~8.~~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

~~9.~~4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns

~~10.~~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:

~~9.~~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

~~10.~~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

~~11.~~3. Estimated frequency of Non-Consequential Load Loss under footnote 12 based on historical performance

~~12.~~4. Expected duration of Non-Consequential Load Loss under footnote 12 based on historical performance

~~13.~~5. Future plans to alleviate the need for Non-Consequential Load Loss under footnote 12

~~14.~~6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote 12

~~15.~~7. Alternatives to Non-Consequential Load Loss considered and the rationale for not selecting those alternatives under footnote 12

~~16.~~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:

~~2.~~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)

~~3.~~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.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

This is the first draft of the proposed standard.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	October 29, 2015
SAR posted for comment	May 26 – June 24, 2016
30-day Informal Comment Period	April 25 – May 24, 2017

Anticipated Actions	Date
45-day formal comment period with initial ballot	September 2017
45-day formal comment period with additional ballot	November 2017
10-day final ballot	February 2018
Board adoption	May 2018

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None.

Upon Board adoption, the rationale boxes will be moved to the Supplemental Material Section.

A. Introduction

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

2. **Number:** **TPL-001-5**

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: See Implementation Plan.**

B. Requirements and Measures

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-032 standard, 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) as selected in consultation with the Reliability Coordinator for the Near-Term Planning Horizon for analyses pursuant to Requirement R2, parts 2.1.3 and 2.4.3.

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 .

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-032 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.

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, ~~as selected in consultation with the Reliability Coordinator,~~ with known outages modeled as ~~specified~~ 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~~ assessed. The

~~studies~~analysis 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. 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.

2.4.4. 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.

2.4.5. 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~~assessed. Based upon this assessment, an analysis shall be performed for the selected P1 and P2 ~~categories~~category events identified in Table 1 ~~with~~for which the unavailability is expected to produce more severe System impacts on its portion of the BES. The analysis shall simulate the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

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~~ Remedial Action Scheme.
- 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.

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.

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.

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.

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~~Remedial Action Scheme 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.

4.2.1. If the analysis concludes there is Cascading caused by the occurrence of extreme events, excluding extreme events 2e-2h in the stability column, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

4.2.2. If the analysis concludes there is Cascading caused by the occurrence of extreme events 2e-2h in the stability column, an evaluation of possible actions designed to prevent the System from Cascading shall:

4.2.2.1. List System deficiencies, the associated actions needed to prevent the System from Cascading, and the associated timetable for implementation.

~~**4.1.3.1.**~~**4.2.2.2.** Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status.

~~**4.2.**~~**4.3.** Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall:

~~**4.2.1.**~~**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:

~~**4.2.1.1.**~~**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.

~~**4.2.1.2.**~~**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.

~~**4.2.1.3.**~~**4.3.1.3.** Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

~~**4.2.2.**~~**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.

~~**4.3.**~~**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.

~~4.3.1.~~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.

~~4.4.~~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.~~

~~**4.5.** If the analysis concludes there is Cascading caused by the occurrence of Table 1 extreme events listed in the stability column for events 2e-2h, a Corrective Action Plan shall be developed. The Corrective Action Plan shall:~~

~~**4.5.1.** List System deficiencies and the associated actions needed to prevent the System from Cascading.~~

~~**4.5.2.** Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.~~

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.

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]*

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.

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]*

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.

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]*

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.

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.

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.

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 identified in Measures M1 through ~~M7~~M8 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 Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.

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

1.4. Compliance Monitoring Period and Reset Timeframe: Not applicable.

1.5. Compliance Monitoring and Enforcement Processes:

- Compliance Audits
- Self-Certifications
- Spot Checks
- Compliance Investigations
- Self-Reports
- Complaints

1.6. Additional Compliance Information: None.

Violation Severity Levels

R #	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-032 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.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
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. OR The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events.	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 Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.	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. 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	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements	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.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		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.	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. ~~OR~~ ~~The responsible entity did not develop a Corrective Action Plan as described in Requirement R4, Part 4.6.~~	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.
R7.	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				or joint responsibilities for performing required studies.

D. Regional Variances

None.

E. Associated Documents

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	

Version	Date	Action	Change Tracking
		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.	
5	TBD	Adopted by the NERC Board of Trustees.	Revised To address reliability issues as identified in FERC Order No. 754 and Order No. 786 directives and update the references to the MOD Reliability Standards in TPL-001.

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

Category	Initial Condition	Event 1	Fault Type 2	BES Level 3	Interruption of Firm Transmission Service Allowed 4	Non-Consequential Load Loss Allowed
P5 Multiple Contingency *(Fault plus non-redundant component of a Protection System failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant component of a Protection System[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:

1. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.
2. 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.

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] resulting in Delayed Fault Clearing.
   b. 3Ø fault on Transmission circuit with stuck breaker[10] resulting in Delayed Fault Clearing.
   c. 3Ø fault on transformer with stuck breaker[10] resulting in Delayed Fault Clearing.
   d. 3Ø fault on bus section with stuck breaker[10] resulting in Delayed Fault Clearing.
   e. 3Ø fault on generator with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.

Table 1 – Steady State & Stability Performance Extreme Events	
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.	f. 3Ø fault on Transmission circuit with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing. g. 3Ø fault on transformer with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing. h. 3Ø fault on bus section with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing. i. 3Ø internal breaker fault. j. 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

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)

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. For purposes of this standard, non-redundant components of a Protection System to consider are ~~as follows~~:

    a. A single protective relay which responds to electrical quantities, without an alternative that provides comparable Normal Clearing times, e.g. sudden pressure relaying;

    b. A single communications system, necessary for correct operation of ~~protective functions~~ a communication-aided protection scheme required for Normal Clearing, which is not monitored or not reported;

    c. A single dc supply associated with protective functions, and that single station dc supply is not monitored or not reported for both low voltage and open circuit;

    d. A single control circuitry associated with protective functions ~~through~~including the trip coil(s) of the circuit breakers or other interrupting devices.

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.

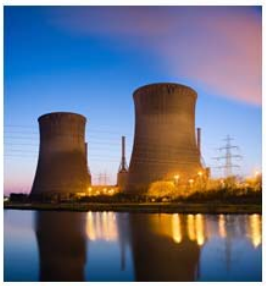
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Project 2015-10

Single Points of Failure TPL-001 Technical Rationale

September 2017

RELIABILITY | ACCOUNTABILITY



3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

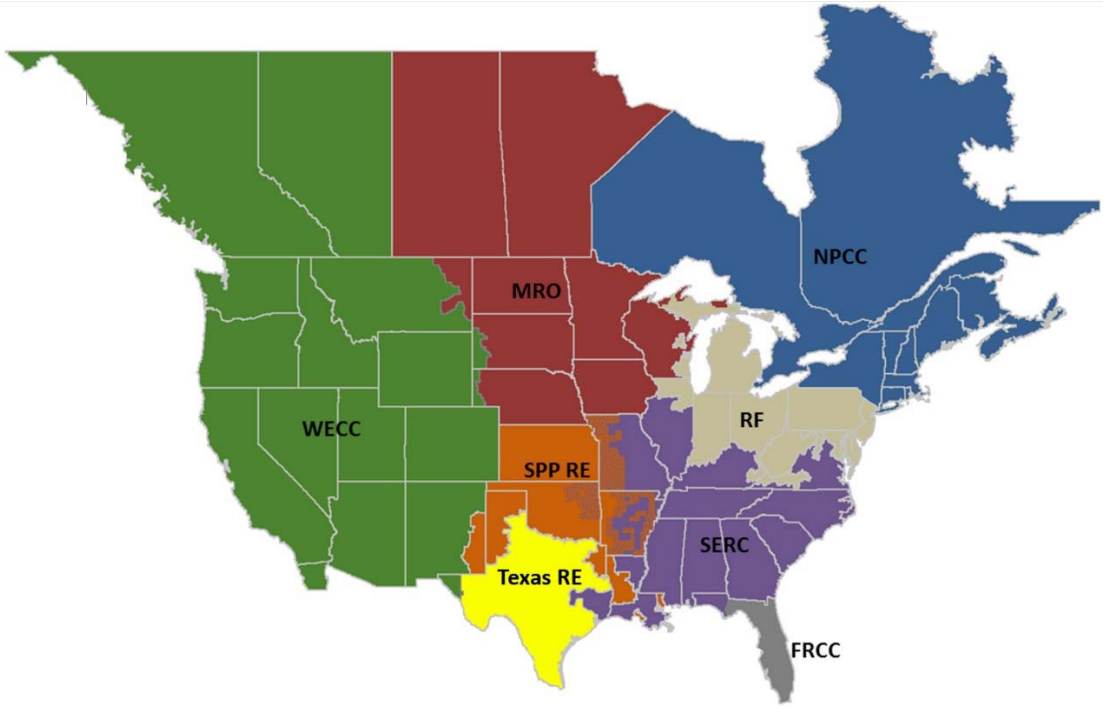
Table of Contents

Preface iii
Executive Summary iv
Key Concepts of FERC Order No. 754 iv
Key Concepts of FERC Order No. 786 iv
Summary of proposed revisions: iv
Introduction 1
Background 1
FERC Order No. 754 1
FERC Order No. 786 1
Section 1: Single Points of Failure on Protection Systems (FERC Order No. 754) 1
NERC Advisory 1
FERC Order No. 754 1
FERC Technical Conference 1
Joint SPCS-SAMS Report 1
Revisions to TPL-001-4 2
Table 1-Footnote 13 2
Requirement R4 Part 4.2 Extreme Events 4
Section 2: FERC Order No. 786 Directives 6
Background 6
Order No. 786 P. 40: Maintenance outages in the Planning Horizon 6
NERC SAMS Whitepaper Recommendations 6
Revisions to TPL-001-4 7
Requirement R1 Part 1.1.2 7
Order No. 786 P 89: Dynamic assessment of outages of critical long lead time equipment 7
NERC SAMS Whitepaper Recommendations 7
Revisions to TPL-001-4 8
Requirement R2 Part 2.4.5 8
Section 3: Applicability 9

Preface

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

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



The North American BPS is divided into eight RE boundaries. The highlighted areas denote overlap as some load-serving entities participate in one Region while associated transmission owners/operators participate in another.

FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
SPP RE	Southwest Power Pool Regional Entity
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Executive Summary

Project 2015-10 Technical Rationale provides the background and rationale for proposed revisions to Reliability Standard TPL-001-4. The proposed revisions address reliability issues concerning the study of single points of failure (SPF) on Protection Systems from FERC Order No. 754, directives from FERC Order No. 786 regarding planned maintenance outages and spare equipment strategy for stability analysis, and replaces references to the MOD-010 and MOD-012 standards with the MOD-032 Reliability Standard.

Key Concepts of FERC Order No. 754

The Standards Development Team (SDT) took into account the recommendations for modifying NERC Reliability Standard TPL-001-4 identified in the SPCS and SAMS report titled *Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request*. Proposed revisions changes extreme event (3-phase fault) to include a fault and failure of a non-redundant component of a Protection System. In "Table 1 – Steady State and Stability Performance Extreme Events," breaker failure and failure of a non-redundant component of a Protection System are differentiated. The SDT recognizes that sequence of Protection System action leading to Delayed Clearing may be quite different between the two causalities. Footnote 13 expands Protection System components to be considered for Category P5 and for extreme events 2e through 2h.

Key Concepts of FERC Order No. 786

The SDT considered the Commission's concern that the outages of significant facilities less than six months could be overlooked for planning purposes, Category P3 and P6 do not sufficiently cover planned maintenance outages, and Near-Term Transmission Planning Horizon requires annual assessments using Year One or year two, and year five, and known planned facility outages of less than six months should be addressed so long as their planned start times and durations may be anticipated as occurring for some period of time during the planning time horizon. Proposed revisions remove the six month outage duration and replace it with consultation with the Reliability Coordinator (RC) to identify known outages of significant facilities that cannot be readily managed through near-term operational coordination processes. Proposed revisions includes stability study for long lead equipment that does not have a spare.

Summary of proposed revisions:

- Requirement R1 – Updated for MOD-032-1 standard.
- Requirement R1, Part 1.1.2 – Modified how known outages are selected for study.
- Requirement R2, Part 2.1.3 – Modified the P1 contingency events simulated (steady state) for known outages.
- Requirement R2, Part 2.4.3 – Added model conditions for stability analysis of P1 events for known outages.
- Requirement R2, Part 2.4.5 – Added stability analysis requirement for long lead time equipment unavailability.
- Requirement R4, Part 4.2 – Added documentation requirement if Cascading observed given 3-phase fault SPF.
- Table 1 – Modified Category P5 event to include SPF.
- Table 1 – Modified Extreme Events, Stability column to differentiate SPF from stuck breaker.
- Table 1 – Modified Footnote 13 to specify SPF.

Introduction

NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) is being modified to address reliability issues and standard modification directives contained in FERC Order No. 754[1] and FERC Order No. 786.[2] Proposed Reliability Standard TPL-001-5 revises the TPL-001 standard to address the reliability risks posed by SPF on Protection Systems.

Background

FERC Order No. 754

FERC Order No. 754 directed NERC to study the reliability risk associated with single points of failure (SPF) in Protection Systems. The NERC System Protection and Control Subcommittee (SPCS) and the System Analysis and Modelling Subcommittee (SAMS) conducted an assessment of Protection System SPF in response to FERC Order 754, including analysis of data collected pursuant to a request for data or information under Section 1600 of the NERC Rules of Procedure. The SPCS and SAMS report titled *Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request* provides extensive general discussion about the reliability risks associated with a SPF. Available

FERC Order No. 786

In Order No. 786, FERC directed NERC to address two issues. The first issue is the concern that the six month outage duration threshold could exclude planned maintenance outages of significant facilities from future planning assessments. FERC directed NERC to modify TPL-001-4 to address this concern. The second issue involves adding clarity regarding dynamic assessment of outages of critical long lead time equipment, consistent with the entity's spare equipment strategy. FERC directed NERC to consider this issue upon its next review of TPL-001-4. The NERC SAMS developed a white paper documenting the technical analysis conducted by SAMS to address the two directives contained in the FERC Order 786. The white paper provides extensive general discussion regarding the directives.

[1] Order No. 754, *Interpretation of Transmission Planning Reliability Standard*, 136 FERC ¶ 61,186 (2011) ("Order No. 754").

[2] Order No. 786, *Transmission Planning Reliability Standards*, 145 FERC ¶ 61,051 (2013) ("Order No. 786").

Section 1: Single Points of Failure on Protection Systems (FERC Order No. 754)

NERC Advisory

On March 30, 2009, NERC issued an advisory[3] report notifying the industry that a SPF issue had caused three significant system disturbances in 5 years.

Transmission Owners, Generation Owners, and Distribution Providers owning Protection Systems installed on the Bulk Electric System were advised to address SPF on their Protection Systems when identified in routine system evaluations to prevent N-1 transmission system contingencies from evolving into more severe or even extreme events.

These entities were additionally advised to begin preparing an estimate of the resource commitment required to review, re-engineer, and develop a workable outage and construction schedule to address SPF on their Protection Systems.

FERC Order No. 754

In Order No. 754 Paragraph 20, FERC directed NERC to "to make an informational filing within six months of the date of the issuance of this Final Rule explaining whether there is a further system protection issue that needs to be addressed and, if so, what forum and process should be used to address that issue and what priority it should be accorded relative to other reliability initiatives planned by NERC."

FERC Technical Conference

A FERC technical conference concerning the Commission's Order 754 titled Staff Meeting on Single Points of Failure on Protection Systems was held on October 24-25, 2011 at FERC in Washington, DC.

At the Technical Conference, the attendees discussed the SPF issue and narrowed their concerns into four consensus points:

- The concern with assessment of SPF is a performance-based issue, not a full redundancy issue.
- The existing approved standards address assessments of SPF.
- Assessments of SPF of non-redundant primary protection (including backup) systems need to be sufficiently comprehensive.
- Lack of sufficiently comprehensive assessments of non-redundant primary Protection Systems is a reliability concern.

Joint SPCS-SAMS Report

One outcome of the FERC Technical Conference was that NERC would conduct a data collection effort to provide a broad factual foundation that could aid in assessing the reliability risks posed by SPF. The NERC Board of Trustees approved the request for data or information under Section 1600 of the NERC Rules of Procedure ("Order No. 754 Data Request") on August 16, 2012.

In September 2015, SPCS and SAMS issued a report to the NERC PC/OC, summarizing the information collected under the Order No. 754 Data Request. The assessment confirmed the existence of a reliability risk associated

[3] *See Industry Advisory: Single Point of Failure*

with SPF in Protection Systems that warrants further action. To address this risk, the SPCS and the SAMS considered a variety of alternatives and concluded that the most appropriate recommendation that aligns with FERC Order 754 directives and maximizes reliability of Protection System performance is to modify NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) through the NERC standards development process.

The report recommendations, as well as how they have been addressed in proposed TPL-001-5 by the Project 2015-10 standard drafting team are summarized in the following section.

Revisions to TPL-001-4

Table 1-Footnote 13

The SPCS/SAMS report recommended replacing "relay" with "component of a Protection System" in the Table 1 P5 event and replace Footnote 13 in TPL-001-4 with the following alternate wording:

> The components from the definition of 'Protection System' for the purposes of this standard include (1) protective relays that respond to electrical quantities, (2) single station DC supply that is not monitored for both low voltage and open circuit, with alarms centrally monitored (i.e., reported within 24 hours of detecting an abnormal condition to a location where corrective action can be initiated), and (3) DC control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

This revision to Footnote 13 clarifies the components of the Protection System that must be considered when simulating Delayed Fault Clearing due to the failure of a non-redundant component of a Protection System. This consideration is intended to account for:

- failed non-redundant components of a Protection System that may impact one or more Protection Systems;
- the duration that faults remain energized until Delayed Fault Clearing, and;
- additional system equipment removed from service following fault clearing depending upon the specific failed non-redundant component of a Protection System.

The SPCS/SAMS report described voltage or current sensing devices as having a lower level of risk of failure to trip due to robustness and likelihood to actually cause tripping upon failure. Therefore, these components of a Protection System are omitted from Footnote 13.

Noting that Requirements R3.3.1 and R4.3.1 require simulation of Protection System action, the drafting team sought to limit the scope of Footnote 13, item 1 with respect to protective relays that may be non-redundant components of a Protection System. Specifically, Footnote 13 limits single protective relays that may be a SPF to those which respond to electrical quantities and are used for primary protection resulting in Normal Clearing. An SPF in a single protective relay that is a non-redundant component of a Protection System may result in the primary Protection System failing to properly operate, leading to Delayed Fault Clearing performed by backup protective relays and/or overlapping zonal protection. Conversely, the drafting team did not include backup protective relays in the scope of Footnote 13, item 1 given that an SPF in a single protective relay used for backup protection will not affect primary protection resulting in Normal Clearing.

The drafting team recognizes that Bulk Electric System (BES) Elements are predominantly protected by relays which respond to electrical quantities. However, in some Protection System designs, non-redundant single protective relays which respond to electrical quantities may be redundant to protective relays that do not respond to electrical quantities. For example, an independent differential relay and independent sudden pressure relay may protect the same transformer from faults inside the transformer tank. In this example, the differential relay responds to electrical quantities, while the sudden pressure relay does not. While the transformer differential relay may be an SPF, an internal transformer tank fault may not lead to Delayed Clearing given the sudden pressure protection. Subsequently, the P5 event for a single phase-to-ground (line-to-ground) fault in the transformer tank need not be simulated for Delayed Fault Clearing due to the SPF of the transformer differential relay, but should be simulated for the sudden pressure relay clearing time, which may not be delayed. However, care must be taken when evaluating protective relays which respond to electrical quantities in combination with protective relays which do not respond to electrical quantities; in this same example, faults that occurred outside of the transformer tank given the SPF of the non-redundant transformer differential relay would be unaffected by the presence of the sudden pressure relay and would lead to delayed clearing, necessitating its assessment as a P5 event.

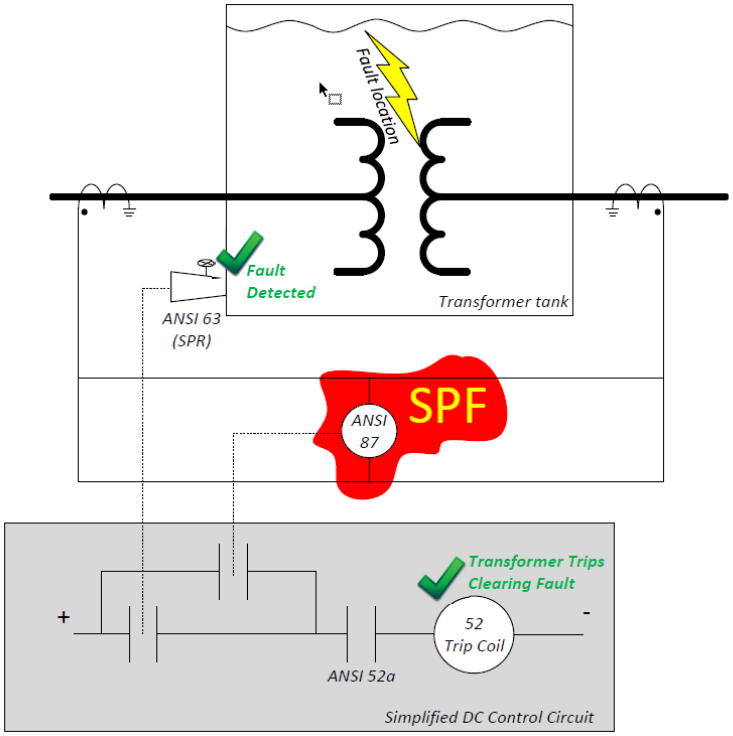


Figure 2.1: Internal Transformer Tank Fault with Sudden Pressure Protection and failed Transformer Differential Relay

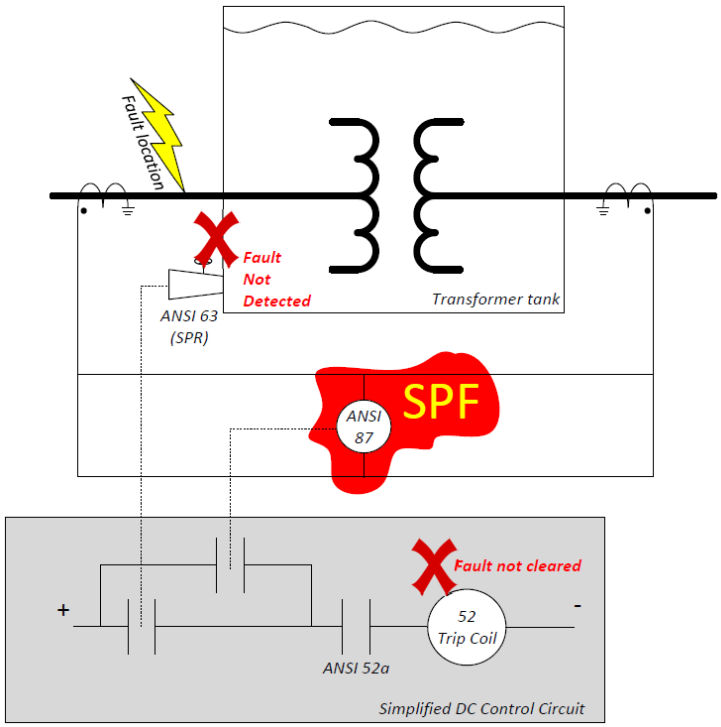


Figure 2.2: External Transformer Tank Fault with Sudden Pressure Protection and failed Transformer Differential Relay

Given the increasing importance of communication-aided Protection Systems (e.g., pilot protection schemes, direct transfer tripping schemes, permissive transfer tripping schemes, line differential relaying schemes, etc.), the proper operation of the communication system must be considered when considering potential SPF components of Protection Systems. The drafting team augmented the SAMS/SPCS recommendations to include reference to the subset of communication systems that are part of a communication-aided Protection System, necessary where the performance of that Protection System is required to achieve Transmission System Planning (TPL) Performance Requirements, enumerated in Table 1 of TPL-001-4. In other words, a communication-aided Protection System that may experience an SPF, causing it to operate improperly or not at all, must be considered as part of non-redundancy. The drafting team concluded that the failure of communication-aided Protection Systems may take many forms; however, by alarming and monitoring these systems, the overall risk of impact to the Bulk Electric System is reduced to an acceptable level. Most new Protection Systems deployed in the industry include communication-aided protection with component and communication failure alarms monitored at centralized Control Centers. This alarm monitoring is similar to the requirement associated with station DC supplies. Therefore, this requirement is more applicable to legacy systems that need communication-aided Protection Systems to meet performance requirements of the TPL standards.

Requirement R4 Part 4.2 Extreme Events

Analysis of the data collected under the Order No. 754 Data Request demonstrates the existence of a reliability risk associated with SPF in Protection Systems. Further, while the analysis shows that the risk from SPF is not an endemic problem and instances of SPF exposure are lower on higher voltage systems, the risk is sufficient to warrant further action. Risk-based assessment should be used to identify Protection Systems of concern (i.e., locations on the BES where there is a susceptibility to cascading if a Protection System component SPF exists). Given the risk to BES reliability, additional emphasis in planning studies should be placed on assessment of three-phase faults involving Protection System SPF. This concern (the study of Protection System SPF) is appropriately addressed as an extreme event in TPL-001-4, Requirement R4, Part 4.2. While less probable than single-phase-to-ground faults, three-phase faults typically initiate as single-phase-to-ground and often evolve into three-phase

faults, leading to Delayed Fault Clearing scenarios more severe than the Table 1 P5 event. Therefore, TPL-001-4, Requirement R4, Part 4.5, which specifies that an evaluation of possible mitigating actions be conducted if analysis concludes there is cascading caused by the occurrence of this extreme event, is inadequate to address the risk of Protection System component SPF to the reliability of the BES. To address this concern the drafting team has modified Requirement 4 part 4.2.2 to require additional evaluation and documentation of possible actions designed to prevent the system from cascading for extreme events 2e-2h listed from the stability column of Table 1. The additional documentation shall list System deficiencies, the associated actions needed to prevent the System from Cascading, and the associated timetable for implementation. The analysis shall be reviewed in subsequent annual Planning Assessments for continued validity and implementation status. Thus, the drafting team has maintained the three-phase-fault given a Protection System component SPF as an extreme event, but modified Requirement R4, Part 4.2.2 to require additional evaluation and documentation of possible actions, including a timetable of implementation, designed to prevent the system from Cascading. This consideration is intended to account for:

- failed non-redundant components of a Protection System that may impact one or more Protection Systems;
- the duration that faults remain energized until Delayed Fault Clearing, and;
- Additional system equipment removed from service following fault clearing depending upon the specific failed non-redundant component of a Protection System.

Footnote 13 provides the attributes of the specific non-redundant Protection System components that the entity shall consider for evaluation.

Section 2: FERC Order No. 786 Directives

Background

In addition to addressing reliability issues involving SPF on Protection Systems, proposed Reliability Standard TPL-001-5 revises the TPL-001 standard to address two directives from FERC Order No. 786.

Order No. 786 P. 40: Maintenance outages in the Planning Horizon

FERC Order No. 786, Paragraph 40 directs NERC to modify Reliability Standard TPL-001-4 to address the concern that the six month threshold could exclude planned maintenance outages of significant facilities from future planning assessments. Order No. 786 provides the following considerations:

- Planned maintenance outages less than six months may result in impacts during peak and off-peak periods;
- Planned outages during those times should be considered to allow for a single element to be taken out of service without compromising the ability to meet demand;
- Criticality of elements taken out for maintenance could result in N-1 outage and loss of non-consequential load or impact to reliability;
- Planned outages are not "hypothetical outages" and should not be treated as multiple contingencies in the planning standard (should be addressed in N-0 base case);
- Relying on Category P3 and P6 is not sufficient and does not cover maintenance outages;
- The Near-Term Transmission Planning Horizon requires annual assessments using Year One or year two and year five. Known planned facility outages of less than six months should be addressed so long as their planned start times and durations may be anticipated as occurring for some period of time during the planning time horizon.

NERC SAMS Whitepaper Recommendations

To address this directive, the NERC SAMS recommended modifications to NERC Reliability Standards IRO-017-1 and TPL-001-4. The SAMS recommended that IRO-017-1 be used as the vehicle to assure that all types of known scheduled outages are being reviewed and coordinated to mitigate reliability impact as the most cost-effective means to address the intent of the NERC directive. The coordination process developed pursuant to IRO-017-1, Requirement R1 should be used to direct how all known scheduled outages are reviewed and the actions that must be taken. The SAMS recommended that following objectives should be added to R1:

- Describe how the review of known scheduled outages by the RC, PC, TO, and TP will be integrated into transmission plan development.
- Describe whether, how, and which known scheduled outages should be included in the Planning Assessment for the Near-Term Transmission Planning Horizon required by TPL-001-4.
- Describe how emerging challenges and the inability to schedule outages will be communicated from the TO and RC to the TP and PC to be addressed in a future Corrective Action Plan pursuant to TPL-001-4.

The NERC SAMS also recommended modifying TPL-001-4, Requirement 1.1.2 by removing "with duration of at least six months" and adding language referencing the outage coordination process developed in IRO-017-1, Requirement R1 as described above.

Revisions to TPL-001-4

Requirement R1 Part 1.1.2

The drafting team modified Requirement 1.1.2 consistent with FERC's directive and included necessary consultation with the Reliability Coordinator. This consultation is expected to assist the Transmission Planner and Planning Coordinator select known outages that are relevant, not hypothetical, and have a credible likelihood of being concurrent.

The change to Requirement 1, Part 1.1.2 eliminates the specified six month outage duration and provides the opportunity for the Reliability Coordinator to assist the Planning Coordinator and/or Transmission Planner to determine which known outages, if any, need to be considered in the Planning Assessment for the Near-Term. This change is for coordination of known outages beyond the Operations Planning time horizon.

Order No. 786 P 89: Dynamic assessment of outages of critical long lead time equipment

In paragraph 89 of Order No. 786, FERC stated:

> The spare equipment strategy for steady state analysis under Reliability Standard TPL-001-4, Requirement R2, Part 2.1.5 requires that steady state studies 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. The Commission believes that a similar spare equipment strategy for stability analysis should exist that requires studies to be performed for P0, P1 and P2 categories with the conditions that the system is expected to experience during the possible unavailability of the long lead time equipment.

FERC did not direct a change but did direct NERC to consider this issue upon the next review cycle of TPL-001-4. The Project 2015-10 Standard Authorization Request included this issue within the scope of this project.

NERC SAMS Whitepaper Recommendations

The NERC SAMS considered the following key points related to FERC's Paragraph 89 guidance:

- Removal of Elements in the Planning Assessment for spare equipment strategy is only applicable for those Elements that have "a lead time of one year or more."
- Each long-lead time Element that is removed from service creates a new operating condition considered the "normal" (P0) condition for Table 1. The applicable contingencies will be studied with that Element removed from service in the pre-contingency state for stability analysis. For example, if a long-lead time transformer does not have a spare, it would be studied as a P1.3 event. Since P0 does not include an Event, P0 does not and should not be included in the stability analysis section for long-lead time Elements not included as part of a spare equipment strategy.
- System adjustments may need to be made to the power flow base case to accurately reflect reasonable and expected operating conditions with that Element removed from service in the pre-contingency (P0) operating state.
- TPL-001-4, Requirement R4.1.1, related to P1 Events, requires that no generating unit pull out of synchronism. The outage of a long-lead time Element followed by a P1 contingency should not result in a generating unit losing synchronism.
- TPL-001-4, Requirement R4.1.2, related to P2 Events, allows for generating units to pull out of synchronism. The outage of a long-lead time Element followed by a P2 contingency should not result in

tripping of any Transmission System Elements other than the generating unit and its directly connected Facilities.

The NERC SAMS white paper contains the flowing recommendations for stability analysis for long lead time Elements not included as part of a spare equipment strategy:

- The outage of long lead time Elements has an equally important impact from a stability standpoint as it does from a steady-state standpoint.
- The Planning Coordinator and Transmission Planner must demonstrate that they have met the TPL-001-4 performance criteria for specified contingency events and contingency combinations thereof as per Table 1. This should include long lead time outages that can occur for equipment that does not have a spare equipment strategy.
- TPL-001-4, Requirement R4.1.1 requires that no generating unit pull out of synchronism, while R4.1.2 allows for generating units to pull out of synchronism so long as the resulting instability does not result in tripping of any Transmission System Elements other than the generating unit and its directly connected Facilities. The outage of a long lead time Element followed by a P1 contingency should not result in a generating unit losing synchronism.
- While the P2 contingency allows for individual generating unit instability, the Transmission Planner and Planning Coordinator must ensure that this instability does not result in tripping of any Transmission System Elements other than the generating unit and its directly connected Facilities and therefore should include P2 contingencies event.

Revisions to TPL-001-4

Requirement R2 Part 2.4.5

Consistent with FERC's Order No. 786 guidance and the SAMS recommendations, the Project 2015-10 standard drafting team revised TPL-001-4 Requirement R2 Part 2.4.5 to add a similar requirement for stability analysis. The change to Requirement R2, Part 2.4.5, which includes similar language to that used for the steady-state analysis under R2.1.5, adds clarity that the outage of long lead time Elements has an equally important impact from a stability standpoint as it does from a steady-state standpoint and should be assessed commensurate with an entity's spare equipment strategy.

Section 3: Applicability

The requirements remain applicable to the Planning Coordinator and Transmission Planner. Coordination and cooperation between operating and planning entities in concert with asset owners will be required to implement the standard requirements. The planning and protection engineers that will need to conduct the studies and submit the data may be working for different companies or business units, and time will be required to accommodate the development of processes and data flow that cross company or business unit lines.

Generator Owners, Transmission Owners, and Distribution Providers are required to evaluate the Protection System(s) for locations on the system where a failure of a non-redundant Protection System component could result in a potential reliability risk. These entities must provide this information, as well as resulting fault clearing times, to Transmission Planners for proper study.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2015-10 Single Points of Failure
Reliability Standard TPL-001-5

Applicable Standard(s)

- TPL-001-5 – Transmission System Planning Performance Requirements

Requested Retirement(s)

- TPL-001-4 – Transmission System Planning Performance Requirements

Prerequisite Standard(s)

- None

Applicable Entities

- Planning Coordinator
- Transmission Planner

Background

Reliability Standard TPL-001-5 revises the prior version of the TPL-001 standard in three key respects:

- To address reliability issues concerning the study of single points of failure on Protection Systems, as identified in Federal Energy Regulatory Commission (FERC) Order No. 754 issued September 15, 2011, and the NERC Planning Committee System Protection and Control Subcommittee and System Analysis and Modeling Subcommittee September 2015 report titled *Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request;*
- To address directives from FERC Order No. 786 issued October 17, 2013, in which FERC approved Reliability Standard TPL-001-4; and
- To replace references to the MOD-010 and MOD-012 standards, which have been superseded by the MOD-032 Reliability Standard.

General Considerations

The 36-month implementation period for TPL-001-5 provides Planning Coordinators and Transmission Planners with time to update their annual Planning Assessments to include the new System models and studies required by the standard. This implementation period reflects consideration that Planning Coordinators and Transmission Planners will need time to develop, among other things:

- A process for coordinating with the Reliability Coordinator which known outages of generation of Transmission Facilities of less than six months shall be represented in planning studies;
- A process for establishing coordination with protection engineers to obtain the necessary data to perform the single points of failure analysis required by the standard; and
- Additional base case models and analysis.

In addition, the implementation plan includes an additional 24 month period for the development of Corrective Action Plans under TPL-001-5 to address newly-added studies involving single points of failure on Protection Systems. This implementation period reflects consideration that Planning Coordinators and Transmission Planners will need time beyond that provided to conduct the new studies and analysis to develop processes for coordination with asset owners and protection engineers to identify appropriate Corrective Action Plan actions and establish the associated timetables for completion. This includes~~:~~

- ~~Any necessary Corrective Action Plans to address Cascading caused by the occurrence of Table 1 extreme events listed in the stability column for events 2e-2h required by TPL-001-5 Requirement R4 Part 4.6; and~~

~~Any~~ any necessary Corrective Action Plans to address System performance issues for studies involving Table 1 Category P5 Multiple Contingency (Fault plus non-redundant component of a Protection System failure to operate) required by TPL-001-5 Requirement R2 Part 2.7 for the following non-redundant components of a Protection System identified in TPL-001-5 Table 1 Footnote 13, items 2-4:

- A single communications system, necessary for correct operation of ~~protective functions~~ a communication-aided protection scheme required for Normal Clearing, which is not monitored or not reported;
- A single dc supply associated with protective functions, and that single station dc supply is not monitored or not reported for both low voltage and open circuit;
- A single control circuitry associated with protective functions ~~through~~including the trip coil(s) of the circuit breakers or other interrupting devices.

Lastly, the provisions related to Corrective Action Plans including Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3) are carried forward from the TPL-001-4 implementation plan.

Effective Date

TPL-001-5 – Transmission System Planning Performance Requirements

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 36 months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided 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 36 months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Compliance Date for TPL-001-5 Requirement ~~R4, Part 4.6 and Requirement~~ 2, Part 2.7 associated with Table 1 Category P5 Footnote 13 items 2, 3, and 4

~~Entities shall not be required to comply with Requirement R4, Part 4.6 until 24 months after the effective date of Reliability Standard TPL-001-5.~~

Entitles shall not be required to comply with Requirement R2, Part 2.7 for the Table 1 Category P5 planning event for the non-redundant components of a Protection System identified in footnote 13 items 2, 3, and 4 until 24 months after the effective date of Reliability Standard TPL-001-5.

Note Regarding Corrective Action Plans

For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval of TPL-001-4, 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-001-5, 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-001-5:

- 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)

Initial Performance of Periodic Requirements

Each responsible entity shall complete the first annual Planning Assessment in accordance with TPL-001-5 by the effective date of the standard.

Each responsible entity shall complete any required Corrective Action Plans under Requirement ~~R4, Part 4.6 and Requirement~~ R2, Part 2.7 associated with the non-redundant components of a

Protection System identified in Table 1 Category P5 Footnote 13 items 2, 3, and 4 by 24 months after the effective date of Reliability Standard TPL-001-5.

Retirement Date

TPL-001-4 – Transmission System Planning Performance Requirements

Reliability Standard TPL-001-4 shall be retired immediately prior to the effective date of TPL-001-5 in the particular jurisdiction in which the revised standard is becoming effective.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Violation Risk Factor and Violation Severity Level Justifications

Project 2015-10 Single Points of Failure TPL-001

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for Requirement R4 in Project 2015-10 and Single Points of Failure TPL-001. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

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

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

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

FERC Guidelines for Violation Risk Factors

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

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

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

Guideline (3) – Consistency among Reliability Standards

FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

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

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

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

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

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

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

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

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

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

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

VRF Justification for TPL-001-5, Requirement R1

The VRF did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VSL Justification for TPL-001-5, Requirement R1

The VSL did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VRF Justification for TPL-001-5, Requirement R2

The VRF did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VSL Justification for TPL-001-5, Requirement R2

The VSL did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VRF Justification for TPL-001-5, Requirement R3

The VRF did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VSL Justification for TPL-001-5, Requirement R3

The VSL did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VRF Justification for TPL-001-5, Requirement R4

The VRF did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VSL Justification for TPL-001-5, Requirement R4

The VSL did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VRF Justification for TPL-001-5, Requirement R5
The VRF did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VSL Justification for TPL-001-5, Requirement R5
The VSL did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VRF Justification for TPL-001-5, Requirement R6
The VRF did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VSL Justification for TPL-001-5, Requirement R6
The VSL did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VRF Justification for TPL-001-5, Requirement R7
The VRF did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VSL Justification for TPL-001-5, Requirement R7
The VSL did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VRF Justification for TPL-001-5, Requirement R8
The VRF did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VSL Justification for TPL-001-5, Requirement R8
The VSL did not change from the previously FERC approved TPL-001-4 Reliability Standard.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Project 2015-10 Single Points of Failure TPL-001

Cost Effectiveness

Known Outages FERC Order No. 786

FERC Order No. 786 Paragraph 40 directs a change to address the concern that the six month threshold could exclude planned maintenance outages of significant facilities from future planning assessments. See paragraphs 33-45 for the discussion on planned maintenance outages.

Overview of Commission Determination (Paragraphs 40-45)

The commission stated in Order No. 786 Paragraph 41:

- For the reasons discussed below, the Commission finds that planned maintenance outages of less than six months in duration may result in relevant impacts during one or both of the seasonal off-peak periods.
- Prudent transmission planning should consider maintenance outages at those load levels when planned outages are performed to allow for a single element to be taken out of service for maintenance without compromising the ability of the system to meet demand without loss of load.
- We agree with commenters such as MISO and ATCLLC that certain elements may be so critical that, when taken out of service for system maintenance or to facilitate a new capital project, a subsequent unplanned outage initiated by a single-event could result in the loss of non-consequential load or may have a detrimental impact to the bulk electric system reliability.
- A properly planned transmission system should ensure the known, planned removal of facilities (i.e., generation, transmission or protection system facilities) for maintenance purposes without the loss of non-consequential load or detrimental impacts to system reliability such as cascading, voltage instability or uncontrolled islanding.

The Commission Disagreed with the following:

- Order No. 786 Paragraph 44: The existing TPL-001-4 for Category P3 covers generator maintenance outages, Category P6 covers transmission maintenance outages.
- Order No. 786 Paragraph 45: Planned outages of less than one year in duration should be addressed operationally by determining new operating limits and taking other actions to mitigate the planned outage.
- Order No. 786 Paragraph 45: Planned outages of less than six months is unnecessary since…10 year time frame.

Options Considered By Standard Drafting Team to Satisfy FERC Order

The following options considered by the NERC Standard Drafting Team for Requirement R1 Part 1.1.2 include (refer to SAMS recommendations):

Option 1 (SAMS recommendation from Order No. 754 Report):

Requirement R1, Part 1.1.2 Known outage(s) of generation or Transmission Facility(ies) ~~with a duration of at least six months.~~ as selected in consultation with the Reliability Coordinator for the Near-Term Planning Horizon for analyses pursuant to Requirement R2, parts 2.1.3 and R. 2.4.3.

Option 2

Requirement R1, Part 1.1.2 Known outage(s) of generation or Transmission Facility(ies) ~~with a duration of at least six months.~~

Option 3

Requirement R1, Part 1.1.2 Known outage(s) of generation or Transmission Facility(ies) with a duration of at least ~~six months~~ three months.

Option 4

Requirement R1, Part 1.1.2 Known outages(s) of generation or Transmission Facility(ies) with duration of at least ~~six~~ four months and any other significant planned outages of generation or Transmission Facility(ies) with a duration of less than four months that are expected to produce more severe System impacts on its portion of the BES. These outage coordinations are required to be performed for the season/load-levels that outages are normally planned at and shall be performed only in the Near-Term Transmission Planning Horizon.

Standard Drafting Team Proposal for Requirement R1 Part 1.1.2

The following is the option (Option 1) selected by the standard drafting team which satisfies the FERC Order. The following 1 option selected and in general aligns with the SAMS recommendation.

Option 1 (SAMS recommendation from Order No. 754 Report):

Requirement R1, Part 1.1.2 Known outage(s) of generation or Transmission Facility(ies) ~~with a duration of at least six months.~~ as selected in consultation with the Reliability Coordinator for the Near-Term Planning Horizon for analyses pursuant to Requirement R2, parts 2.1.3 and R. 2.4.3.

Spare Equipment Strategy FERC Order No. 786

FERC Order No. 786 Paragraph 89 the Commission believes that a similar spare equipment strategy for stability analysis should exist that requires studies to be performed for P0, P1 and P2 categories with the conditions that the system is expected to experience during the possible unavailability of the long lead time equipment. See Paragraph 85 through 89 of Order No. 786 for a discussion on spare equipment strategy.

Overview of Commission Determination (Order No. 786 Paragraphs 88-89)

The commission stated in Order No. 786:

- Order No. 786 Paragraph 88: The commission agrees that NERC has met the spare equipment strategy directive for steady state analysis under TPL-001-4 R2, Part 2.1.5.
- Order No. 786 Paragraph 88: The Commission finds that a spare equipment strategy for stability analysis is not addressed under category P6.
- Order No. 786 Paragraph 89: The commission is not persuaded by the explanation of NERC and others that a similar spare equipment strategy for stability analysis would cause unjustified burden because stability analysis is already required under category P6.

Options Considered By Standard Drafting Team to Satisfy FERC Order No. 786

Since the FERC Order in Paragraph 89 was very specific, there was only one option considered by the standard drafting team that met the requirements of the FERC Order Paragraph 89 request.

Option 1 Addition of Part 2.4.5

Requirement R1, Part 1.1.2 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~~ assessed. ~~The studies~~ Based upon this assessment, an analysis shall be performed for the selected P1 and P2 ~~categories~~ category events identified in Table 1 for which the unavailability ~~with the conditions that the System~~ is expected to produce more severe System impacts on its portion of the BES. The analysis shall simulate the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

Single Point of Failure of the Protection System

Based on Order No. 754 directive of September 15, 2011; NERC informational filing dated March 15, 2012; Section 1600 data request; and the 2nd NERC informational filing dated October 30, 2015, the SPCS/SAMS report to address the concern of Single Point Of Failure of a protection system:

- For Table 1 – Steady State & Stability Performance Planning Events, Category P5:
  - Replace "relay" with "component of a Protection System," and
  - Add superscript "13" to reference footnote 13 for the replaced term under the "Category" column.
- For Table 1 – Steady State & Stability Performance Extreme Events, under the Stability column, No. 2:
  - Remove the phrase "or a relay failure" from items a, b, c, and d to create distinct events only for stuck breakers.
  - Append four new events for the same items a, b, c, and d in the above bulleted item to create distinct events replacing "a relay failure" with "a component failure of a Protection System."

- Replace footnote 13 in TPL-001-4 with, "The components from the definition of "Protection System" for the purposes of this standard include (1) protective relays that respond to electrical quantities, (2) single – station DC supply that is not monitored for both low voltage and open circuit, with alarms centrally monitored (i.e., reported within 24 hours of detecting an abnormal condition to a location where corrective action can be initiated), and (3) DC control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices."
- Modify TPL-001-4 (Part 4.5) so that extreme event assessments must include evaluation of the three phase faults the described component failures of a Protection System that produce the more severe system impacts. For example, add a new second sentence that reads "[t]he list shall consider each of the extreme events in Table 1 – Steady State & Stability Performance Extreme Events; Stability column item number 2."

Options Considered By Standard Drafting Team to Satisfy FERC Order

Since some of the recommendations from the SPCS and SAMS report were so specific, there were no other options considered for the following:

- For Table 1 – Steady State & Stability Performance Planning Events, Category P5:
  - Replace "relay" with "component of a Protection System," and
  - Add superscript "13" to reference footnote 13 for the replaced term under the "Category" column.
- For Table 1 – Steady State & Stability Performance Extreme Events, under the Stability column, No. 2:
  - Remove the phrase "or a relay failure" from items a, b, c, and d to create distinct events only for stuck breakers.
  - Append four new events for the same items a, b, c, and d in the above bulleted item to create distinct events replacing "a relay failure" with "a component failure of a Protection System."

Different options were considered for footnote 13 language. These options are:

Option 1 Footnote 13

The Standard Drafting Team for TPL-001 considered revising footnote 13 to include all five components. In the NERC glossary of terms, a Protection System include five components. These are:

Protection System –

- Protective relays which respond to electrical quantities,
- Communications systems necessary for correct operation of protective functions
- Voltage and current sensing devices providing inputs to protective relays,

- Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

Option 2 Footnote 13

The second option was to have footnote 13 list four of the five components of a protection system but limit *"communications systems"* to only those that are not monitored or alarmed. The following is language for Footnote 13[1]:

13. For the purposes of P5 of this standard, components of a Protection System include the following:

    a. A single protective relay which responds to electrical quantities, without an alternative that provides comparable Normal Clearing times, e.g. sudden pressure relaying;

    b. A single communications system, necessary for correct operation of a communication-aided protection scheme required for Normal Clearing, which is not monitored or not reported;

    c. A single dc supply associated with protective functions, and that single station dc supply is not monitored or not reported for both low voltage and open circuit;

    ~~a.~~d. A single control circuitry associated with protective functions including the trip coil(s) of the circuit breakers or other interrupting devices.

Option 3 Footnote 13

a. The components from the definition of Protection System" for the purposes of this standard include:

b. protective relays that respond to electrical quantities,

c. single – station DC supply that is not monitored for both low voltage and open circuit, with alarms centrally monitored (i.e., reported within 24 hours of detecting an abnormal condition to a location where corrective action can be initiated), and

d. control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

Standard Drafting Team Proposal for Table 1 Footnote 13:

The Standard Drafting Team selected Option 2 which expands Protection System components to be considered to determine the impact to the BES if that component failed when a fault occurs.

[1] Failure of voltage and current sensing device would result in a breaker operation without a fault which was considered not a reliability risk to the BES.

Option 2 Footnote 13

The second option was to have footnote 13 list four of the five components of a protection system but limit *"communications systems"* to only those that are not monitored or alarmed. The following is language for Footnote 13[2]:

For the purposes of P5 of this standard, components of a Protection System include the following:

a. A single protective relay which responds to electrical quantities, without an alternative that provides comparable Normal Clearing times, e.g. sudden pressure relaying;

b. A single communications system, necessary for correct operation of a communication-aided protection scheme required for Normal Clearing, which is not monitored or not reported;

c. A single dc supply associated with protective functions, and that single station dc supply is not monitored or not reported for both low voltage and open circuit;

~~a.~~d. A single control circuitry associated with protective functions including the trip coil(s) of the circuit breakers or other interrupting devices.

Addition of Corrective Action Plan for Extreme Event Three – Phase Faults:

The SPCS and SAMS report for Order No. 754 recommended that three phase faults involving single points of failure of a protection system be addressed. Additionally, the standard drafting team recognized that the Order No. 754 data requirement collected data for a three-phase fault and not a single-line-ground fault. The Order No. 754 data collection and report indicated a risk to the BES for three phase faults involving single points of failure of a protection system.

Options Considered By Standard Drafting Team to Satisfy FERC Order

Option 1:

Do not add anything for extreme event three-phase faults with protection failure.

Option 2:

Addition of Requirement 4 Part 4.2.1 and 4.2.2 as follows:

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.

4.2.1. If the analysis concludes there is Cascading caused by the occurrence of extreme events, excluding extreme events 2e-2h in the stability column, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

[2] Failure of voltage and current sensing device would result in a breaker operation without a fault which was considered not a reliability risk to the BES.

4.2.2. If the analysis concludes there is Cascading caused by the occurrence of extreme events 2e-2h in the stability column, an evaluation of possible actions designed to prevent the System from Cascading shall:

4.2.2.1. List System deficiencies, the associated actions needed to prevent the System from Cascading, and the associated timetable for implementation~~List System deficiencies, the associated actions, and an associated timetable for implementation needed to prevent the System from Cascading~~.

4.2.2.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status.

Standard Drafting Team Proposal

The standard drafting team selected Option 2 which was to add a requirement to require a Corrective Action Plan if a three-phase fault followed by a protection failure causes cascading.

Option 2:

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.

4.2.1. If the analysis concludes there is Cascading caused by the occurrence of extreme events, excluding extreme events 2e-2h in the stability column, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

4.2.2. If the analysis concludes there is Cascading caused by the occurrence of extreme events 2e-2h in the stability column, an evaluation of possible actions designed to prevent the System from Cascading shall:

4.2.2.1. List System deficiencies, the associated actions needed to prevent the System from Cascading, and the associated timetable for implementation~~List System deficiencies, the associated actions, and an associated timetable for implementation needed to prevent the System from Cascading~~.

4.2.2.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Summary of Proposed Revisions to the NERC Standard Processes Manual

Appendix 3A to the NERC Rules of Procedure

Revisions are proposed to Sections 2.1, 3.7, 6.0, 7.0, 8.0, and 11.0 of the NERC Standard Processes Manual (SPM), Appendix 3A to the NERC Rules of Procedure.

A redline of the proposed revisions is available on the Revisions to the NERC SPM page.

The proposed revisions are posted for a 45-day formal comment period from March 20, 2017 through May 3, 2017. An initial ballot will be conducted from April 24, 2017 – May 3, 2017. All comments should be submitted through the NERC Standards Balloting and Commenting System (SBS).

Background Information

Under the oversight of the NERC Standards Committee (SC), a small group consisting of Standards Committee Process Subcommittee (SCPS) members and NERC staff have reviewed specific sections of the NERC SPM for the purpose of proposing revisions to clarify and improve existing language and processes. Below is a summary of the revisions, which have been endorsed by the SCPS and the SC and are posted for ballot and comment.

Section 6.0 - Process for Conducting Field Tests

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. The revisions were posted for informal comment from September 29, 2015 through October 28, 2015. In response to comments, revisions were made to clarify roles, responsibilities, and process steps.

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). Three new subsections are created:

> Proposed Section 6.1.1 summarizes 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. The technical committee shall provide the SC with a recommendation regarding 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 Power System. 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 6.1.3 describes that a field test may be continued, modified, or terminated in the event a conclusion cannot be formulated within the time allotted in the field test plan, subject to the approval of the lead technical committee overseeing the field test.

Proposed Section 6.2 clarifies the processes governing communication and coordination for 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 reporting on field test progress and results, including requirements to keep the NERC Board of Trustees informed regarding new and ongoing field tests and any requested compliance waivers.

Section 7.0 - Process for Developing an Interpretation

Revisions are proposed to improve the organization of the section. Additional revisions are proposed to clarify language regarding what constitutes a valid Interpretation, including clarifying that requests for approval of specific compliance approaches are not proper Interpretation requests and should instead be pursued through the applicable NERC and Regional Entity guidance processes (Section 7.2.1).

Recognizing that Interpretations provide clarity to existing standards and do not create new compliance obligations, revisions are proposed to streamline the process for posting and balloting Interpretations. Specifically, revisions are proposed to: (i) reduce the time for comment from 45 days to 30 days; (ii) eliminate the requirement for Interpretation drafting teams to respond in writing to each submitted comment; and (iii) eliminate the need for a separate final ballot following a successful initial or additional ballot.

Section 8.0 - Process for Appealing an Action or Inaction

Revisions are proposed to Sections 8.1 and 8.2 to specify that an appellant may withdraw its Level 1 or Level 2 appeal by providing written notice to the NERC Director of Standards. These revisions, which are based on lessons learned from previous appeals, would allow an appellant to withdraw its appeal in the event the issue is resolved to the appellant's satisfaction prior to the formal conclusion of the appeal.

Section 11.0 - Process for Approving Supporting Documents

Revisions are proposed to clarify that the scope of Section 11 is to define a process for approving the posting of supporting documents to approved Reliability Standards (i.e., Reliability Standards approved by applicable governmental authorities). New subsections are created to improve organization. The revisions are summarized as follows:

Section 11.1 defines the types of documents that may be posted as a supporting document to an approved Reliability Standard (Reference, Lessons Learned, White Paper). This section specifically excludes documents that contain specific compliance approaches, which are properly addressed through the applicable NERC and Regional Entity guidance processes.

Section 11.2 defines the process to be used to review and vet proposals for supporting documents. This process is designed so that each supporting document posted alongside an approved Reliability Standard: (i) is a Reference, Lessons Learned, or White Paper as defined in Section 11.1; (ii) is consistent with the purpose and intent of the associated Reliability Standard; and (iii) has had adequate stakeholder review to assess its technical adequacy. For example, stakeholders may have reviewed the document for technical adequacy during the standard development process for the associated standard. Alternatively, Section 11 provides a process for posting for stakeholder review those proposed supporting documents that have not yet been sufficiently vetted.

Section 11.3 provides for SC approval to post the supporting document along with the approved Reliability Standard on the NERC website.

Updates to Other Sections

Updates are made to Section 2.1 - Definition of a Reliability Standard, to reflect the currently effective definition of this term in the NERC Rules of Procedure.

Updates are made to Section 3.7 - Governmental Authorities, to allow for the inclusion of federal and provincial governments of non-U.S. North American jurisdictions that may approve Reliability Standards in the future.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standard Processes Manual

VERSION ~~3~~4

Effective: ~~June 26, 2013~~TBD

to ensure the reliability of the bulk power system

Table of Contents

Section 1.0: Introduction 3
Section 2.0: Elements of a Reliability Standard 6
Section 3.0: Reliability Standards Program Organization 10
Section 4.0: Process for Developing, Modifying, Withdrawing or Retiring a Reliability Standard 14
Section 5.0: Process for Developing a Defined Term 26
Section 6.0: Process~~es~~ for Conducting Field Tests ~~and Collecting and Analyzing Data~~ 28
Section 7.0: Process for Developing an Interpretation 32
Section 8.0: Process for Appealing an Action or Inaction 37
Section 9.0: Process for Developing a Variance 39
Section 10.0: Processes for Developing a Reliability Standard Related to a Confidential Issue 41
Section 11.0: Process for Approving Supporting Documents 48
Section 12.0: Process for Correcting Errata 51
Section 13.0: Process for Conducting Periodic Reviews of Reliability Standards 52
Section 14.0: Public Access to Reliability Standards Information 53
Section 15.0: Process for Updating Standard Processes 54
Section 16.0: Waiver 55

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, approved by the United States Federal Energy Regulatory Commission under Section 215 of the Federal Power Act, or approved or recognized by an applicable governmental authority in other jurisdictions, to provide for Reliable Operation of the Bulk Power System., ~~including without limiting the foregoing,~~ The term includes requirements for the operation of existing Bulk Power System ~~Facilities~~facilities, including cyber-security protection, and ~~including~~ the design of planned additions or modifications to such ~~Facilities~~ 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~~such ~~Facilities~~ facilities or to construct new transmission capacity or generation capacity. (In certain contexts, this term may also refer to a "Reliability Standard" that is in the process of being developed, or not yet approved or recognized by FERC or an applicable governmental authority in other jurisdictions). ~~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.

---

[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.

- **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, 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.

---

[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 federal or provincial governments of other North American jurisdictions that have recognized NERC as the ERO ~~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.

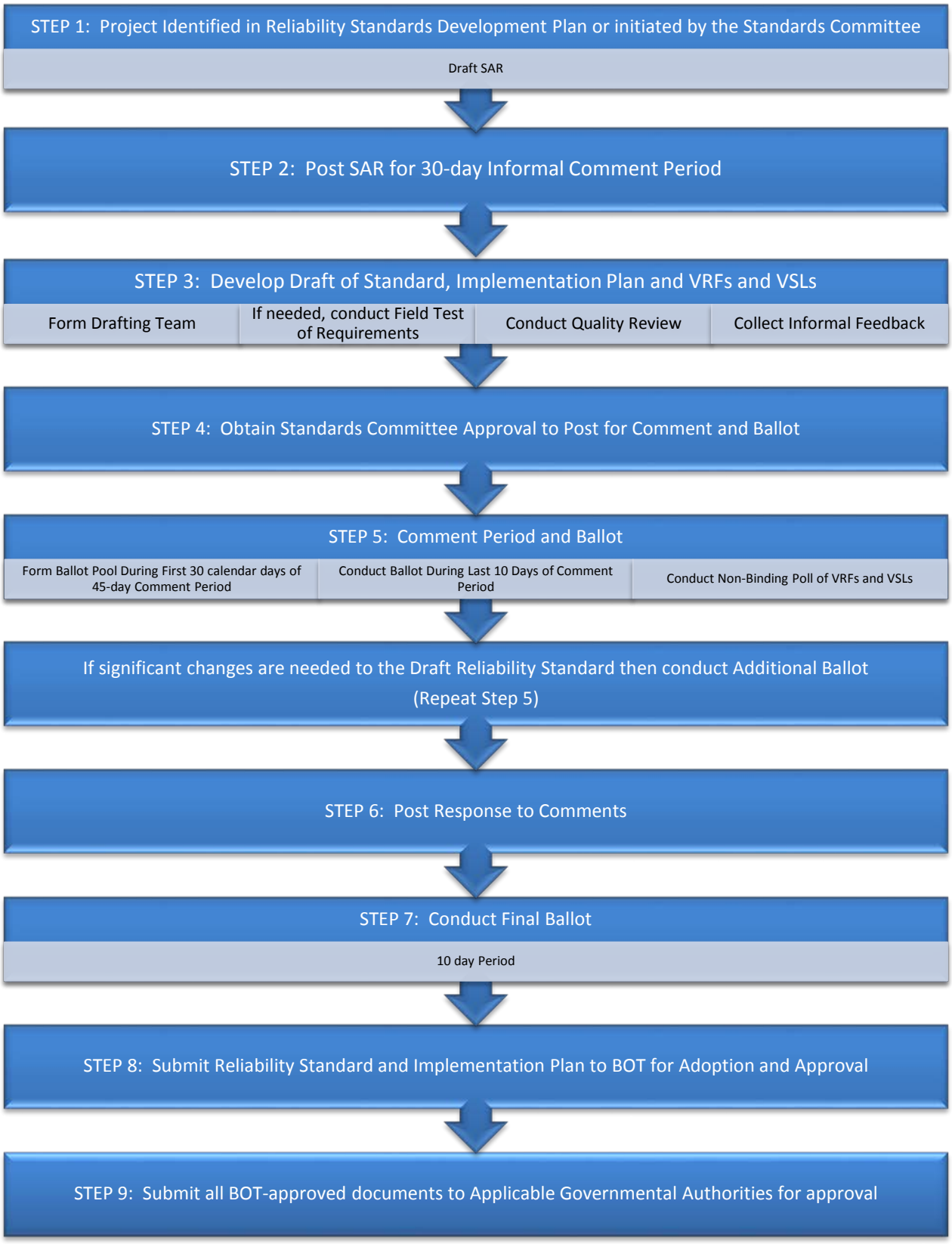


FIGURE 1: Process for Developing or Modifying a Reliability Standard

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 benefit from 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.

There are two types of field tests – tests of concepts and tests of requirements. A field test is initiated by either a SAR or Reliability Standard drafting team. The drafting team may be supplemented with other individuals based on the required technical expertise needed to support the field test. The drafting team is responsible for developing the field test plan, including the implementation schedule, and for identifying compliance related issues such as the potential need for compliance waivers.

6.1: Field Tests and Data Analysis for Validation of Concepts (collectively "field test")

- Field tests or collection and analysis of data to validate concepts that support the development of Requirements Reliability Standards should be conducted, to the extent possible, before the 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.
- To conduct a field test of a technical concept in a proposed new or revised Reliability Standard, the drafting team must work with NERC Staff to identify one of NERC's technical committees to oversee the field test as well as other technical committees with relevant technical expertise.
- The field test is conducted by the drafting team, in coordination with NERC Staff and under the oversight of the assigned technical committee, in accordance with an approved field test plan.

If a drafting team finds that it needs to collect and analyze data or conduct a field test of a concept that was not identified when 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.

6.1.1. Field Test Approval

The request to conduct a field test shall include, at a minimum:

- the field test plan,
- the implementation schedule, and
- an expectation for periodic updates of the analysis of the results to the lead NERC technical committee.

Prior to the drafting team conducting a field test, the drafting team must first receive approval from the lead NERC technical committee. Second, the drafting team must receive approval from the Standards Committee.

The lead NERC technical committee's approval shall be based on the technical adequacy of the field test plan. Following approval, the lead NERC technical committee shall provide a recommendation to the Standards Committee for the disposition of the field test plan request. The lead NERC technical committee shall coordinate all entity participation in the field test, such as accepting, adding, and withdrawing individual entities from the field test, as well as coordinating and communicating status of the results of the field test.

The Standards Committee's decision to approve the field test plan request shall be based solely on whether the Standards Committee, by majority vote, agrees or disagrees with the lead NERC technical committee's recommendation. If the Standards Committee disagrees with the lead NERC technical committee's recommendation, the Standards Committee shall inform the lead NERC technical committee with an explanation of the basis for the decision.

6.1.2: Field Test Suspension for Reliability Concerns

During the field test, if the lead NERC technical committee overseeing the field test determines that the field test is creating a reliability risk to the Bulk Power System:

- 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, with the assistance of NERC Staff, shall notify NERC Compliance Monitoring and Enforcement Program Staff to coordinate any compliance related issues such as continuance or cessation of waivers (see Section 6.2).

Prior to the field test being restarted after it has been stopped, the drafting team must resubmit the field test request and receive approval as outlined in Section 6.1.1.

6.1.3: Continuing, Modifying, or Terminating a Field Test

If the drafting team concludes that a field test does not provide sufficient information to formulate a conclusion within the time allotted in the plan, the drafting team shall provide a recommendation to either continue (including extending the duration of the field test beyond the period of standard development), modify, or terminate the field test to the lead NERC technical committee and the chair of the Standards Committee. The lead NERC technical committee shall either approve or reject a request to continue, modify, or terminate the field test, and thereafter, provide notice to the chair of the Standards Committee of its selection.

If the duration of the field test is extended beyond the period of standard development, the preliminary report and results shall be publicly posted on the NERC web site prior to the final ballot of the Reliability Standard.

~~**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.

6.32: 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 drafting team may request waivers of compliance for field test participants that would be rendered Registered Entities incapable of complying with the current Requirement(s) of an approveda 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 the The NERC Compliance Monitoring and Enforcement Program Staff prior to the approval of the field test or data collection and analysisshall determine whether to approve the requested waivers and shall be responsible for approving any modifications or terminations that may become necessary following the start of the field test. The NERC Reliability 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 Board of Trustees of the pending field test, the expected duration, and any requested waivers of compliance for Registered Entities.

During the field test, the drafting team shall provide periodic updates (no less than quarterly) on the progress of the field test to the Standards Committee and the NERC technical committees. Prior to the ballot of any standard involving a field test, the drafting team shall provide to the Standards Committee either a preliminary report of the results of the field test to date, if the field test will continue beyond standard development, or a final report if the field test has been completed. The chair of the Standards Committee shall keep the Board of Trustees 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 NERC Reliability Standards web pagesite. This posting shall include the participant list, unless it is determined that posting this list would present confidentiality or other concerns.

[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.

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.

7.1: Valid Interpretation

An Interpretation may only clarify ~~or interpret~~ the language of the Requirement(s) of an approved Reliability Standard, including, if applicable, any attachment referenced in the Requirement ~~being clarified~~. The Interpretation may not alter the scope or the language of a Requirement or referenced attachment. No other elements of an approved Reliability Standard are subject to an Interpretation.

7.2: Process for Requesting an 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 Staff~~s~~ shall review the request for ~~interpretation~~ Interpretation to determine whether it meets the requirements for a valid ~~interpretation~~Interpretation. Based on this review, ~~the~~ NERC ~~Standards and Legal~~ Staff~~s~~ shall make a recommendation to the Standards Committee whether to accept the request for Interpretation and move forward in responding to the Interpretation request.

7.2.1: Rejection of an Interpretation Request

~~For example, an~~A request for Interpretation ~~request~~ may be rejected ~~where it~~in the following circumstances:

- ~~(1)~~ Where the r~~R~~equest~~s~~ seeks approval of a particular compliance approach.[27] ~~;~~
- ~~(2) Identifies a gap or perceived weakness in the approved Reliability Standard;~~
- ~~(3)~~ Where ~~an~~ the issue can be addressed by incorporating the issue into an ~~active~~ existing or future standard ~~drafting team~~development project.~~;~~
- ~~(4)~~ Where ~~it~~ the request~~s~~ seeks clarification of any element of a Reliability Standard other than a Requirement.~~;~~
- ~~(5)~~ Where ~~a question~~the issue has already been addressed in the record.~~;~~
- ~~(6)~~ Where the ~~Interpretation~~ request 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~~the request seeks to expand the scope of a Reliability Standard.~~; or~~
- ~~(8)~~ Where the meaning of a Reliability Standard is plain on its face.

[26] The *Request for Interpretation* form is posted on the NERC Standards web page.

[27] Requests that contain specific compliance approaches, or examples of compliance, are not candidates for Interpretations and should be pursued through the applicable NERC Compliance Monitoring and Enforcement Program processes.

If the Standards Committee rejects the Interpretation request, it shall provide a written explanation for the ~~rejecting the Interpretation~~rejection to the entity requesting the Interpretation within 10 business days of the decision to reject.

7.2.2: Acceptance of an Interpretation Request

If the Standards Committee accepts the Interpretation request, the Standards Committee shall authorize NERC Reliability Standards Staff ~~shall (i) form a ballot pool and (ii)~~to assemble an Interpretation drafting team with the relevant expertise to address the request~~interpretation for approval by the Standards Committee~~.

7.3: Development of an Interpretation

As soon as practical, the Interpretation drafting team shall develop a ~~"final~~ draft~~"~~ Interpretation ~~providing the requested clarity~~addressing the request, consistent with Section 7.1. Interpretations shall be developed in accordance with the following process:

- NERC Reliability Standards staff shall review the draft Interpretation to determine whether it has met the requirements for a valid Interpretation and to provide a recommendation to the Standards Committee whether to authorize posting or remand to the Interpretation drafting team for further work.
- The Standards Committee, after review of the Staff recommendation, may authorize posting of the draft Interpretation for comment and ballot.
- Interpretations ~~will~~ shall be balloted in the same manner as Reliability Standards (*see* Section 4.0), with the following exceptions:
  - Interpretations shall be posted for a 30-day informal comment period. The Interpretation drafting team is not required to respond in writing to comments submitted during this comment period.
  - The NERC Reliability Standards Staff shall establish a ballot pool during the first 20 days of the 30-day informal comment period.
  - The ballot window shall take place during the last 10 calendar days of the 30-day informal comment period.
  - Final Ballots shall not be conducted for Interpretations. An Interpretation shall be deemed approved by the ballot pool following the first ballot in which the necessary quorum and sufficient affirmative votes are obtained.

If ~~stakeholder comments~~the ballot results indicate that there is not a consensus for the Interpretation, and the Interpretation drafting team cannot revise the Interpretation without violating the basic ~~expectations~~ criteria ~~outlined above~~for what constitutes a valid Interpretation (see Section 7.1), 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 in writing and the disposition of the Interpretation shall be posted.

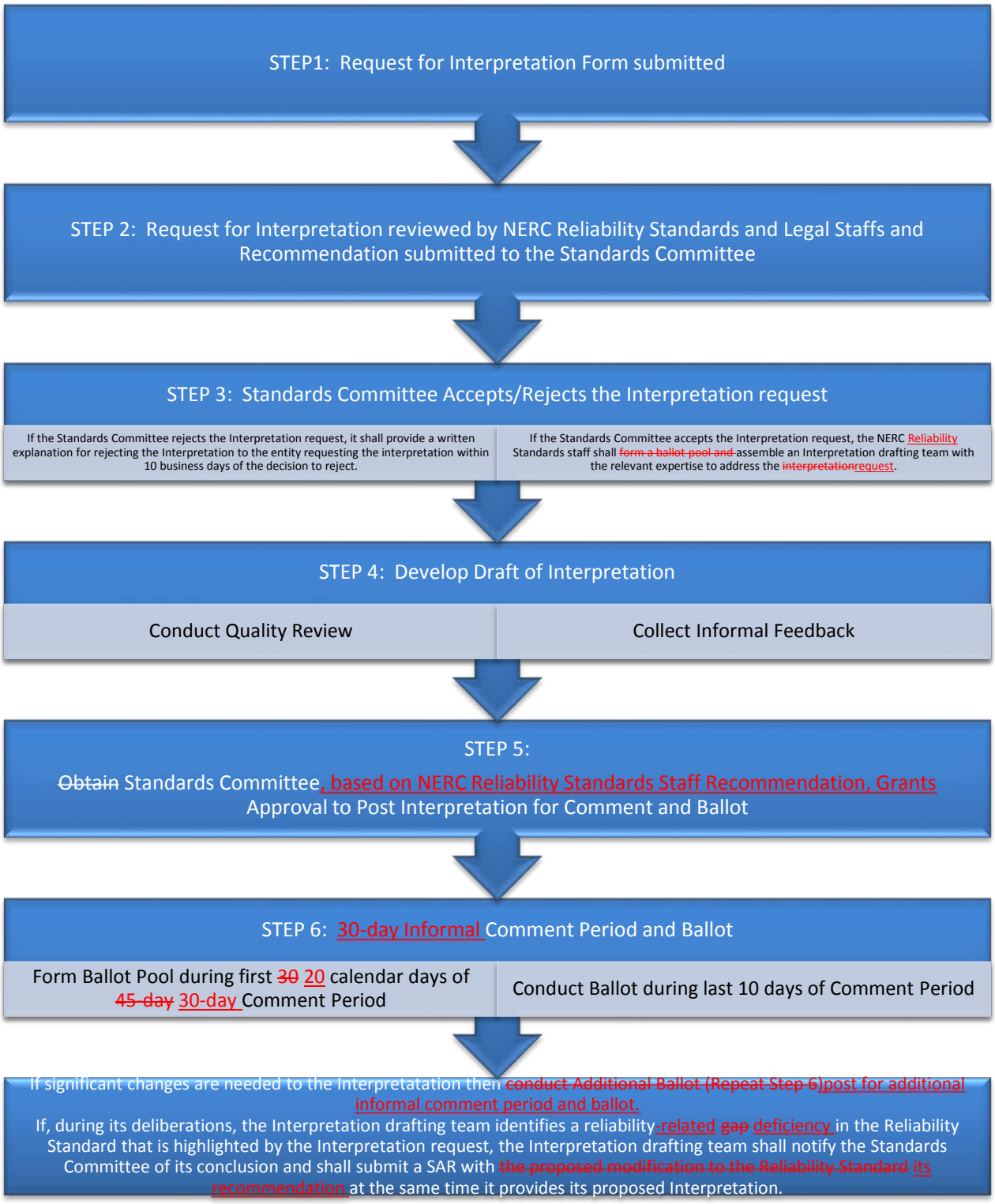
If, during its deliberations, the Interpretation drafting team identifies a reliability-related ~~gap~~ deficiency in the Reliability Standard that is highlighted by the Interpretation request, the Interpretation drafting team shall notify the Standards Committee of its conclusion and may submit a SAR with ~~the proposed modification to the Reliability Standard~~its recommendation at the same time it provides its proposed Interpretation.

If approved by the ballot pool, ~~The~~ NERC ~~Reliability Standards and Legal~~ Staff~~s~~ shall review the final Interpretation to determine whether it has met the requirements for a valid Interpretation and ~~. 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.[28]~~ If an Interpretation drafting team ~~proposes~~ recommends 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~~ recommendation at the time the Interpretation is submitted for adoption. Following ~~adoption by the~~ Board of Trustees adoption, ~~NERC Staff shall file~~ the Interpretation shall be filed ~~for approval by~~with the Applicable Governmental Authorities, and the Interpretation shall become effective when approved by those Applicable Governmental Authorities.[29] 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.

~~[28] NERC will maintain a record of all interpretations associated with each standard on the Reliability Standards page of the NERC website.~~

[29] 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 Reliability Standards staff shall form a ballot pool and assemble an Interpretation drafting team with the relevant expertise to address the interpretationrequest.
STEP 4: Develop Draft of Interpretation
Conduct Quality Review
Collect Informal Feedback
STEP 5:
Obtain Standards Committee, based on NERC Reliability Standards Staff Recommendation, Grants Approval to Post Interpretation for Comment and Ballot
STEP 6: 30-day Informal Comment Period and Ballot
Form Ballot Pool during first 30 20 calendar days of 45-day 30-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)post for additional informal comment period and ballot.
If, during its deliberations, the Interpretation drafting team identifies a reliability-related gap deficiency 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 its recommendation at the same time it provides its proposed Interpretation.

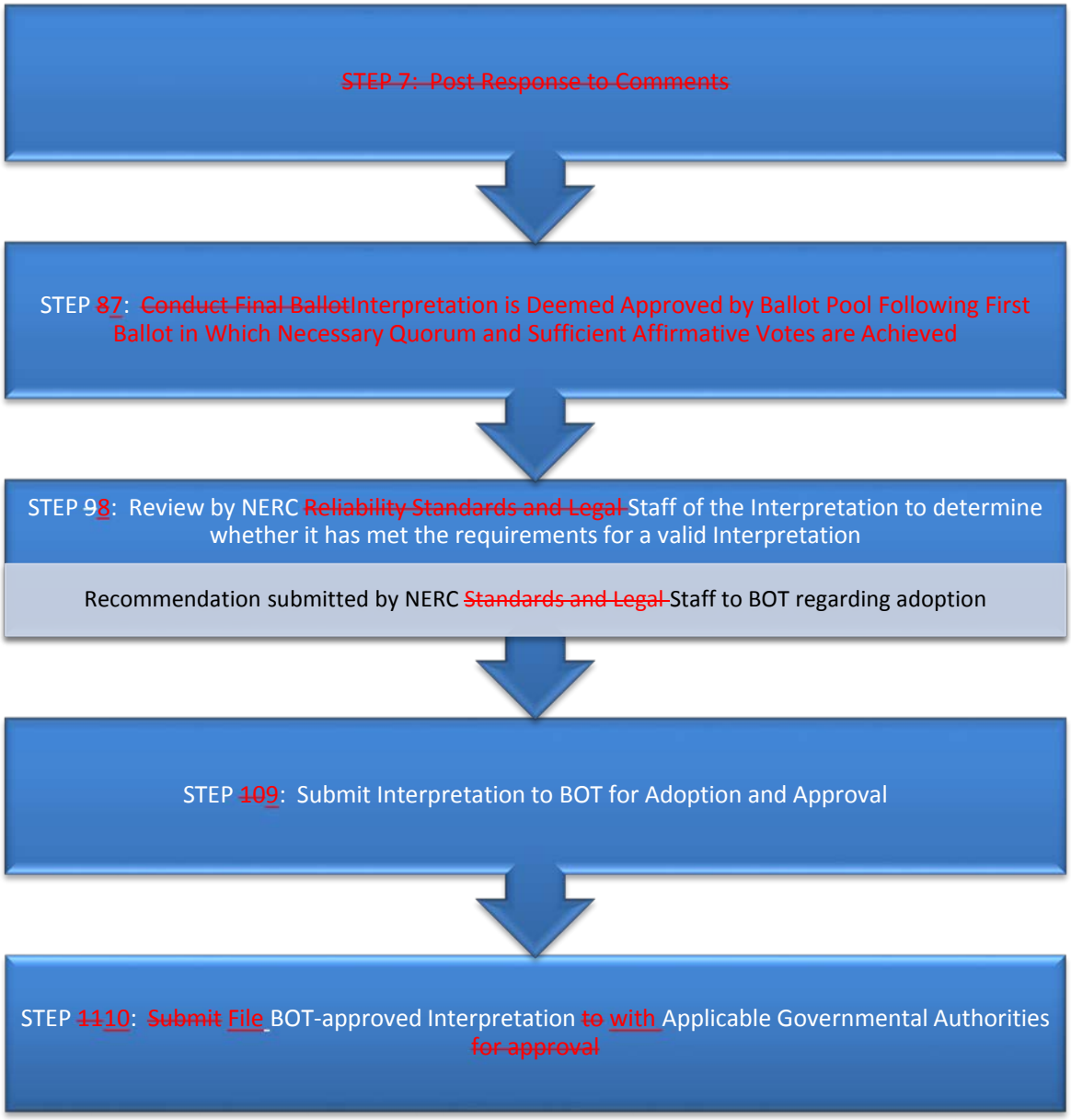


FIGURE 2: Process for Developing an Interpretation

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.

At any time prior to receiving the written response to the Level 1 Appeal, an appellant may withdraw the Level 1 Appeal with written notice to the Director of Standards.

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.

At any time prior to the meeting of the Level 2 Appeals Panel, an appellant may withdraw the Level 2 Appeal and accept the results of the Level 1 Appeal by providing written notice to the Director of Standards.

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[30] 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

[30] 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.[31]

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

[31] 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.[32] 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.

[32] 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

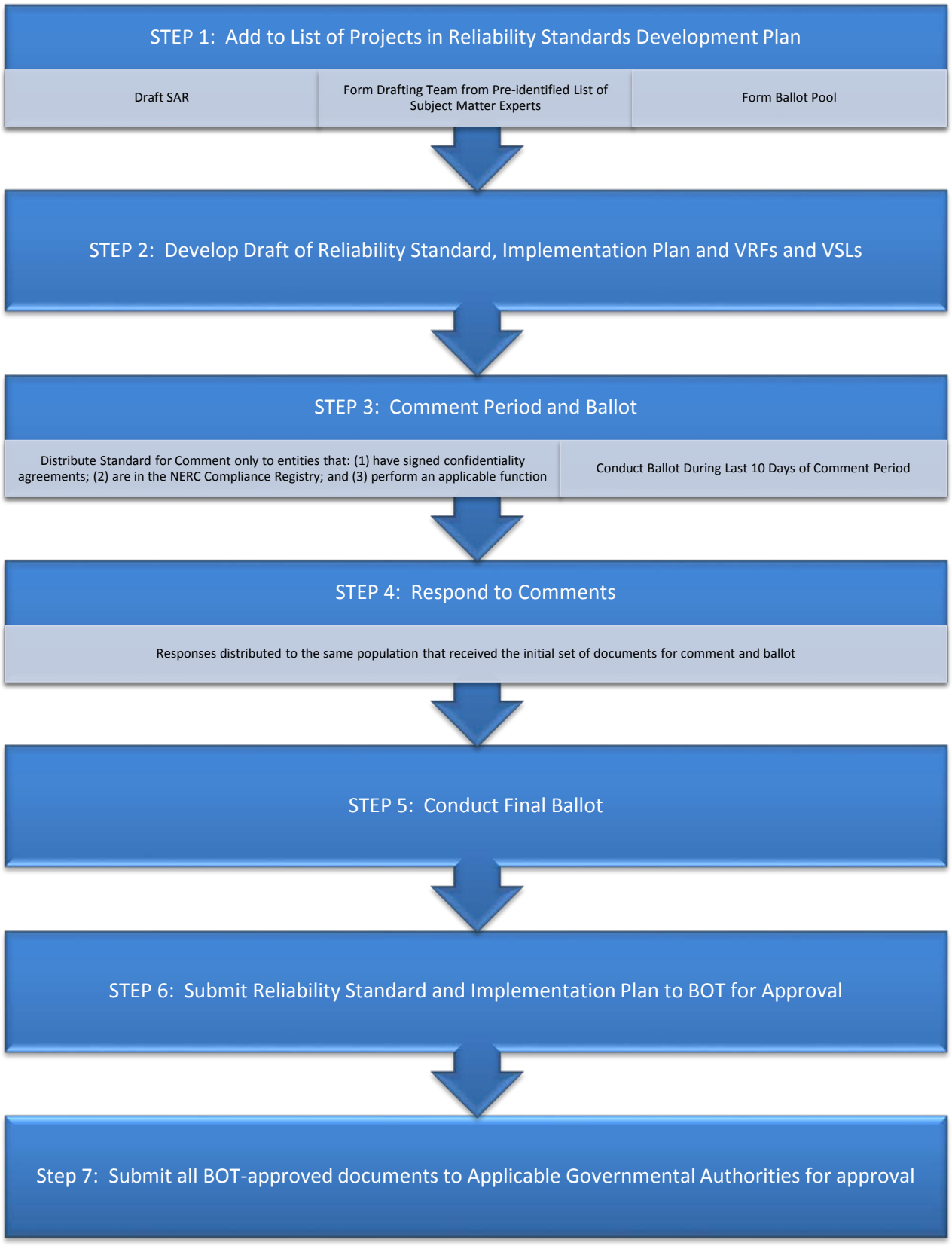


FIGURE 3: Process for Developing a Standard Responsive to an Imminent, Confidential Issue

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.[33] 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.

[33] 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

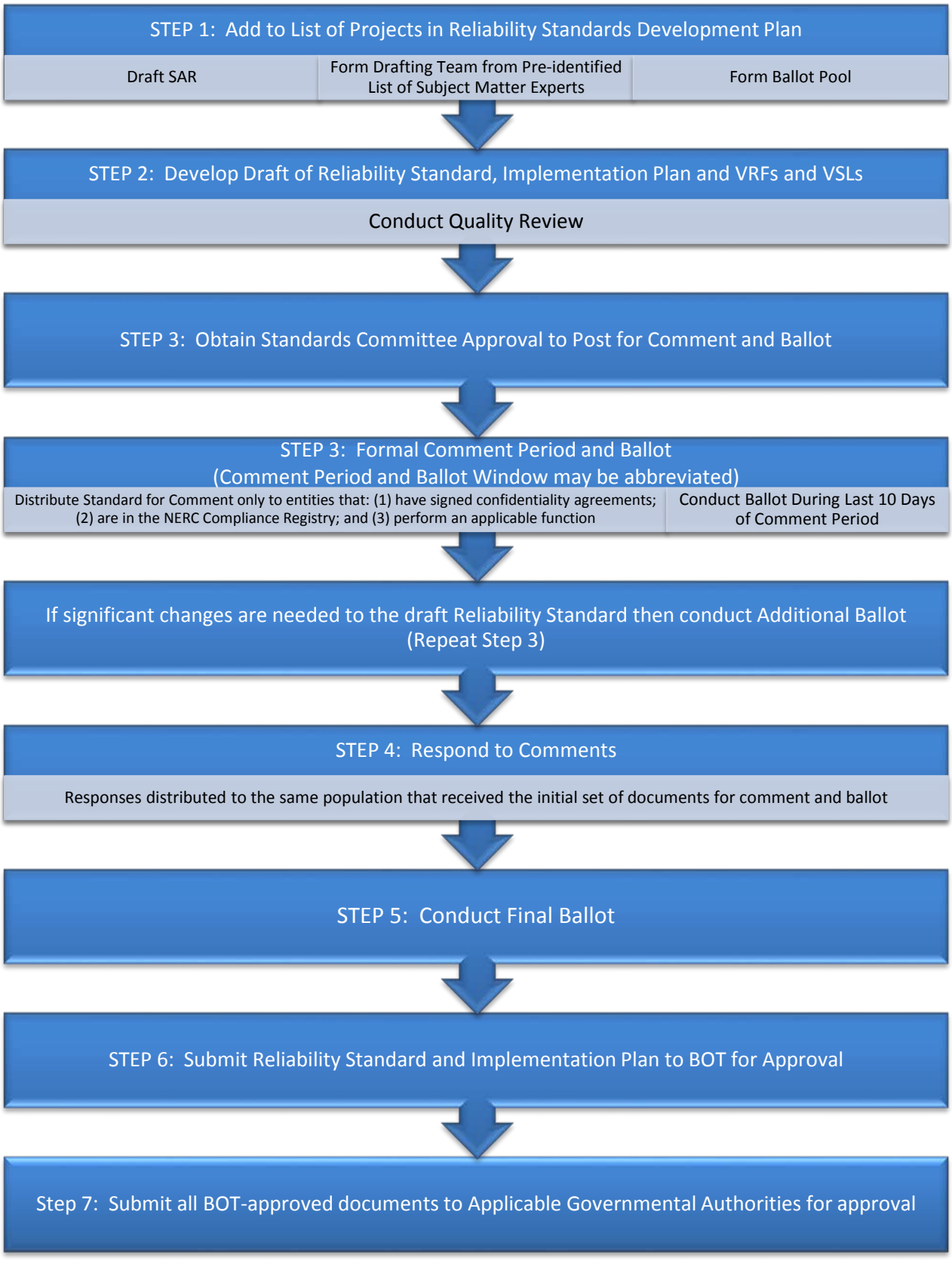


FIGURE 4: Developing a Standard Responsive to a Non-Imminent, Confidential Issue

Section 11.0: Process for Approving Supporting Documents

The NERC Standards Committee oversees the development and approval of documents identified as supporting documents to Reliability Standards approved by the Applicable Governmental Authority. ~~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~~ Supporting documents may explain or facilitate ~~implementation~~ understanding 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.~~ This Section provides the mechanism by which any stakeholder may propose a supporting document to an approved Reliability Standard.

~~The Standards Committee shall authorize the posting of all supporting references[34] 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~~ The process outlined in this section is designed so that each~~that the~~ supporting document ~~has had~~ receives stakeholder review to verify the accuracy of the technical content prior to being posted as a supporting document to an approved Reliability Standard. ~~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.~~

11.1: Types of Supporting Documents

The types of supporting documents that may be approved under this Section are listed below.

Type of Document	Description
Reference	Descriptive, technical information or analysis or explanatory information to support the understanding ~~and interpretation~~ of an approved 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.~~

[34] ~~The Standards Committee's Procedure for Approving the Posting of Reference Documents is posted on the Reliability Standards Resources web page.~~

~~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.~~
Lessons Learned	Documents designed to convey lessons learned related to an approved Reliability Standard. A Lessons Learned document is not intended to establish new Requirements under NERC's Reliability Standards or to modify Requirements in any existing Reliability Standards.
White Paper	An informal paper stating a position or concept. A white paper may have been used to propose preliminary concepts for a Reliability Standard or ~~one of the documents above~~a Reference document.

Supporting documents do not include documents that contain specific compliance approaches or examples of compliance. Such documents would be developed in accordance with the applicable NERC Compliance Monitoring and Enforcement Program process.

11.2: Process for Proposing and Evaluating Supporting Documents

Proposals for supporting documents to approved Reliability Standards shall be submitted to the NERC Reliability Standards Staff.

NERC Staff shall conduct a review of the proposed supporting document. In performing this review, NERC Staff may consult any technical resources it deems appropriate. The purpose of this review is to determine whether the proposed supporting document meets the following three criteria:

1. the document is a type of supporting document subject to this Section, as described in Section 11.1;
2. the document is consistent with the purpose and intent of the associated Reliability Standard; and
3. the document has received adequate stakeholder review to assess its technical adequacy, such as through a NERC technical committee review process, public comment period(s) held during the development of the associated Reliability Standard, or other stakeholder review process.

Where NERC Staff determines that the proposed supporting document has met the three criteria specified above, NERC Staff shall submit the proposed supporting document to the Standards Committee as specified in Section 11.3 below.

Where NERC Staff determines that the proposed supporting document does not meet the first or second criteria specified above, NERC Staff shall notify the submitter that the document will not be posted as a supporting document under this Section. This notification shall be made in writing with an explanation of the basis for the decision. NERC Staff shall also notify the Standards Committee of this determination at the next regularly scheduled Standards Committee meeting.

Where NERC Staff determines that the proposed supporting document meets the first and second criteria, but has not yet received adequate stakeholder review under the third criteria, NERC Staff shall make a recommendation to the Standards Committee to authorize the posting of the proposed supporting document for stakeholder review to verify the accuracy of the technical content. This comment period shall be for 30 days, unless directed otherwise by the Standards Committee. Upon conclusion of the comment period, NERC Staff shall compile the comments and provide to the submitter for consideration. If the submitter

modifies the proposed supporting document based on stakeholder comments, NERC Staff may post the document for additional comment periods to provide for sufficient vetting and technical review.

11.3: Approving a Supporting Document

Following its determination that the proposed supporting document has met the three criteria specified in Section 11.2, NERC Staff shall present the supporting document to the NERC Standards Committee with a recommendation regarding whether the Standards Committee should approve posting the supporting document with the approved Reliability Standard on the pertinent NERC website page(s).

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.[35] 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.

[35] 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

Unofficial Nomination Form

Project 2017-01 Modifications to BAL-003-1.1 Standard Authorization Request Drafting Team

Do not use this form for submitting nominations. Use the electronic form to submit nominations by **8 p.m. Eastern, Wednesday, August 9, 2017.** This unofficial version is provided to assist nominees in compiling the information necessary to submit the electronic form.

Additional information about this project is available on the Project 2017-01 Modifications to BAL-003-1.1 page. If you have questions, contact Senior Standards Developer Darrel Richardson, (via email), or at (609) 613-1848.

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

Previous drafting or review team experience is beneficial, but not required. A brief description of the desired qualifications, expected commitment, and other pertinent information is included below.

Project 2017-01 Modifications to BAL-003-1.1

The purpose of this project is to review the issues identified in the SAR and make corresponding modifications to BAL-003-1.1 as necessary.

Standards affected: BAL-003-1 and BAL-003-1.1

The supporting documents for BAL-003-1.1 were developed using engineering judgment on the data collection and process needed to determine the Interconnection Frequency Response Obligation (IFRO) as well as the processing of raw data to determine compliance. Now that the standard is in place and the data is available for analysis, minor errors in assumptions as well as process inefficiencies have been identified. It was anticipated that as frequency response improves, the approaches embedded in the standard for annual samples may need to be modified. In addition to fixing the inconsistencies identified in the Frequency Response Annual Analysis Report (FRAA), the drafting team may separate the administrative and procedural items and reassign them to an alternative process subject to ERO and NERC Operating Committee approval.

The time commitment for these projects 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 review or drafting team sets forth. Team members may also have side projects, either individually or by subgroup, to present to the larger team for discussion and review. Lastly, an important component of the review and drafting team effort is outreach. Members

of the team will be expected to conduct industry outreach during the development process to support a successful project outcome.

We are seeking a cross section of the industry to participate on the team, but in particular are seeking individuals who have experience and expertise in one or more of the following areas: Reliability Coordinator operations, transmission operations, Balancing Authority operations and generation operations. Experience with developing standards inside or outside (e.g., IEEE, NAESB, ANSI, etc.) of the NERC process is beneficial, but is not required, and should be highlighted in the information submitted, if applicable.

Individuals who have facilitation skills and experience and/or legal or technical writing backgrounds are also strongly desired. Please include this in the description of qualifications as applicable.

Name:	
Organization:	
Address:	
Telephone:	
E-mail:	

Please briefly describe your experience and qualifications to serve on the requested Standard Drafting Team (Bio):

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	

[1] These functions are defined in the NERC Functional Model, which is available on the NERC web site.

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

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:	PER-003-1 Operating Personnel Credentials and PER-004-2 Reliability Coordination — Staffing		
Date Submitted:	TBD		
SAR Requester Information			
Name:	Patti Metro		
Organization:	Chair - Project 2016-EPR-01 PER		
Telephone:	(703) 907-5817	Email:	patti.metro@nreca.coop
SAR Type (Check as many as applicable)			
☐ New Standard		☒ Withdrawal of Existing Standard	
☒ Revision to Existing Standard		☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
Need to add clarity to PER-003-1 that explains that the NERC certifications identified in this standard are described in the NERC System Operator Certification Program. The requirements of PER-004-2 are duplicative with requirements in several other standards that explain in detail the staffing requirements of personnel conducting the Reliability Coordinator function.

SAR Information
Purpose or Goal (How does this request propose to address the problem described above?):
The Project 2016-EPR-01 PER Team recommends that a clarifying footnote be added to PER-003-1 to ensure that stakeholders (now and in the future) understand (i) the connection between the Standard and the Program Manual; and (ii) that the certifications referenced under PER-003-1 are those under the NERC System Operator Certification Program. The Project 2016-EPR-01 PER Team recommends that PER-004-2 be retired.
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
N/A
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The Project 2016-EPR-01 PER team recommends that a clarifying footnote be added to PER-003-1 Requirement R1, R2 and R3 to ensure that stakeholders (now and in the future) understand (i) the connection between the Standard and the Program Manual; and (ii) that the certifications referenced under PER-003-1 are those under the NERC System Operator Certification Program. The PER-004-2 standard falls within Paragraph 81 Criterion B7, because all of its requirements are redundant with requirements in other FERC-approved reliability standards that are in effect or soon to be effective. It is not necessary or efficient to maintain such duplicative requirements. Specifically, PER-004-2's requirements are duplicated in standards: • PER-003-1, R1 • PER-005-2, R2 and R3 • IRO-002-4, R3 and R4 • EOP-004-2, R2 • IRO-008-2, R1, R2, and R4 • IRO-009-2, R1 – R4 • IRO-010-2, R1 – R3 • IRO-014-3, generally • IRO-018-1, R1-R3

SAR Information
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
The Project 2016-EPR-01 PER Team recommends that a clarifying footnote be added to PER-003-1 Requirements R1, R2 and R3 to ensure that stakeholders (now and in the future) understand the connection between the Standard and the Program Manual. The PRT suggests for consideration the following language be used for the footnote "The certifications referenced under PER-003-1 are those under the NERC System Operator Certification Program." Concerning PER-004-2, the standards is duplicative and all requirements are covered in other reliability standards. Specifically, PER-003-1 R1 states that each Reliability Coordinator shall staff its Real-time operating positions with System Operators who have obtained and maintained a valid NERC Reliability Operator certificate. PER-005-2 R1 states that each Reliability Coordinator shall design, develop and deliver training to its System Operators based on a list of Bulk Electric System (BES) company specific Real-time reliability-related tasks. Additionally, PER-005-2 R3 states that Reliability Coordinators have to verify that their personnel are capable of performing each of those tasks. Moreover, in PER-004-2 R1, 24 hours per day, and seven days a week requirements are addressed by several NERC Reliability Standards and Requirements. These requirements cannot be accomplished without an entity having a 24/7 operation. IRO-002-4 R4 (enforceable 4/1/2017) requires that, "Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel…" In addition, IRO-002-4 R3 states that, "Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordination Area." EOP-004-2 covers continuous observation through its reporting timeframes to meet OE-417 for Loss of Monitoring. Additional coverage is ensured through IRO 008-2 R2, "Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address …(SOL) and (IROL) exceedances…" and R4 states, "Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes." Reinforcing the structure of the 24 hours per day, and seven days per week requirement is carried out by IRO-010-2 R1, requiring that Reliability Coordinator's maintain documented specifications for the data to perform Operational Planning analyses, Real-time monitoring, and Real-time Assessments. Real-time is defined as, "Present time as opposed to future times," while Real-time Assessment is defined as "An examination of existing and expected system

SAR Information
conditions, conducted by collecting and reviewing immediately available data." Using these definitions in the Reliability Standards further confirms that PER-004-2 Requirement 1 is duplicative and non-essential as its content is covered in multiple Reliability Standards. PER-004-2 Requirement R2 is duplicated in numerous Reliability Standards justifying the need for retirement of this requirement. As described below, the Standards and requirements of IRO-002-4, IRO-008-2, IRO-009-2, IRO-010-2, IRO-014-3 and IRO-018-1 adequately ensure that protocols are in place to allow the Reliability Coordinator operating personnel to have the best available information at all times. IRO-002-4, R3 states that the Reliability Coordinator shall monitor Facilities and work with neighboring Reliability Coordinator areas to identify SOL and IROL exceedances within its area. In order to ensure compliance with this Standard and Requirement, particular attention must be placed on SOLs, IROLs, and inter-tie facility limits. IRO-008-2 ensures that the Reliability Coordinator performs analyses and assessments to prevent instability, uncontrolled separation, or cascading. R1, R2, and R4 of this Standard specifically require that an Operational Planning Analysis is performed to: • assess whether the planned operations for the next-day will exceed SOLs and IROLs within its Wide Area, • ensure that coordinated plans are developed for the next-day operations to address these exceedances, and • execute Real-time Assessments at least once every 30 minutes. To maintain compliance with the IRO-008-2 Standard, the Reliability Coordinator must place particular attention on SOLs and IROLs. IRO-009-2 builds on IRO-008-2 by ensuring prompt action to prevent or mitigate instances where IROLs are exceeded. Through the Requirements of this Standard, assurances are made that the Reliability Coordinator has one or more Operating Processes, Procedures, or Plans that identify actions to take, or actions to direct others to take, to mitigate the magnitude and duration of an IROL exceedance identified in their Assessments. IRO-010-2 provides data specifications that affords the Reliability Coordinator the specific data necessary to perform its Operational Planning Analyses, Real-time monitoring, Real-time Assessments

SAR Information
and ensures that a protocol exists to resolve any data conflicts. This Standard ensures that the Reliability Coordinator has the best available information at all times to maintain compliance. IRO-014-3 ensures that each Reliability Coordinator's operations are coordinated so that they will not adversely impact other Reliability Coordinator Areas and preserve the reliability benefits of interconnected operations. This Standard again builds on the coordination of the Operational Analyses and Real-time Assessments which requires the Reliability Coordinator to have the best available information at all times to maintain compliance. IRO-018-1 established three requirements for Real-time monitoring and analysis capabilities to support reliable operations. Real-time monitoring involves observing operating status and operating values in Real-time to ensure awareness of system conditions. Through this Standard, processes and procedures are established for evaluating the quality of Real-time data and to provide assurance that any action taken addresses any data quality issues so that Real-time monitoring and Real-time Assessments performed by the Reliability Coordinator contains the best available information at all times.

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

Related SARs	
SAR ID	Explanation
	N/A

Related SARs	

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

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

Periodic Review Template: PER-003-1 Operating Personnel Credentials

December 2016

Introduction

The North American Electric Reliability Corporation (NERC) is required to conduct a periodic review of each NERC Reliability Standard at least once every ten (10) years, or once every five (5) years for Reliability Standards approved by the American National Standards Institute as an American National Standard.[1] The Reliability Standard identified above has been included in the current cycle of periodic reviews. The Review Team shall consist of two (2) subgroups; a Standing Review Team which is appointed annually by the Standards Committee for periodic reviews, and a stakeholder Subject Matter Expert (SME) team.[2] Consistent with Section 13 of the Standards Processes Manual, the Standards Committee may use a public nomination process to appoint the stakeholder SME team, or may use another method to appoint that results in a team that collectively has the necessary technical expertise and work process skills to meet the objectives of the project. The technical experts provide the subject matter expertise and guide the development of the technical aspects of the periodic review, assisted by technical writers, legal and compliance experts. The technical experts maintain authority over the technical details of the periodic review.
Together, the Standing Review Team and SME stakeholder team are the Review Team for a particular periodic review project and complete their portion of the template below.

The purpose of the template is to collect background information, pose questions to guide a comprehensive review of the Standard(s) by the Review Team, and document the Review Team's considerations and recommendations. The Review Team will post the completed template containing its recommendations for information and stakeholder input as required by Section 13 of the NERC Standard Processes Manual.

Review Team Composition

	Standing Review Team	**Plus Section 13 (SMEs):**
Non-CIP Standards	Chairs of the following NERC Standing Committees[3]: • Standards Committee (Also, the SC chair or his/her delegate from the	The Standards Committee will appoint stakeholder subject matter experts for the particular standard(s) being reviewed. The SMEs will work together with the

[1] NERC Standard Processes Manual 45 (2013), posted at http://www.nerc.com/pa/Stand/Documents/Appendix_3A_StandardsProcessesManual.pdf.

[2] Other reliability standards included as part of the Review Team's periodic review were PER-004-2 (included in a separate, concurrent, report) and PER-001-0.2 (which was approved for retirement on March 31, 2017 and therefore not included in either report).

[3] Each committee chair may, at his or her discretion, delegate participation on the Standing Review Team to another member of his or her committee.

	SC will chair the Standing Review Team)[4] • Planning Committee • Operating Committee The Standing Review Team will meet with SMEs and help to ensure a consistent strategy and approach across all of the reviews.	Standing Review Team to conduct its review of the standard(s) and complete the template below.
CIP Standards	Chairs of the following NERC Standing Committees[5]: • Standards Committee (Also, the SC chair or his/her delegate from the SC will chair the Standing Review Team) • CIPC	The Standards Committee will appoint stakeholder subject matter experts for the particular standard(s) being reviewed. The SMEs will work together with the Standing Review Team to conduct its review of the standard(s) and complete the template below.

The Review Team will use the background information and the questions below, along with any associated worksheets or reference documents, to guide a comprehensive review that results in a recommendation from one of the following three (3) choices:

1. Recommend reaffirming the Standard as steady-state (Green); or
2. Recommend that the standard is sufficient to protect reliability and meet the reliability objective of the standard, however there may be future opportunity to improve a non-substantive or insignificant quality and content issue – i.e., continue to monitor (Yellow); or
3. Recommend that the standard needs revision or retirement (Red).

If the team recommends a revision to or a retirement of the Reliability Standard, it must also submit a Standard Authorization Request (SAR) outlining the proposed scope and technical justification for the revision or retirement.

A completed Periodic Review Template and any associated documentation should be submitted by email to Darrel Richardson at darrel.richardson@nerc.net.

[4] The Standards Committee chair may delegate one member of the SC to chair one Standing Review Team's review of a standard s), and another SC member to chair a review of another standard(s).

[5] Each committee chair may, at his or her discretion, delegate participation on the Standing Review Team to another member of his or her committee.

Applicable Reliability Standard: PER-003-1
Team Members (include name and organization): 1. Patti Metro, Nation Rural Electric Cooperative Association 2. Lauri Jones, Pacific Gas and Electric Company 3. Heather Morgan, EDP Renewables North America LLC 4. Jeffrey Sunvick, Western Area Power Administration 5. Jimmy Womack, Southwest Power Pool 6. Brad Perrett, Minnesota Power 7. Carolyn White Wilson, Duke Energy Corporation 8. Michael B. Hoke, PJM Interconnection LLC 9. Danny W. Johnson, Xcel Energy 10. Darrel Richardson, NERC Senior Standards Developer 11. Candice Castaneda, NERC Counsel 12. Michael Brytowski, Great River Energy PMOS Representative
Date Review Completed:

Background Information *(to be completed initially by NERC staff)*

1. Are there any outstanding Federal Energy Regulatory Commission (FERC) directives associated with the Reliability Standard? (*If so, NERC staff will attach a list of the directives with citations to associated FERC orders for inclusion in a SAR.)*

   ☐ Yes

   ☒ No

2. Have stakeholders requested clarity on the Reliability Standard in the form of an (outstanding, in progress, or approved) Interpretation or Compliance Application Notice (CAN)? (*If there are, NERC staff will include a list of the Interpretation(s), CAN(s), or other stakeholder-identified issue(s) that apply to the Reliability Standard*.)

   ☐ Yes

   ☒ No

   Please explain:

3. Is the Reliability Standard one of the most violated Reliability Standards?

☐ Yes

☒ No

If so, does the cause of the frequent violation appear to be a lack of clarity in the language?

☐ Yes

☐ No

Please explain:

Questions for the Review Team

If NERC staff answered "Yes" to any of the questions above, the Reliability Standard probably requires revision. The questions below are intended to further guide your review. Some of the questions reference documents provided by NERC staff as indicated in the Background questions above. Either as a guide to help answer the ensuing questions or as a final check, the Review Team is to use Attachment 3: Independent Expert Evaluation Process.

I. Quality

1. **Reliability Need, Paragraph 81:** Do any of the requirements in the Reliability Standard meet criteria for retirement or modification based on Paragraph 81 concepts? *Use Attachment 2: Paragraph 81 Criteria to make this determination.*

   ☐ Yes

   ☒ No

   Please summarize your application of Paragraph 81 Criteria, if any:

2. **Clarity:** From the Background Information section of this template, has the Reliability Standard been the subject of an Interpretation, CAN or issue associated with it, or is frequently violated because of ambiguity?
   a. Does the Reliability Standard have obviously ambiguous language?
   b. Does the Reliability Standard have language that requires performance that is not measurable?
   c. Are the requirements consistent with the purpose of the Reliability Standard?
   d. Should the requirements stand alone as is, or should they be consolidated with other standards?
   e. Is the Reliability Standard complete and self-contained?
   f. Does the Reliability Standard use consistent terminology?

☒ Yes

☐ No

Please summarize your assessment: Although the response to the parent question above is "No" examination of its subparts (a) – (g) has led the Review Team to recommend a clarifying revision. The Project 2016-EPR-01 PER Review Team recommends that a clarifying footnote be added to PER-003-1 to ensure that stakeholders (now and in the future) understand (i) the connection between the Standard and the NERC System Operator Certification Program Manual; and (ii) that the certifications referenced under PER-003-1 are those under the NERC System Operator Certification Program.

3. **Definitions**: Do any of the defined terms used within the Reliability Standard need to be refined?

☐ Yes

☒ No

Please explain:

4. **Compliance Elements:** Are the compliance elements associated with the requirements (Measures, Data Retention, Violation Risk Factors (VRF), Violation Severity Levels (VSL) and Time Horizons) consistent with the direction of the Reliability Assurance Initiative and FERC and NERC guidelines?

☒ Yes

☐ No

If you answered "No," please identify which elements require revision, and why:

5. **Consistency with Other Reliability Standards:** Does the Reliability Standard need to be revised for formatting and language consistency among requirements within the Reliability Standard, or for coordination with other Reliability Standards?

☐ Yes

☒ No

If you answered "Yes," please describe the changes needed to achieve formatting and language consistency:

6. **Changes in Technology, System Conditions, or other Factors:** Does the Reliability Standard need to be revised to account for changes in technology, system conditions or other factors?

   ☐ Yes

   ☒ No

   If you answered "Yes," please describe the changes and specifically what the potential impact is to reliability if the Reliability Standard is not revised:

7. **Practicable**:
   a. Can the Reliability Standard be practically implemented?

      ☒ Yes

      ☐ No

   b. Is there a concern that it is not cost effective as drafted?

      ☐ Yes

      ☒ No

   Please summarize your assessment of the practicability of the standard:

8. **Consideration of Generator and Transmission Interconnection Facilities:** Is responsibility for generator interconnection Facilities and Transmission Interconnection Facilities appropriately accounted for in the Reliability Standard? **N/A to this standard.**

   ☐ Yes

   ☐ No

   Guiding Questions:

   a. If the Reliability Standard is applicable to Generator Owners and/or Generator Operators, is there any ambiguity about the inclusion of generator Interconnection Facilities? (If generation Interconnection Facilities could be perceived to be excluded, specific language referencing the Facilities should be introduced in the Reliability Standard.)

   b. If the Reliability Standard is not applicable to Generator Owners and/or Generator Operators, is there a reliability-related need for treating generator Interconnection Facilities as Transmission Lines for the purposes of this Reliability Standard? (If so, Generator Owners that own and/or

Generator Operators that operate relevant generator Interconnection Facilities should be explicit in the applicability section of the Reliability Standard.)

c. If the Reliability Standard is applicable to Transmission Operators and/or Distribution Providers, is there any ambiguity about the inclusion of Transmission Interconnection Facilities? (If Transmission Interconnection Facilities could be perceived to be excluded, specific language referencing the Facilities should be introduced in the Reliability Standard.)

9. **Results Based Standard:** Is the Reliability Standard drafted as a results-based standard?

☒ Yes

☐ No

If not, please summarize your assessment:

Guiding Questions:

a. Does the Reliability Standard address performance, risk (prevention) and capability?

☒ Yes

☐ No

b. Does the Reliability Standard follow the RBS format (for example, Requirement and Part structure) in Attachment 1?

☐ Yes

☒ No

c. Does the Reliability Standard follow the Ten Benchmarks of an Excellent Reliability Standard[6]?

☒ Yes

☐ No

II. Content

[6] Ten Benchmarks of an Excellent Reliability Standard, posted at Page 626 of: http://www.nerc.com/pa/Stand/Resources/Documents/DT_Reference_Manual_Resource_Package_080114.pdf

10. **Technical accuracy:** Is the content of the Requirements technically correct, including identifying who does what and when?

    ☒ Yes

    ☐ No

    If not, please summarize your assessment:

11. **Functional Model:** Are the correct functional entities assigned to perform the requirements, consistent with the Functional Model?

    ☒ Yes

    ☐ No

    If not, please summarize your assessment:

12. **Applicability:** Is there a technical justification for revising the applicability of the Reliability Standard, or specific requirements within the standard, to account for differences in reliability risk?

    ☐ Yes

    ☒ No

    If so, please summarize your assessment:

13. **Reliability Gaps:** Are the appropriate actions for which there should be accountability included, or is there a gap?

    ☐ Yes

    ☒ No

    If a gap is identified, please explain:

14. **Technical Quality:** Does the Reliability Standard have a technical basis in engineering and operations?

    ☒ Yes

    ☐ No

    If not, please summarize your assessment:

15. **Does the Reliability Standard reflect a higher solution than the lowest common denominator?**

☒ Yes

☐ No

If not, please summarize your assessment:

16. **Related Regional Reliability Standards**: Is there a related regional Reliability Standard, and is it appropriate to recommend the regional Reliability Standard be retired, appended into the continent-wide standard, or revised in favor of a continent-wide Standard?

☐ Yes

☒ No

If yes, please identify the regional standard(s) and summarize your assessment:

RED, YELLOW GREEN GRADING

Using the questions above, the Review Team shall come to a consensus on whether the Reliability Standard is Green – i.e., affirm as steady-state; Yellow –is sufficient to protect reliability and meet the reliability objective of the standard, however, there may be future opportunity to improve a non-substantive or insignificant quality and content issue – i.e., continue to monitor; or Red - either retire or needs revision, and, thus, a SAR should be developed to process the Standard through the Standards development process for retirement or revision. The reasons for the Review Team's conclusions of Green, Yellow, or Red shall be documented. If a consensus is not reached within the Review Team, minority reviews shall be posted for stakeholder comment, along with the majority opinion on whether the Reliability Standard is Green, Yellow or Red.

Recommendation

The answers to the questions above, along with its Red, Yellow, Green grading and the recommendation of the Review Team, will be posted for a 45-day comment period, and the comments publicly posted. The Review Team will review the comments to evaluate whether to modify its initial recommendation, and will document the final recommendation which will be presented to the Standards Committee.

Preliminary Recommendation (to be completed by the Review Team after its review and prior to posting the results of the review for industry comment):

☐ REAFFIRM *(This should be checked only if there are no outstanding directives, interpretations or issues identified by stakeholders.) GREEN*

☒ REVISE *(The standard is sufficient to protect reliability and meet the reliability objective of the standard, however there may be future opportunity to improve a non-substantive or insignificant quality and content issue.)* (Would include revision of associated RSAW.) *YELLOW*

☐ REVISE *(The recommended revisions are required to support reliability.)* (Would include revision of associated RSAW.) *RED*

☐ RETIRE (Would include revision of associated RSAW.) *RED*

Technical Justification *(If the Review Team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*:

The Project 2016-EPR-01 PER Team recommends that a clarifying footnote be added to PER-003-1 to ensure that stakeholders (now and in the future) understand (i) that the certifications referenced under PER-003-1 are those under the NERC System Operator Certification Program; and (ii) the connection between the Standard and the Program Manual.

Preliminary Recommendation posted for industry comment (date): January 10, 2017

Final Recommendation (to be completed by the Review Team after it has reviewed industry comments on the preliminary recommendation):

☐ REAFFIRM *(This should be checked only if there are no outstanding directives, interpretations or issues identified by stakeholders.) GREEN*

☒ REVISE *(The standard is sufficient to protect reliability and meet the reliability objective of the standard, however there may be future opportunity to improve a non-substantive or insignificant quality and content issue.)* (Would include revision of associated RSAW.) *YELLOW*

☐ REVISE *(The recommended revisions are required to support reliability.)* (Would include revision of associated RSAW.) *RED*

☐ RETIRE (Would include revision of associated RSAW.) *RED*

Technical Justification *(If the Review Team recommends that the Reliability Standard be revised, a draft SAR must be included and the technical justification included in the SAR)*:

The Project 2016-EPR-01 PER Team recommends that a clarifying footnote be added to PER-003-1 to ensure that stakeholders (now and in the future) understand (i) that the certifications referenced under PER-003-1 are those under the NERC System Operator Certification Program; and (ii) the connection between the Standard and the Program Manual.

Date submitted to Standards Committee: June 14, 2017

Attachment 1: Results-Based Standards

Question 9 for the Review Team asks if the Reliability Standard is results-based. The information below will be used by the Review Team in making this determination.

Transitioning the current body of standards into a clear, concise, and effective body will require a comprehensive application of the RBS concept. RBS concepts employ a defense-in-depth strategy for Reliability Standards development where each requirement has a role in preventing system failures, and the roles are complementary and reinforcing. Reliability Standards should be viewed as a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comply with the quality objectives identified in the resource document titled, "Acceptance Criteria of a Reliability Standard."

Accordingly, the Review Team shall consider whether the Reliability Standard contains results-based requirements with sufficient clarity to hold entities accountable without being overly prescriptive as to how a specific reliability outcome is to be achieved. The RBS concept, properly applied, addresses the clarity and effectiveness aspects of a standard.

A Reliability Standard that adheres to the RBS format should strive to achieve a portfolio of performance-, risk-, and competency-based mandatory reliability requirements that support an effective defense-in-depth strategy. Each requirement should identify a clear and measurable expected outcome, such as: a) a stated level of reliability performance, b) a reduction in a specified reliability risk, or c) a necessary competency.

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

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

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

Additionally, each RBS-adherent Reliability Standard should enable or support one or more of the eight reliability principles listed below. Each Reliability Standard should also be consistent with all of the reliability principles.

1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

8. Bulk power systems shall be protected from malicious physical or cyber-attacks.

If the Reliability Standard does not provide for a portfolio of performance-, risk-, and competency-based requirements or consistency with NERC's reliability principles, NERC staff and the Review Team should recommend that the Reliability Standard be revised or reformatted in accordance with the RBS format.

Attachment 2: Paragraph 81 Criteria

The first question for the Review Team asks if one or more of the requirements in the Reliability Standard meet(s) criteria for retirement or modification based on Paragraph 81 concepts.[7] Use the Paragraph 81 criteria explained below to make this determination. Document the justification for the decisions throughout and provide them in the final assessment in the Periodic Review Template.

For a Reliability Standard requirement to be proposed for retirement or modification based on Paragraph 81 concepts, it must satisfy **both**: (i) Criterion A (the overarching criterion); and (ii) at least one of the Criteria B listed below (identifying criteria). In addition, for each Reliability Standard requirement proposed for retirement or modification, the data and reference points set forth below in Criteria C should be considered for making a more informed decision.

Criterion A (Overarching Criterion)

The Reliability Standard requirement requires responsible entities ("entities") to conduct an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.

Section 215(a) (4) of the United States Federal Power Act defines "reliable operation" as: "… operating the elements of the bulk power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements."

Criteria B (Identifying Criteria)

B1. Administrative

The Reliability Standard requirement requires responsible entities to perform a function that is administrative in nature, does not support reliability and is needlessly burdensome.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability and whose retirement or modification will result in an increase in the efficiency of the ERO compliance program. Administrative functions may include a task that is related to developing procedures or plans, such as establishing communication contacts. Thus, for certain requirements, Criterion B1 is closely related to Criteria B2, B3 and B4. Strictly administrative functions do not inherently negatively impact reliability directly and, where possible, should be eliminated or modified for purposes of efficiency and to allow the ERO and entities to appropriately allocate resources.

[7] In most cases, satisfaction of the Paragraph 81 criteria will result in the retirement of a requirement. In some cases, however, there may be a way to modify a requirement so that it no longer satisfies Paragraph 81 criteria. Recognizing that, this document refers to both options.

B2. Data Collection/Data Retention
These are requirements that obligate responsible entities to produce and retain data which document prior events or activities, and should be collected via some other method under NERC's rules and processes.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability. The collection and/or retention of data do not necessarily have a reliability benefit and yet are often required to demonstrate compliance. Where data collection and/or data retention is unnecessary for reliability purposes, such requirements should be retired or modified in order to increase the efficiency of the ERO compliance program.

B3. Documentation
The Reliability Standard requirement requires responsible entities to develop a document (*e.g.,* plan, policy or procedure) which is not necessary to protect reliability of the bulk power system.

This criterion is designed to identify requirements that require the development of a document that is unrelated to reliability or has no performance or results-based function. In other words, the document is required, but no execution of a reliability activity or task is associated with or required by the document.

B4. Reporting
The Reliability Standard requirement obligates responsible entities to report to a Regional Entity, NERC or another party or entity. These are requirements that obligate responsible entities to report to a Regional Entity on activities which have no discernible impact on promoting the reliable operation of the BES and if the entity failed to meet this requirement there would be little reliability impact.

B5. Periodic Updates
The Reliability Standard requirement requires responsible entities to periodically update (*e.g.,* annually) documentation, such as a plan, procedure or policy without an operational benefit to reliability.

This criterion is designed to identify requirements that impose an updating requirement that is out of sync with the actual operations of the BES, unnecessary, or duplicative.

B6. Commercial or Business Practice
The Reliability Standard requirement is a commercial or business practice, or implicates commercial rather than reliability issues.

This criterion is designed to identify those requirements that require: (i) implementing a best or outdated business practice or (ii) implicating the exchange of or debate on commercially sensitive information while doing little, if anything, to promote the reliable operation of the BES.

B7. Redundant
The Reliability Standard requirement is redundant with: (i) another FERC-approved Reliability Standard requirement(s); (ii) the ERO compliance and monitoring program; or (iii) a governmental regulation (*e.g.,* Open Access Transmission Tariff, North American Energy Standards Board ("NAESB"), etc.).

This criterion is designed to identify requirements that are redundant with other requirements and are, therefore, unnecessary. Unlike the other criteria listed in Criterion B, in the case of redundancy, the task or activity itself may contribute to a reliable BES, but it is not necessary to have two duplicative requirements on the same or similar task or activity. Such requirements can be retired or modified with little or no effect on reliability and removal will result in an increase in efficiency of the ERO compliance program.

Criteria C (Additional data and reference points)
Use the following data and reference points to assist in the determination of (and justification for) whether to proceed with retirement or modification of a Reliability Standard requirement that satisfies both Criteria A and B:

C1. Was the Reliability Standard requirement part of a FFT filing?
The application of this criterion involves determining whether the requirement was included in a FFT filing.

C2. Is the Reliability Standard requirement being reviewed in an ongoing Standards Development Project?
The application of this criterion involves determining whether the requirement proposed for retirement or modification is part of an active Standards Development Project, with consideration for the status of the project. If the requirement has been approved by Registered Ballot Body and is scheduled to be presented to the NERC Board of Trustees, in most cases it will not need to be addressed in the periodic review. The exception would be a requirement, such as the Critical Information Protection (CIP) requirements for Version 3 and 4, that is not due to be retired for an extended period of time. Also, for informational purposes, whether the requirement is included in a future or pending Standards Development Project should be identified and discussed.

C3. What is the VRF of the Reliability Standard requirement?
The application of this criterion involves identifying the VRF of the requirement proposed for retirement or modification, with particular consideration of any requirement that has been assigned as having a Medium or High VRF. Also, the fact that a requirement has a Lower VRF is not dispositive that

it qualifies for retirement or modification. In this regard, Criterion C3 is considered in light of Criterion C5 (Reliability Principles) and C6 (Defense in Depth) to ensure that no reliability gap would be created by the retirement or modification of the Lower VRF requirement. For example, no requirement, including a Lower VRF requirement, should be retired or modified if doing so would harm the effectiveness of a larger scheme of requirements that are purposely designed to protect the reliable operation of the BES.

C4. In which tier of the most recent Actively Monitored List (AML) does the Reliability Standard requirement fall?

The application of this criterion involves identifying whether the requirement proposed for retirement or modification is on the most recent AML, with particular consideration for any requirement in the first tier of the AML.

C5. Is there a possible negative impact on NERC's published and posted reliability principles?

The application of this criterion involves consideration of the eight following reliability principles published on the NERC webpage.

Reliability Principles

NERC Reliability Standards are based on certain reliability principles that define the foundation of reliability for North American bulk power systems. Each reliability standard shall enable or support one or more of the reliability principles, thereby ensuring that each standard serves a purpose in support of reliability of the North American bulk power systems. Each reliability standard shall also be consistent with all of the reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence.

Principle 1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

Principle 2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

Principle 3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

Principle 4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

Principle 5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

Principle 6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

Principle 7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

Principle 8. Bulk power systems shall be protected from malicious physical or cyber-attacks. (*footnote omitted*)

C6. Is there any negative impact on the defense in depth protection of the BES?
The application of this criterion considers whether the requirement proposed for retirement or modification is part of a defense in depth protection strategy. In order words, the assessment is to verify whether other requirements rely on the requirement proposed for retirement or modification to protect the BES.

C7. Does the retirement or modification promote results or performance based Reliability Standards?
The application of this criterion considers whether the requirement, if retired or modified, will promote the initiative to implement results- and/or performance-based Reliability Standards.

Attachment 3: Independent Expert Evaluation Process

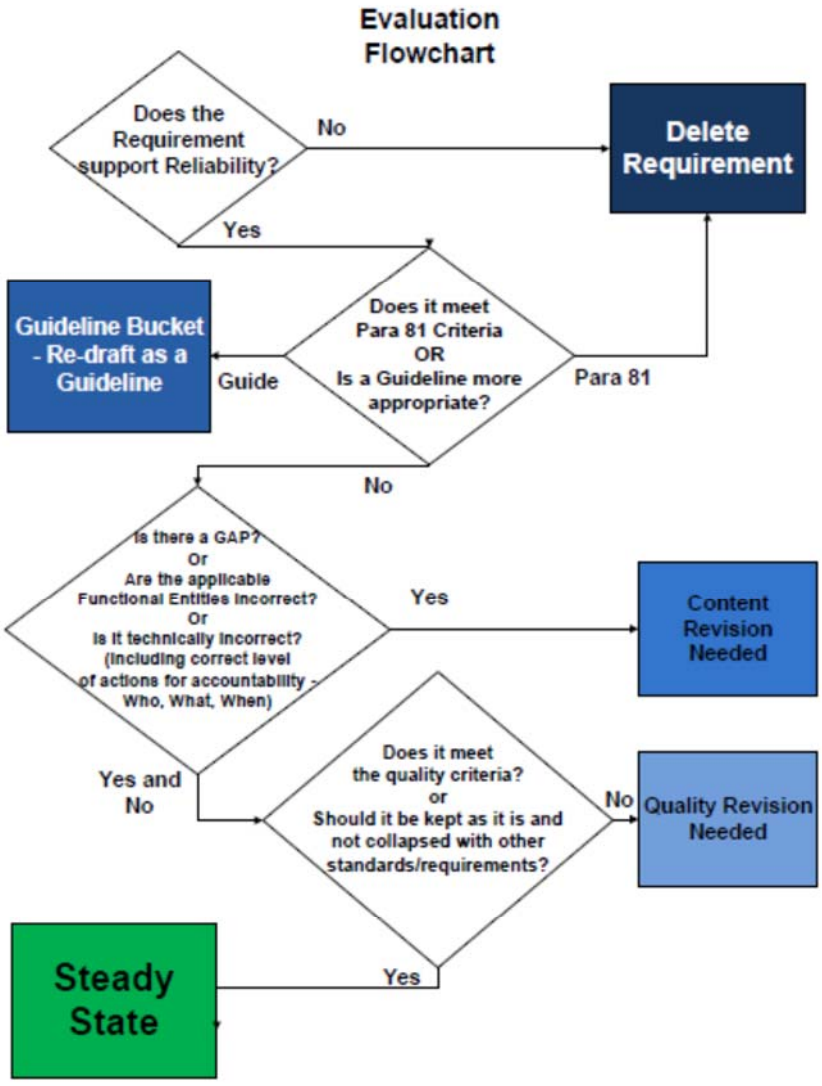


Figure 1: Evaluation Flow Chart

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Periodic Review Template: PER-004-2 Reliability Coordination - Staffing

December 2016

Introduction

The North American Electric Reliability Corporation (NERC) is required to conduct a periodic review of each NERC Reliability Standard at least once every ten (10) years, or once every five (5) years for Reliability Standards approved by the American National Standards Institute as an American National Standard.[1] The Reliability Standard identified above has been included in the current cycle of periodic reviews. The Review Team shall consist of two (2) subgroups; a Standing Review Team which is appointed annually by the Standards Committee for periodic reviews, and a stakeholder Subject Matter Expert (SME) team.[2] Consistent with Section 13 of the Standards Processes Manual, the Standards Committee may use a public nomination process to appoint the stakeholder SME team, or may use another method to appoint that results in a team that collectively has the necessary technical expertise and work process skills to meet the objectives of the project. The technical experts provide the subject matter expertise and guide the development of the technical aspects of the periodic review, assisted by technical writers, legal and compliance experts. The technical experts maintain authority over the technical details of the periodic review.
Together, the Standing Review Team and SME stakeholder team are the Review Team for a particular periodic review project and complete their portion of the template below.

The purpose of the template is to collect background information, pose questions to guide a comprehensive review of the Standard(s) by the Review Team, and document the Review Team's considerations and recommendations. The Review Team will post the completed template containing its recommendations for information and stakeholder input as required by Section 13 of the NERC Standard Processes Manual.

Review Team Composition

	Standing Review Team	**Plus Section 13 (SMEs):**
Non-CIP Standards	Chairs of the following NERC Standing Committees[3]: • Standards Committee (Also, the SC chair or his/her delegate from the	The Standards Committee will appoint stakeholder subject matter experts for the particular standard(s) being reviewed. The SMEs will work together with the

[1] NERC Standard Processes Manual 45 (2013), posted at http://www.nerc.com/pa/Stand/Documents/Appendix_3A_StandardsProcessesManual.pdf.

[2] Other reliability standards included as part of the Review Team's periodic review were PER-003-1 (included in a separate, concurrent, report) and PER-001-0.2 (which was approved for retirement on March 31, 2017 and therefore not included in either report).

[3] Each committee chair may, at his or her discretion, delegate participation on the Standing Review Team to another member of his or her committee.

	SC will chair the Standing Review Team)[4] • Planning Committee • Operating Committee The Standing Review Team will meet with SMEs and help to ensure a consistent strategy and approach across all of the reviews.	Standing Review Team to conduct its review of the standard(s) and complete the template below.
CIP Standards	Chairs of the following NERC Standing Committees[5]: • Standards Committee (Also, the SC chair or his/her delegate from the SC will chair the Standing Review Team) • CIPC	The Standards Committee will appoint stakeholder subject matter experts for the particular standard(s) being reviewed. The SMEs will work together with the Standing Review Team to conduct its review of the standard(s) and complete the template below.

The Review Team will use the background information and the questions below, along with any associated worksheets or reference documents, to guide a comprehensive review that results in a recommendation from one of the following three (3) choices:

1. Recommend reaffirming the Standard as steady-state (Green); or
2. Recommend that the standard is sufficient to protect reliability and meet the reliability objective of the standard, however there may be future opportunity to improve a non-substantive or insignificant quality and content issue – i.e., continue to monitor (Yellow); or
3. Recommend that the standard needs revision or retirement (Red).

If the team recommends a revision to or a retirement of the Reliability Standard, it must also submit a Standard Authorization Request (SAR) outlining the proposed scope and technical justification for the revision or retirement.

A completed Periodic Review Template and any associated documentation should be submitted by email to Darrel Richardson at darrel.richardson@nerc.net.

[4] The Standards Committee chair may delegate one member of the SC to chair one Standing Review Team's review of a standard s), and another SC member to chair a review of another standard(s).

[5] Each committee chair may, at his or her discretion, delegate participation on the Standing Review Team to another member of his or her committee.

Applicable Reliability Standard: PER-004-2
Team Members (include name and organization): 1. Patti Metro, Nation Rural Electric Cooperative Association 2. Lauri Jones, Pacific Gas and Electric Company 3. Heather Morgan, EDP Renewables North America LLC 4. Jeffrey Sunvick, Western Area Power Administration 5. Jimmy Womack, Southwest Power Pool 6. Brad Perrett, Minnesota Power 7. Carolyn White Wilson, Duke Energy Corporation 8. Michael B. Hoke, PJM Interconnection LLC 9. Danny W. Johnson, Xcel Energy 10. Darrel Richardson, NERC Senior Standards Developer 11. Candice Castaneda, NERC Counsel 12. Michael Brytowski, Great River Energy PMOS Representative
Date Review Completed:

Background Information *(to be completed initially by NERC staff)*

1. Are there any outstanding Federal Energy Regulatory Commission (FERC) directives associated with the Reliability Standard? (*If so, NERC staff will attach a list of the directives with citations to associated FERC orders for inclusion in a SAR.)*

   ☐ Yes

   ☒ No

2. Have stakeholders requested clarity on the Reliability Standard in the form of an (outstanding, in progress, or approved) Interpretation or Compliance Application Notice (CAN)? (*If there are, NERC staff will include a list of the Interpretation(s), CAN(s), or other stakeholder-identified issue(s) that apply to the Reliability Standard*.)

   ☐ Yes

   ☒ No

   Please explain:

3. Is the Reliability Standard one of the most violated Reliability Standards?

☐ Yes

☒ No

If so, does the cause of the frequent violation appear to be a lack of clarity in the language?

☐ Yes

☐ No

Please explain:

Questions for the Review Team

If NERC staff answered "Yes" to any of the questions above, the Reliability Standard probably requires revision. The questions below are intended to further guide your review. Some of the questions reference documents provided by NERC staff as indicated in the Background questions above. Either as a guide to help answer the ensuing questions or as a final check, the Review Team is to use Attachment 3: Independent Expert Evaluation Process.

I. Quality

1. **Reliability Need, Paragraph 81:** Do any of the requirements in the Reliability Standard meet criteria for retirement or modification based on Paragraph 81 concepts? *Use Attachment 2: Paragraph 81 Criteria to make this determination.*

   ☒ Yes

   ☐ No

   Please summarize your application of Paragraph 81 Criteria, if any:

   This standard falls within Paragraph 81 Criterion B7, because all of its requirements are redundant with requirements in other FERC-approved reliability standards that are in effect or soon to be effective. It is not necessary or efficient to maintain such duplicative requirements and PER-004-2 may be retired with little to no effect on reliability. Specifically, PER-004-2's requirements are duplicated in standards:

   - PER-003-1, R1
   - PER-005-2, R2 and R3
   - IRO-002-4, R3 and R4
   - EOP-004-2, R2
   - IRO-008-2, R1, R2, and R4
   - IRO-009-2, R1 – R4

- IRO-010-2, R1 – R3
- IRO-014-3, generally
- IRO-018-1, R1-R3

Please refer to Page 10 of this document for a detailed justification for retirement of these requirements.

2. **Clarity:** From the Background Information section of this template, has the Reliability Standard been the subject of an Interpretation, CAN or issue associated with it, or is frequently violated because of ambiguity?
   a. Does the Reliability Standard have obviously ambiguous language?
   b. Does the Reliability Standard have language that requires performance that is not measurable?
   c. Are the requirements consistent with the purpose of the Reliability Standard?
   d. Should the requirements stand alone as is, or should they be consolidated with other standards?
   e. Is the Reliability Standard complete and self-contained?
   f. Does the Reliability Standard use consistent terminology?

   ☐ Yes

   ☒ No

   Please summarize your assessment:

3. **Definitions**: Do any of the defined terms used within the Reliability Standard need to be refined?

   ☐ Yes

   ☒ No

   Please explain:

4. **Compliance Elements:** Are the compliance elements associated with the requirements (Measures, Data Retention, Violation Risk Factors (VRF), Violation Severity Levels (VSL) and Time Horizons) consistent with the direction of the Reliability Assurance Initiative and FERC and NERC guidelines?

   ☒ Yes

   ☐ No

   If you answered "No," please identify which elements require revision, and why:

5. **Consistency with Other Reliability Standards:** Does the Reliability Standard need to be revised for formatting and language consistency among requirements within the Reliability Standard, or for coordination with other Reliability Standards?

   ☐ Yes

   ☒ No

   If you answered "Yes," please describe the changes needed to achieve formatting and language consistency:

6. **Changes in Technology, System Conditions, or other Factors:** Does the Reliability Standard need to be revised to account for changes in technology, system conditions or other factors?

   ☐ Yes

   ☒ No

   If you answered "Yes," please describe the changes and specifically what the potential impact is to reliability if the Reliability Standard is not revised:

7. **Practicable**:
   a. Can the Reliability Standard be practically implemented?

      ☒ Yes

      ☐ No

   b. Is there a concern that it is not cost effective as drafted?

      ☐ Yes

      ☒ No

   Please summarize your assessment of the practicability of the standard:

8. **Consideration of Generator and Transmission Interconnection Facilities:** Is responsibility for generator interconnection Facilities and Transmission Interconnection Facilities appropriately accounted for in the Reliability Standard? **Not Applicable.**

   ☐ Yes

   ☐ No

Guiding Questions:

a. If the Reliability Standard is applicable to Generator Owners and/or Generator Operators, is there any ambiguity about the inclusion of generator Interconnection Facilities? (If generation Interconnection Facilities could be perceived to be excluded, specific language referencing the Facilities should be introduced in the Reliability Standard.)

b. If the Reliability Standard is not applicable to Generator Owners and/or Generator Operators, is there a reliability-related need for treating generator Interconnection Facilities as Transmission Lines for the purposes of this Reliability Standard? (If so, Generator Owners that own and/or Generator Operators that operate relevant generator Interconnection Facilities should be explicit in the applicability section of the Reliability Standard.)

c. If the Reliability Standard is applicable to Transmission Operators and/or Distribution Providers, is there any ambiguity about the inclusion of Transmission Interconnection Facilities? (If Transmission Interconnection Facilities could be perceived to be excluded, specific language referencing the Facilities should be introduced in the Reliability Standard.)

9. **Results Based Standard:** Is the Reliability Standard drafted as a results-based standard?

☒ Yes

☐ No

If not, please summarize your assessment:

Guiding Questions:

a. Does the Reliability Standard address performance, risk (prevention) and capability?

☒ Yes

☐ No

b. Does the Reliability Standard follow the RBS format (for example, Requirement and Part structure) in Attachment 1?

☒ Yes

☐ No

c. Does the Reliability Standard follow the Ten Benchmarks of an Excellent Reliability Standard[6]?

☒ Yes

☐ No

II. Content

10. **Technical accuracy:** Is the content of the Requirements technically correct, including identifying who does what and when?

☒ Yes

☐ No

If not, please summarize your assessment:

11. **Functional Model:** Are the correct functional entities assigned to perform the requirements, consistent with the Functional Model?

☒ Yes

☐ No

If not, please summarize your assessment:

12. **Applicability:** Is there a technical justification for revising the applicability of the Reliability Standard, or specific requirements within the standard, to account for differences in reliability risk?

☐ Yes

☒ No

If so, please summarize your assessment:

13. **Reliability Gaps:** Are the appropriate actions for which there should be accountability included, or is there a gap?

[6] Ten Benchmarks of an Excellent Reliability Standard, posted at Page 626 of: http://www.nerc.com/pa/Stand/Resources/Documents/DT_Reference_Manual_Resource_Package_080114.pdf

☐ Yes

☒ No

If a gap is identified, please explain:

14. **Technical Quality:** Does the Reliability Standard have a technical basis in engineering and operations?

☒ Yes

☐ No

If not, please summarize your assessment:

15. **Does the Reliability Standard reflect a higher solution than the lowest common denominator?**

☒ Yes

☐ No

If not, please summarize your assessment:

16. **Related Regional Reliability Standards**: Is there a related regional Reliability Standard, and is it appropriate to recommend the regional Reliability Standard be retired, appended into the continent-wide standard, or revised in favor of a continent-wide Standard?

☐ Yes

☒ No

If yes, please identify the regional standard(s) and summarize your assessment:

RED, YELLOW GREEN GRADING

Using the questions above, the Review Team shall come to a consensus on whether the Reliability Standard is Green – i.e., affirm as steady-state; Yellow –is sufficient to protect reliability and meet the reliability objective of the standard, however, there may be future opportunity to improve a non-substantive or insignificant quality and content issue – i.e., continue to monitor; or Red - either retire or needs revision, and, thus, a SAR should be developed to process the Standard through the Standards development process for retirement or revision. The reasons for the Review Team's conclusions of Green, Yellow, or Red shall be documented. If a consensus is not reached within the Review Team, minority reviews shall be posted for stakeholder comment, along with the majority opinion on whether the Reliability Standard is Green, Yellow or Red.

Recommendation

The answers to the questions above, along with its Red, Yellow, Green grading and the recommendation of the Review Team, will be posted for a 45-day comment period, and the comments publicly posted. The Review Team will review the comments to evaluate whether to modify its initial recommendation, and will document the final recommendation which will be presented to the Standards Committee.

Preliminary Recommendation (to be completed by the Review Team after its review and prior to posting the results of the review for industry comment):

☐ REAFFIRM *(This should be checked only if there are no outstanding directives, interpretations or issues identified by stakeholders.) GREEN*

☐ REVISE *(The standard is sufficient to protect reliability and meet the reliability objective of the standard, however there may be future opportunity to improve a non-substantive or insignificant quality and content issue.)* (Would include revision of associated RSAW.) *YELLOW*

☐ REVISE *(The recommended revisions are required to support reliability.)* (Would include revision of associated RSAW.) *RED*

☒ RETIRE (Would include revision of associated RSAW.) *RED*

Technical Justification *(If the Review Team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*:

PER-004-2 R1 is duplicative and all requirements are covered in other reliability standards. Specifically, PER-003-1 R1 states that each Reliability Coordinator shall staff its Real-time operating positions with System Operators who have obtained and maintained a valid NERC Reliability Operator certificate. PER-005-2 R1 states that each Reliability Coordinator shall design, develop and deliver training to its System Operators based on a list of Bulk Electric System (BES) company specific Real-time reliability-related tasks. Additionally, PER-005-2 R3 states that Reliability Coordinators have to verify that their personnel are capable of performing each of those tasks.

Moreover, in PER-004-2 R1, 24 hours per day, and seven days a week requirements are addressed by several NERC Reliability Standards and Requirements. These requirements cannot be accomplished without an entity having a 24/7 operation. IRO-002-4 R4 (enforceable 4/1/2017) requires that, "Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel…" In addition, IRO-002-4 R3 states that, "Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordination Area." EOP-004-2 covers continuous observation through its reporting timeframes to

meet OE-417 for Loss of Monitoring. Additional coverage is ensured through IRO 008-2 R2, "Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address …(SOL) and (IROL) exceedances…" and R4 states, "Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes." Reinforcing the structure of the 24 hours per day, and seven days per week requirement is carried out by IRO-010-2 R1, requiring that Reliability Coordinator's maintain documented specifications for the data to perform Operational Planning analyses, Real-time monitoring, and Real-time Assessments. Real-time is defined as, "Present time as opposed to future times," while Real-time Assessment is defined as "An examination of existing and expected system conditions, conducted by collecting and reviewing immediately available data." Using these definitions in the Reliability Standards further confirms that PER-004-2 Requirement 1 is duplicative and non-essential as its content is covered in multiple Reliability Standards.

PER-004-2 Requirement R2 is duplicated in numerous Reliability Standards justifying the need for retirement of this requirement. As described below, the Standards and requirements of IRO-002-4, IRO-008-2, IRO-009-2, IRO-010-2, IRO-014-3 and IRO-018-1 adequately ensure that protocols are in place to allow the Reliability Coordinator operating personnel to have the best available information at all times.

IRO-002-4, R3 states that the Reliability Coordinator shall monitor Facilities and work with neighboring Reliability Coordinator areas to identify SOL and IROL exceedances within its area. In order to ensure compliance with this Standard and Requirement, particular attention must be placed on SOLs, IROLs, and inter-tie facility limits.

IRO-008-2 ensures that the Reliability Coordinator performs analyses and assessments to prevent instability, uncontrolled separation, or cascading. R1, R2, and R4 of this Standard specifically require that an Operational Planning Analysis is performed to:

- assess whether the planned operations for the next-day will exceed SOLs and IROLs within its Wide Area,
- ensure that coordinated plans are developed for the next-day operations to address these exceedances, and
- execute Real-time Assessments at least once every 30 minutes.

To maintain compliance with the IRO-008-2 Standard, the Reliability Coordinator must place particular attention on SOLs and IROLs.

IRO-009-2 builds on IRO-008-2 by ensuring prompt action to prevent or mitigate instances where IROLs are exceeded. Through the Requirements of this Standard, assurances are made that the Reliability Coordinator has one or more Operating Processes, Procedures, or Plans that identify actions to take, or

actions to direct others to take, to mitigate the magnitude and duration of an IROL exceedance identified in their Assessments.

IRO-010-2 provides data specifications that affords the Reliability Coordinator the specific data necessary to perform its Operational Planning Analyses, Real-time monitoring, Real-time Assessments and ensures that a protocol exists to resolve any data conflicts. This Standard ensures that the Reliability Coordinator has the best available information at all times to maintain compliance.

IRO-014-3 ensures that each Reliability Coordinator's operations are coordinated so that they will not adversely impact other Reliability Coordinator Areas and preserve the reliability benefits of interconnected operations. This Standard again builds on the coordination of the Operational Analyses and Real-time Assessments which requires the Reliability Coordinator to have the best available information at all times to maintain compliance.

IRO-018-1 established three requirements for Real-time monitoring and analysis capabilities to support reliable operations. Real-time monitoring involves observing operating status and operating values in Real-time to ensure awareness of system conditions. Through this Standard, processes and procedures are established for evaluating the quality of Real-time data and to provide assurance that any action taken addresses any data quality issues so that Real-time monitoring and Real-time Assessments performed by the Reliability Coordinator contains the best available information at all times.

Preliminary Recommendation posted for industry comment (date): January 10, 2017

Final Recommendation (to be completed by the Review Team after it has reviewed industry comments on the preliminary recommendation):

☐ REAFFIRM *(This should be checked only if there are no outstanding directives, interpretations or issues identified by stakeholders.) GREEN*

☐ REVISE *(The standard is sufficient to protect reliability and meet the reliability objective of the standard, however there may be future opportunity to improve a non-substantive or insignificant quality and content issue.)* (Would include revision of associated RSAW.) *YELLOW*

☐ REVISE *(The recommended revisions are required to support reliability.)* (Would include revision of associated RSAW.) *RED*

☒ RETIRE (Would include revision of associated RSAW.) *RED*

Technical Justification *(If the Review Team recommends that the Reliability Standard be revised, a draft SAR must be included and the technical justification included in the SAR)*:

See justification above.

Date submitted to Standards Committee: June 14, 2017

Attachment 1: Results-Based Standards

Question 9 for the Review Team asks if the Reliability Standard is results-based. The information below will be used by the Review Team in making this determination.

Transitioning the current body of standards into a clear, concise, and effective body will require a comprehensive application of the RBS concept. RBS concepts employ a defense-in-depth strategy for Reliability Standards development where each requirement has a role in preventing system failures, and the roles are complementary and reinforcing. Reliability Standards should be viewed as a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comply with the quality objectives identified in the resource document titled, "Acceptance Criteria of a Reliability Standard."

Accordingly, the Review Team shall consider whether the Reliability Standard contains results-based requirements with sufficient clarity to hold entities accountable without being overly prescriptive as to how a specific reliability outcome is to be achieved. The RBS concept, properly applied, addresses the clarity and effectiveness aspects of a standard.

A Reliability Standard that adheres to the RBS format should strive to achieve a portfolio of performance-, risk-, and competency-based mandatory reliability requirements that support an effective defense-in-depth strategy. Each requirement should identify a clear and measurable expected outcome, such as: a) a stated level of reliability performance, b) a reduction in a specified reliability risk, or c) a necessary competency.

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

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

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

Additionally, each RBS-adherent Reliability Standard should enable or support one or more of the eight reliability principles listed below. Each Reliability Standard should also be consistent with all of the reliability principles.

1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

8. Bulk power systems shall be protected from malicious physical or cyber-attacks.

If the Reliability Standard does not provide for a portfolio of performance-, risk-, and competency-based requirements or consistency with NERC's reliability principles, NERC staff and the Review Team should recommend that the Reliability Standard be revised or reformatted in accordance with the RBS format.

Attachment 2: Paragraph 81 Criteria

The first question for the Review Team asks if one or more of the requirements in the Reliability Standard meet(s) criteria for retirement or modification based on Paragraph 81 concepts.[7] Use the Paragraph 81 criteria explained below to make this determination. Document the justification for the decisions throughout and provide them in the final assessment in the Periodic Review Template.

For a Reliability Standard requirement to be proposed for retirement or modification based on Paragraph 81 concepts, it must satisfy **both**: (i) Criterion A (the overarching criterion); and (ii) at least one of the Criteria B listed below (identifying criteria). In addition, for each Reliability Standard requirement proposed for retirement or modification, the data and reference points set forth below in Criteria C should be considered for making a more informed decision.

Criterion A (Overarching Criterion)

The Reliability Standard requirement requires responsible entities ("entities") to conduct an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.

Section 215(a) (4) of the United States Federal Power Act defines "reliable operation" as: "… operating the elements of the bulk power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements."

Criteria B (Identifying Criteria)

B1. Administrative

The Reliability Standard requirement requires responsible entities to perform a function that is administrative in nature, does not support reliability and is needlessly burdensome.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability and whose retirement or modification will result in an increase in the efficiency of the ERO compliance program. Administrative functions may include a task that is related to developing procedures or plans, such as establishing communication contacts. Thus, for certain requirements, Criterion B1 is closely related to Criteria B2, B3 and B4. Strictly administrative functions do not inherently negatively impact reliability directly and, where possible, should be eliminated or modified for purposes of efficiency and to allow the ERO and entities to appropriately allocate resources.

[7] In most cases, satisfaction of the Paragraph 81 criteria will result in the retirement of a requirement. In some cases, however, there may be a way to modify a requirement so that it no longer satisfies Paragraph 81 criteria. Recognizing that, this document refers to both options.

B2. Data Collection/Data Retention
These are requirements that obligate responsible entities to produce and retain data which document prior events or activities, and should be collected via some other method under NERC's rules and processes.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability. The collection and/or retention of data do not necessarily have a reliability benefit and yet are often required to demonstrate compliance. Where data collection and/or data retention is unnecessary for reliability purposes, such requirements should be retired or modified in order to increase the efficiency of the ERO compliance program.

B3. Documentation
The Reliability Standard requirement requires responsible entities to develop a document (*e.g.,* plan, policy or procedure) which is not necessary to protect reliability of the bulk power system.

This criterion is designed to identify requirements that require the development of a document that is unrelated to reliability or has no performance or results-based function. In other words, the document is required, but no execution of a reliability activity or task is associated with or required by the document.

B4. Reporting
The Reliability Standard requirement obligates responsible entities to report to a Regional Entity, NERC or another party or entity. These are requirements that obligate responsible entities to report to a Regional Entity on activities which have no discernible impact on promoting the reliable operation of the BES and if the entity failed to meet this requirement there would be little reliability impact.

B5. Periodic Updates
The Reliability Standard requirement requires responsible entities to periodically update (*e.g.,* annually) documentation, such as a plan, procedure or policy without an operational benefit to reliability.

This criterion is designed to identify requirements that impose an updating requirement that is out of sync with the actual operations of the BES, unnecessary, or duplicative.

B6. Commercial or Business Practice
The Reliability Standard requirement is a commercial or business practice, or implicates commercial rather than reliability issues.

This criterion is designed to identify those requirements that require: (i) implementing a best or outdated business practice or (ii) implicating the exchange of or debate on commercially sensitive information while doing little, if anything, to promote the reliable operation of the BES.

B7. Redundant
The Reliability Standard requirement is redundant with: (i) another FERC-approved Reliability Standard requirement(s); (ii) the ERO compliance and monitoring program; or (iii) a governmental regulation (*e.g.,* Open Access Transmission Tariff, North American Energy Standards Board ("NAESB"), etc.).

This criterion is designed to identify requirements that are redundant with other requirements and are, therefore, unnecessary. Unlike the other criteria listed in Criterion B, in the case of redundancy, the task or activity itself may contribute to a reliable BES, but it is not necessary to have two duplicative requirements on the same or similar task or activity. Such requirements can be retired or modified with little or no effect on reliability and removal will result in an increase in efficiency of the ERO compliance program.

Criteria C (Additional data and reference points)
Use the following data and reference points to assist in the determination of (and justification for) whether to proceed with retirement or modification of a Reliability Standard requirement that satisfies both Criteria A and B:

C1. Was the Reliability Standard requirement part of a FFT filing?
The application of this criterion involves determining whether the requirement was included in a FFT filing.

C2. Is the Reliability Standard requirement being reviewed in an ongoing Standards Development Project?
The application of this criterion involves determining whether the requirement proposed for retirement or modification is part of an active Standards Development Project, with consideration for the status of the project. If the requirement has been approved by Registered Ballot Body and is scheduled to be presented to the NERC Board of Trustees, in most cases it will not need to be addressed in the periodic review. The exception would be a requirement, such as the Critical Information Protection (CIP) requirements for Version 3 and 4, that is not due to be retired for an extended period of time. Also, for informational purposes, whether the requirement is included in a future or pending Standards Development Project should be identified and discussed.

C3. What is the VRF of the Reliability Standard requirement?
The application of this criterion involves identifying the VRF of the requirement proposed for retirement or modification, with particular consideration of any requirement that has been assigned as having a Medium or High VRF. Also, the fact that a requirement has a Lower VRF is not dispositive that

it qualifies for retirement or modification. In this regard, Criterion C3 is considered in light of Criterion C5 (Reliability Principles) and C6 (Defense in Depth) to ensure that no reliability gap would be created by the retirement or modification of the Lower VRF requirement. For example, no requirement, including a Lower VRF requirement, should be retired or modified if doing so would harm the effectiveness of a larger scheme of requirements that are purposely designed to protect the reliable operation of the BES.

C4. In which tier of the most recent Actively Monitored List (AML) does the Reliability Standard requirement fall?

The application of this criterion involves identifying whether the requirement proposed for retirement or modification is on the most recent AML, with particular consideration for any requirement in the first tier of the AML.

C5. Is there a possible negative impact on NERC's published and posted reliability principles?

The application of this criterion involves consideration of the eight following reliability principles published on the NERC webpage.

Reliability Principles

NERC Reliability Standards are based on certain reliability principles that define the foundation of reliability for North American bulk power systems. Each reliability standard shall enable or support one or more of the reliability principles, thereby ensuring that each standard serves a purpose in support of reliability of the North American bulk power systems. Each reliability standard shall also be consistent with all of the reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence.

Principle 1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

Principle 2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

Principle 3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

Principle 4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

Principle 5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

Principle 6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

Principle 7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

Principle 8. Bulk power systems shall be protected from malicious physical or cyber-attacks. (*footnote omitted*)

C6. Is there any negative impact on the defense in depth protection of the BES?
The application of this criterion considers whether the requirement proposed for retirement or modification is part of a defense in depth protection strategy. In order words, the assessment is to verify whether other requirements rely on the requirement proposed for retirement or modification to protect the BES.

C7. Does the retirement or modification promote results or performance based Reliability Standards?
The application of this criterion considers whether the requirement, if retired or modified, will promote the initiative to implement results- and/or performance-based Reliability Standards.

Attachment 3: Independent Expert Evaluation Process

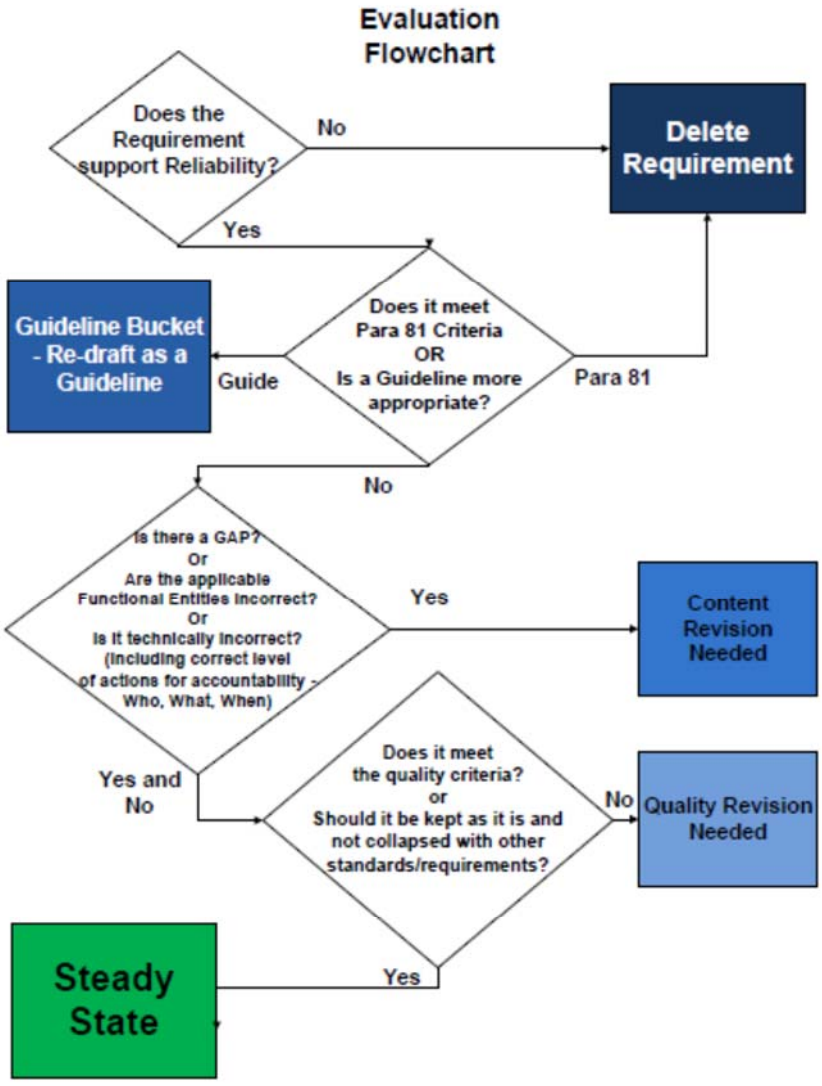


Figure 1: Evaluation Flow Chart

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Unofficial Nomination Form

Project 2017-06 Modifications to BAL-002-2 Standards Authorization Request Drafting Team

Do not use this form for submitting nominations. Use the electronic form to submit nominations by **8 p.m. Eastern, Wednesday, August 9, 2017.** This unofficial version is provided to assist nominees in compiling the information necessary to submit the electronic form.

Additional information about this project is available on the Project 2017-06 Modifications to BAL-002-2 page. If you have questions, contact Senior Standards Developer Darrel Richardson, (via email), or at (609) 613-1848.

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

Previous drafting or periodic review team experience is beneficial, but not required. A brief description of the desired qualifications, expected commitment, and other pertinent information is included below.

Project 2017-06 Modifications to BAL-002-2

The primary goal of this SAR is to allow the standard drafting team (SDT) for Project 2017-06, Disturbance Control to modify standard BAL-002-2 to address the directives of the January 19, 2017 FERC Order, and to ensure consistency within the NERC body of Reliability Standards.

On January 19, 2017, FERC issued an order directing the ERO to develop modifications to standard BAL-002-2 to address their concerns regarding the 15-minute recovery period set forth in Requirement R1. In the order, FERC stated:

> "Accordingly, we direct NERC to develop modifications to Reliability Standard BAL-002-2, Requirement R1 to require Balancing Authorities (BA) or Reserve Sharing Groups (RSG): (1) to notify the reliability coordinator of the conditions set forth in Requirement R1, Part 1.3.1 preventing it from complying with the 15-minute ACE recovery period; and (2) to provide the reliability coordinator with its ACE recovery plan, including a target recovery time. NERC may also propose an equally efficient and effective alternative."

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 review or drafting team sets forth. Team members may also have side projects, either individually or by subgroup, to present to the larger team for discussion and review. Lastly, an important component of the review and drafting team effort is outreach. Members of the team will be expected to conduct industry outreach during the development process to support a successful project outcome.

We are seeking a cross section of the industry to participate on the team, but in particular are seeking individuals who have experience and expertise in one or more of the following areas: Reliability Coordinator operations, transmission operations, Balancing Authority operations and generation operations. Experience with developing standards inside or outside (e.g., IEEE, NAESB, ANSI, etc.) of the NERC process is beneficial, but is not required, and should be highlighted in the information submitted, if applicable.

Individuals who have facilitation skills and experience and/or legal or technical writing backgrounds are also strongly desired. Please include this in the description of qualifications as applicable.

Standards affected: BAL-002-2

Name:	
Organization:	
Address:	
Telephone:	
E-mail:	
Please briefly describe your experience and qualifications to serve on the requested Standard Drafting Team (Bio):	
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	

[1] These functions are defined in the NERC Functional Model, which is available on the NERC web site.

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

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Impacted by the Retirement of FAC-010-3

Project 2015-09 Establish and Communicate System Operating Limits

STD	Standard Reference	Comment / Proposed Action
BAL standards		No Action Required
CIP standards		
CIP-002-5.1a	Attachment 1: 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.	This reference directly refers to the Planning Coordinator (PC), Transmission Planner (TP), and Reliability Coordinator (RC) and certain facilities that have been identified by these entities as being critical to the derivation of an IROL. After retirement of FAC-10-3, PCs and TPs will no longer be required to establish IROLs using FAC-010-3; however, IROLs will continue to be required to be established by the RC. Similar to Requirement R2, Part 2.6 of Attachment 1 of CIP-002-5.1a, FAC-014-3, Requirement R6, requires the Facilities (generation and/or transmission) identified by the RC as critical to the derivation of the IROL to be communicated to the Generator Owners (GO) and Transmission Owners (TOs). FAC-014-3 Requirement R6 specifically states, “Each Reliability Coordinator that is impacted by an IROL shall provide Transmission Owners and Generation Owners within its Reliability Coordinator Area a

		list of Facilities owned by that entity that are critical to the derivation of the IROL." While Requirement R2, Part 2.6 of Attachment 1 of CIP-002-5.1a could benefit from a revision to eliminate the PC and TP in response to the retirement of FAC-010-3, no reliability gap is created if FAC-010-3 is retired prior to the revision of Requirement R2, Part 2.6 of Attachment 1 given the above requirements for the RC. Consideration should also be given to modify Requirement R2, Part 2.6 of Attachment 1 of CIP-002-5.1a to focus on identification of Facilities – not the identification of IROLs as the limits themselves are immaterial to the goal. Accordingly, it may be appropriate for the Facilities identified as applicable to the CIP standard include due consideration for those planning events that result in System instability, Cascading, or uncontrolled separation as identified in the PC and TP's Planning Assessment for the Near-Term Transmission Planning Horizon. **Recommendations:** Revise Requirement R2, Part 2.6 of Attachment 1 in response to the retirement of FAC-010-3 to eliminate PC and TP responsibility for identification of Facilities critical to the derivation of IROLs. A future team should determine the appropriate Facilities for application of the CIP standard and include due consideration for those planning events that result in System instability, Cascading, or uncontrolled separation as identified in the PC and TP's

		Planning Assessment for the Near-Term Transmission Planning Horizon.
CIP-014-2	Applicability 4.1.1.3 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.	This reference directly refers to the PC and TP (and RC) and certain facilities that have been identified by these entities as being critical to the derivation of an IROL. Similar to 4.1.1.3 of the Applicability section of CIP-014-2, FAC-014-3, Requirement R6 requires the Facilities (generation and/or transmission) identified by the RC as critical to the derivation of the IROL to be communicated to the GOs and TOs. FAC-014-3 Requirement R6 specifically states, "Each Reliability Coordinator that is impacted by an IROL shall provide Transmission Owners and Generation Owners within its Reliability Coordinator Area a list of Facilities owned by that entity that are critical to the derivation of the IROL." While 4.1.1.3 of the Applicability section of CIP-014-2 could benefit from a revision to eliminate the PC and TP in response to the retirement of FAC-010-3, no reliability gap is created if FAC-010-3 is retired prior to the revision of Requirement R2, Part 2.6 of Attachment 1 given the above requirements for the RC. Consideration should also be given to modifying 4.1.1.3 of the Applicability section of CIP-014-2 to focus on identification of Facilities – not the identification of IROLs as the limits themselves are immaterial to the goal. Accordingly, it may be appropriate for the Facilities identified as applicable to the CIP standard include due consideration for those planning events that result in System instability, Cascading, or uncontrolled separation as identified in

		the PC and TP's Planning Assessment for the Near-Term Transmission Planning Horizon. **Recommendations:** Revise 4.1.1.3 of the Applicability section of CIP-014-2 in response to the retirement of FAC-010-3 to eliminate the PC and TP responsibility for identification of Facilities critical to the derivation of IROLs. A future team should determine the appropriate Facilities for application of the CIP standard and include due consideration for those planning events that result in System instability, Cascading, or uncontrolled separation as identified in the PC and TP's Planning Assessment for the Near-Term Transmission Planning Horizon.
COM standards		No Action Required
EOP standards		No Action Required
FAC standards		
FAC-003-4	**Introduction:** **4.2.2.** Each overhead transmission line operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator. **4.3.1.2.** Operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator; or …	The Applicability section of the Introduction specifies "applicable lines" and includes overhead transmission lines (< 200 kV) identified as an element of an IROL by the PC. Requirements R1 and R2 reference "applicable lines" and IROLs as well. "Applicable lines" are specified for the identification of overhead transmission lines that require the levels of vegetation management required by the standard. All overhead transmission lines that operate at 200 kV and above are included as "applicable

	Requirements **R1.** Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the Minimum Vegetation Clearance Distance (MVCD) of its applicable line(s) which are either an element of an IROL, or an element of a Major WECC Transfer Path; operating within their Rating and all Rated Electrical Operating Conditions of the types shown below… **R2.** Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are not either an element of an IROL, or an element of a Major WECC Transfer Path.	lines" (4.2.1). Qualifications are then being made to include < 200 kV transmission lines (4.2.2 & 4.2.3) that have a high enough level of criticality to require the same vegetative management requirements as higher voltage transmission lines. The actual limit is not the focus, but rather, the identification of transmission lines that, when compromised, present the risk of potentially severe consequences and therefore should be subject to stricter vegetation management. The retirement of FAC-010 does not create a reliability gap here. The language in Parts 4.2.2 and 4.3.1.2 of FAC-003-4 specifically addresses IROLs determined in the planning horizon pursuant to FAC-014; however, IROLs are required to be established by the RC, and the Facilities critical to the derivation of the IROL are communicated to the GOs and TOs through FAC-014-3, Requirement R6 which states, "Each Reliability Coordinator that is impacted by an IROL shall provide Transmission Owners and Generation Owners within its Reliability Coordinator Area a list of Facilities owned by that entity that are critical to the derivation of the IROL." FAC-003-4 is applicable to GOs and TOs. Accordingly, these entities are made aware of IROLs and the facilities critical to the derivation of those IROLs from the RC as per FAC-014-3 Requirement R6 above. While Parts 4.2.2 and 4.3.1.2 of the Applicability section of FAC-003-4 would benefit from a revision in response to the retirement of FAC-010, no reliability gap is created if FAC-010-3 is retired

		prior to the revision of these subparts given the above requirements for the RC. **Recommendations:** Revise 4.2.2 and 4.3.1.2 of the Applicability section of FAC-003-4 in response to the retirement of FAC-010-3 to eliminate references to the PC determining IROLs. A future team should determine the appropriateness for the elements identified as applicable to 4.2.2 and 4.3.1.2 of the Applicability section of FAC-003-4 include due consideration for those planning events that result in System instability, Cascading, or uncontrolled separation as identified in the PC and TP's Planning Assessment for the Near-Term Transmission Planning Horizon.
FAC-013-2	**Requirements** **R1.2.** A statement that the assessment shall respect known System Operating Limits (SOLs).	R 1.2 is not specific to Planning Horizon SOLs but the applicability of the overall standard is for PCs. The retirement of FAC-010-3 does not create a reliability gap here as SOLs will continue to be established by TOPs and communicated to PCs through FAC-014-3 Requirement R5. The PC can then use the SOL information to satisfy Requirement R1, R1.2. Requirement R1.2 does not specify whether the SOLs are sourced from the RC or by the PC. **Recommendations:** Consideration should also be given to clarify FAC-013-2 Requirement R1.2 to eliminate the use of the SOL term as applied to the Planning Coordinators Transfer Capability assessment.

		Possible solutions include changing the language of Requirement R1, R1.2 to reference the performance requirements per Table 1 of TPL-001-4, or revising the language to replace SOL with "Facility Ratings, System steady-state voltage limits, and the Transmission Planners' stability criteria." A future team should consider eliminating the use of the SOL term as applied to the Planning Coordinators Transfer Capability assessment as described above.
FAC-014-2	Requirements R3 – R5	Under Revision
INT standards		No Action Required
IRO standards		No Action Required
MOD standards		No Action Required
NUC standards		No Action Required
PER standards		No Action Required
PRC standards		
PRC-002-2	**Requirements:** **R5.** Each Responsible Entity shall: **5.1.** Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following: **5.1.2.** Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL).	Direct language around SOL and IROL does not specify PC SOL methodology and therefore does not preclude the RC's methodology from determining the applicable limits. However, the time horizon for the requirement is "long-term planning." Additionally, the SOLs referred to are stability based only. The retirement of FAC-010-3 does not create a reliability gap here. IROLs and stability-related SOLs are communicated to the GOs

	5.1.4. One or more BES Elements that are part of an Interconnection Reliability Operating Limit (IROL).	and TOs through FAC-014-3, Requirement R6 which states, "Each Reliability Coordinator that is impacted by an IROL shall provide Transmission Owners and Generation Owners within its Reliability Coordinator Area a list of Facilities owned by that entity that are critical to the derivation of the IROL." The Applicability section of PRC-002-2 describes the Responsibly Entities: 4.1.1 Eastern Interconnection – Planning Coordinator 4.1.2 ERCOT Interconnection – Planning Coordinator or Reliability Coordinator 4.1.3 Western Interconnection – Reliability Coordinator 4.1.4 Quebec Interconnection – Planning Coordinator or Reliability Coordinator Regardless of the designation of the Responsible Entity in a given Interconnection, either is able to provide the GOs and TOs the information in Requirement R5, Parts 5.1.2 and 5.1.4. The information is ultimately sourced from the RC, but FAC-014-3, Requirement R5, Parts 5.1, 5.2, and subparts requires the RC to communicate the relevant information to the PC, who, in turn, can communicate the information to the applicable GO and TO as required by PRC-002-2, Requirement R5, Parts 5.1.2 and 5.1.4. FAC-014-3 R5. Each Reliability Coordinator shall provide:

		5.1. Each Planning Coordinator within its RC Area, SOLs for its RC Area (including the subset of SOLs that are IROLs) at least once every twelve calendar months. 5.2. Each impacted Planning Coordinator the following information for each established stability limit and each established IROL at least once every twelve calendar months: 5.2.1. The value of the stability limit or IROL; 5.2.2. Identification of the Facilities that are critical to the derivation of the stability limit or IROL; 5.2.3. The associated IROL Tv for any IROL; 5.2.4. The associated Contingency(ies); and, 5.2.5. The type of limitation represented by the stability limit or IROL (e.g., voltage collapse, angular stability). While subparts 5.1.2 and 5.1.4 of PRC-002-2 would benefit from a revision in response to the retirement of FAC-010, the need for such a revision does not rise to the level of creating a reliability gap if FAC-010 is retired prior to the time these requirements can be changed. **Recommendations:** It is recommended that this standard be modified at some point in the future to update the designation of the Responsible Entities defined in the Standard. In the absence of this change, however, the currently defined Responsible Entities are capable of providing the necessary information through the mechanisms described above.
PRC-023-4	**Attachment B** - Criteria Section:	Direct reference to FAC-010 made in this attachment.

	If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit… B2. The circuit is a monitored Facility of an Interconnection Reliability Operating Limit (IROL), where the IROL was determined in the planning horizon pursuant to FAC-010.	Attachment B sets the applicability of facilities operated below 200 kV (similar to FAC-003). These items reference PRC-023-4, Requirement R6, to which Attachment B is applicable. The language in part B2 of Attachment B of PRC-023-4 specifically addresses IROLs determined in the planning horizon pursuant to FAC-010-3; however, IROLs are established by the RC, and the Facilities critical to the derivation of the IROL are communicated to the GOs and TOs through FAC-014-3, Requirement R6 which states, "Each Reliability Coordinator that is impacted by an IROL shall provide Transmission Owners and Generation Owners within its Reliability Coordinator Area a list of Facilities owned by that entity that are critical to the derivation of the IROL." Accordingly, the GO and the TO are able to use the IROL information provided by the Reliability Coordinator. While part B2 of Attachment B for PRC-023-4 would benefit from a revision in response to the retirement of FAC-010, no reliability gap is created if FAC-010-3 is retired prior to the revision of these subparts given the above requirements for the RC. **Recommendations:** Revise Attachment B of PRC-023-4 in response to the retirement of FAC-010-3 to eliminate the references to FAC-10, PC's determining IROLs and IROLs in the Planning Horizon for identification of circuits as a monitored Facility of an Interconnection Reliability Operating Limit (IROL).

		A future team should consider the appropriateness for the circuits identified as applicable to Attachment B of PRC-023-4 to include due consideration for those planning events that result in System instability, Cascading, or uncontrolled separation as identified in the PC and TP's Planning Assessment for the Near-Term Transmission Planning Horizon.
PRC-026-1	R1. Each Planning Coordinator shall, at least once each calendar year, provide notification of each generator, transformer, and transmission line BES Element in its area that meets one or more of the following criteria, if any, to the respective Generator Owner and Transmission Owner: Criteria: 1. Generator(s) where an angular stability constraint exists that is addressed by a System Operating Limit (SOL) or a Remedial Action Scheme (RAS) and those Elements terminating at the Transmission station associated with the generator(s). 2. An Element that is monitored as part of an SOL identified by the Planning Coordinator's methodology[1] based on an angular stability constraint. *{[1] NERC Reliability Standard FAC-014-2 – Establish and Communicate System Operating Limits, Requirement R3.}*	Direct reference is made to the PC's SOL Methodology. Footnote 1 on page 3 of 84 references FAC-014-2, R3. Similar to the reference identified in Requirement R5, Part 5.1.2 of PRC-002-2, Requirement R1 of PRC-026-1 references the identification of facilities that are sensitive to angular stability constraints. Stability-related SOLs are communicated to the Planning Coordinator through FAC-014-3, Requirement R5, Parts 5.1 and, 5.2: R5. Each Reliability Coordinator shall provide: 5.1. Each Planning Coordinator within its RC Area, SOLs for its RC Area (including the subset of SOLs that are IROLs) at least once every twelve calendar months. 5.2. Each impacted Planning Coordinator the following information for each established stability limit and each established IROL at least once every twelve calendar months: 5.2.1. The value of the stability limit or IROL; 5.2.2. Identification of the Facilities that are critical to the derivation of the stability limit or IROL; 5.2.3. The associated IROL Tv for any IROL;

		5.2.4. The associated Contingency(ies); and, 5.2.5. The type of limitation represented by the stability limit or IROL (e.g., voltage collapse, angular stability). With this information, the PC can communicate the necessary SOL information to the applicable GO and TO as required by PRC-026-1, Requirement R1. While Criteria 1 and 2 of PRC-026-1 would benefit from a revision in response to the retirement of FAC-010, no reliability gap is created if FAC-010-3 is retired prior to the revision of these criteria given the above requirement for the RC. **Recommendations:** Revise PRC-026-1, Requirement R1 in response to the retirement of FAC-010-3 to eliminate the term, "Planning Coordinator's Methodology" which references FAC-10 and remove the reference to SOLs identified by the PC. A future team should consider that the PRC-026 R1 criteria reference Elements associated with angular stability as identified in the PC or TP's Planning Assessment for the Near-Term Transmission Planning Horizon.
TOP standards		No Action Required
TPL standards		No Action Required
VAR standards		No Action Required

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Mapping Document for FAC-010-3

The Project 2015-09 standard drafting team (SDT) is proposing the retirement of the NERC FAC-010-3 Reliability Standard. The SDT further proposes a new paradigm regarding the coordination of the Planning Assessment (TPL-001-4) with the establishment of System Operating Limits (SOLs) used in operations. Along with the retirement of FAC-010-3, this new paradigm consists of a new FAC-015-1 Reliability Standard and revisions to the existing FAC-011-3 and FAC-014-2 Reliability Standards. The SDT proposal for a new FAC-015-1 Reliability Standard, along with the proposed revisions contained in FAC-011-4 and FAC-014-3, represent an improvement for planning and operations to better coordinate analysis input assumptions and System performance criteria to address the reliability issues that are ultimately faced in Real-time operations.

The proposed construct does not make use of an SOL Methodology applicable to the planning horizon as required by the currently-effective FAC-010-3 due to its overall redundancy with TPL-001-4. However, FAC-015-1, Requirements R1 – R3 ensure that Planning Assessments performed for the Near-Term Transmission Planning Horizon, are bounded by modeling data and performance criteria that are equally limiting or more limiting than those established in accordance with the Reliability Coordinator's (RC's) SOL Methodology. FAC-015-1, Requirements R1 – R3 respectively address Facility Ratings System steady state voltage limits, and stability performance criteria used in the development of Planning Assessments. These requirements focus on the three components of SOLs used in operations and facilitate continuity between operations and planning. Implementing the processes required in FAC-015-1 Requirements R1 – R3 provides the Planning Coordinator (PC) with Facility Ratings, System steady-state voltage limits, and stability performance criteria that are equally limiting or more limiting than the Facility Ratings, System Voltage Limits, and stability performance criteria established in accordance with the Reliability Coordinator's SOL Methodology.

FAC-015-1, Requirements R4 and R5 address the communication and use of Facility Ratings, System steady-state voltage limits, and stability performance criteria for use in Planning Assessments between PCs and Transmission Planners (TPs).

FAC-015-1, Requirement R6 requires the PC to communicate any instability, Cascading or uncontrolled separation, along with key supporting information, identified in the Planning Assessments to the RCs and to impacted Transmission Operators (TOPs). This information may be useful to RC and TOPs in the establishment of stability limits and IROLs that will ultimately be used in Real-time operations.

By implementing Requirements R1 – R6 of FAC-015, Facility Ratings, System steady-state voltage limits and stability criteria used in the development of the Planning Assessment are effectively bounded by the Facility Ratings, System Voltage Limits, and stability performance criteria define and established in accordance with the RC's SOL Methodology (FAC-011-4 & FAC-014-3). Furthermore, potentially critical stability information is communicated by planners to operators. The result is an improvement in reliability by ensuring continuity between planning and operations.

The remainder of this document provides a mapping of the existing requirements in FAC-010-3 to the proposed action by the SDT. For easier reference applicable information from Table 1 of TPL-001-4 is included below. References to notes a – j and Planning Events P0 – P7 will be included in the mapping table where appropriate.

TPL-001-4 Table 1 (steady state & stability performance criteria notes for 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 P0 No Contingency
(Initial Condition - Normal System)

Category P1 Single Contingency
(Initial Condition - Normal System)
Loss of one of the following:

1. Generator (3 Ø fault)
2. Transmission Circuit (3 Ø fault)
3. Transformer (3 Ø fault)
4. Shunt Device (3 Ø fault)
5. Single Pole of DC line (SLG fault)

Category P2 Single Contingency
(Initial Condition - Normal System)

1. Opening of a line section w/o a fault
2. Bus Section Fault (SLG fault)
3. Internal Breaker Fault (non-Bus-tie Breaker) (SLG fault)
4. Internal Breaker Fault (Bus-tie Breaker) (SLG fault)

Category P3 Multiple Contingency
(Initial Condition - Loss of generator unit followed by System adjustments)
Loss of one of the following:

1. Generator (3 Ø fault)
2. Transmission Circuit (3 Ø fault)
3. Transformer (3 Ø fault)
4. Shunt Device (3 Ø fault)
5. Single Pole of DC line (SLG fault)

Category P4 Multiple Contingency
(Initial Condition - Normal System)

1. Generator (SLG fault)
2. Transmission Circuit (SLG fault)
3. Transformer (SLG fault)
4. Shunt Device (SLG fault)
5. Bus Section (SLG fault)
6. Loss of multiple elements caused by a stuck breaker (Bus-tie Breaker) attempting to clear a Fault on the associated bus

Category P5 Multiple Contingency
(Initial Condition - Normal System)
Delayed Fault Clearing due to the failure of a non-redundant relay protecting the Faulted element to operate as designed, for one of the following:
Generator (SLG fault)

1. Transmission Circuit (SLG fault)
2. Transformer (SLG fault)
3. Shunt Device (SLG fault)
4. Bus Section (SLG fault)

Category P6 Multiple Contingency
(Initial Condition - Loss of one of the following followed by System adjustments.

1. Transmission Circuit
2. Transformer
3. Shunt Device
4. Single Pole of DC line)

Loss of one of the following:

1. Transmission Circuit (3 Ø fault)
2. Transformer (3 Ø fault)
3. Shunt Device (3 Ø fault)
4. Single Pole of DC line (SLG fault)

Category P7 Multiple Contingency
(Initial Condition - Normal System)
The loss of:

- Any two adjacent (vertically or horizontally) circuits on common structure (SLG fault)
- Loss of a bipolar DC line (SLG fault)

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		**Translation to New Standard or Other Action**	**Description and Change Justification**
R1.	The Planning Authority shall have a documented SOL Methodology for use in developing SOLs within its Planning Authority Area. This SOL Methodology shall:	**FAC-010-3, Requirement R1 is addressed by:** 1. TPL-001-4, Requirements R1, R5, and R6 2. MOD-032-1, Requirement R2 3. FAC-008-3 Requirements R2 and R3 **TPL-001-4, Requirement R1:** **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. **R1.1** System models shall represent: **R1.1.1.** Existing Facilities **R1.1.2.** Known outage(s) of generation or Transmission	SOLs developed by the PC and TP for use in the planning horizon are addressed in other standards as described below. SOLs used in the Operations Planning, Same-day Operations, and Real-time Operations time horizons are developed in accordance with the RC's methodology as specified in FAC-011-4. The determination of Facility Ratings, System steady-state voltage limits, and stability performance criteria for use in the Long-term Planning time horizon are addressed as follows. It is important to note the new FAC-015-1 Reliability Standard bounds the following items as stated in the introduction of this document. **Facility Ratings** PCs and TPs are required, by TPL-001-4 Requirement R1, to maintain System models and to use data consistent with that which has been provided in accordance with MOD-032-1 (which supersedes the MOD-010 and MOD-012 standards). Facility Ratings are included in this data. These Facility Ratings: • Are determined in accordance with a Generator Owner's (GOs) or TO's Facility Ratings Methodology as required by FAC-008-3 R2 & R3 and

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	Facility(ies) with a duration of at least six months. **R1.1.3.** New planned Facilities and changes to existing Facilities **R1.1.4.** Real and reactive Load forecasts **R1.1.5.** Known commitments for Firm Transmission Service and Interchange **R1.1.6.** Resources (supply or demand side) required for Load **TPL-001-4, Requirement R5:** **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. **TPL-001-4, Requirement R6:** **R6.** Each Transmission Planner and Planning Coordinator shall define and document,	• Are provided to the PC and TP by the Facility Owner as required by MOD-032-1 R2. **System Steady-State Voltage Limits** TPL-001-4 R5 requires the TP and PC to have criteria for acceptable System steady state voltage limits. These limits are used in the Planning Assessments. **Transient and Voltage Stability Performance Criteria** TPL-001-4 Requirement R6 requires the TP and PC to have documented criteria to identify system conditions such as Cascading, voltage instability, or uncontrolled islanding. This criteria is applied when performing Planning Assessments to identify instances of Cascading, voltage instability, or uncontrolled islanding.

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	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. **MOD-032-1, Requirement R2:** **R2.** Each Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. **FAC-008-3, Requirement R2:** **R2.** Each Generator Owner shall have a documented methodology for determining Facility Ratings (Facility Ratings methodology) of its solely and jointly owned equipment connected between the location specified in R1 and the point of	

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		**Translation to New Standard or Other Action**	**Description and Change Justification**
		interconnection with the Transmission Owner that contains all of the following… **FAC-008-3, Requirement R3:** **R3.** Each Transmission Owner shall have a documented methodology for determining Facility Ratings (Facility Ratings methodology) of its solely and jointly owned Facilities (except for those generating unit Facilities addressed in R1 and R2) that contains all of the following…	
R1.1.	Be applicable for developing SOLs used in the planning horizon.		The proposed construct as described in the document introduction does not make use of an SOL Methodology applicable to the planning horizon or the development of SOLs in accordance with the PC's SOL Methodology. The requirements from TPL-001-4, MOD-032-1, and FAC-008-3 discussed above are applicable to the Long-term Planning time horizon and supersede the need for developing planning horizon SOLs.
R1.2.	State that SOLs shall not exceed associated Facility Ratings.	**TPL-001-4 Table1:** **Note: 'f'**	The proposed construct as described in the document introduction does not make use of an SOL Methodology applicable to the planning horizon or the development of SOLs in accordance with the PC's SOL Methodology. TPL-001-4 is constructed such that a Corrective Action Plan is developed to address those conditions where Facility Ratings are forecasted

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		**Translation to New Standard or Other Action**	**Description and Change Justification**
			to be exceeded in response to a planning event. The implementation of the Corrective Action Plan ensures the System is planned so there are no exceedances of Facility Ratings.
R1.3.	Include a description of how to identify the subset of SOLs that qualify as IROLs.	**TPL-001-4, Requirement R6:** **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.	The proposed construct as described in the document introduction does not make use of an SOL Methodology applicable to the planning horizon or the development of IROLs in accordance with the PC's SOL Methodology. In the proposed construct, PC and TP identify instances of instability, Cascading, or uncontrolled separation per the criteria developed in TPL-001-4 and communicate those instances to the Reliability Coordinator via FAC-015-1, Requirement R6. IROLs are established by the RC as required by FAC-014-3. TPL-001-4, Requirement R6 requires PC and TPs to document criteria or a methodology for use in identifying Cascading, voltage instability, or uncontrolled islanding in the analysis conducted for the annual Planning Assessment. This criterion addresses the conditions described in the definition for Interconnection Reliability Operating Limit (IROL).
R2.	The Planning Authority's SOL Methodology shall include a requirement that SOLs provide BES	**TPL-001-4 Table 1**	The proposed construct as described in the document introduction does not make use of an SOL Methodology applicable to the planning

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		**Translation to New Standard or Other Action**	**Description and Change Justification**
	performance consistent with the following:		horizon. The SDT proposes retiring Requirement R2 and its subparts due to redundancy with TPL-001-4 performance requirements contained in Table 1 notes a – j. The TPL-001-4 criteria provide the performance criteria for studies within the planning horizon that serve as the basis of the annual Planning Assessment the standard requires the PC and TP produce.
R2.1.	In the pre-contingency state and with all Facilities in service, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect expected system conditions and shall reflect changes to system topology such as Facility outages.	**TPL-001-4 Table1:** **Notes: 'a', 'f', 'g'** **TPL-001-4, Requirement R1:** **R1.** (refer to Requirement R1 section above)	Pre-contingency (Category P0) Bulk Electric System (BES) planned performance is addressed by TPL-001-4 Table 1 with notes a, f, and g specifying the applicable performance criteria. BES planned performance is based on expected system conditions and changes to system topology such as Facility outages as specified in TPL-001-4 Requirement R1.
R2.2.	Following the single Contingencies[1] identified in	**TPL-001-4 Table1:** **Notes: 'a', 'f', 'g'**	Single contingency (Categories P1 & P2) BES planned performance is addressed by TPL-001-4

[1] The Contingencies identified in R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		**Translation to New Standard or Other Action**	**Description and Change Justification**
	Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.		Table 1 with notes a through j specifying the applicable performance criteria.
R2.2.1.	Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.	**TPL-001-4 Table1:** **Note: 'd'** **TPL-001-4 Table 1:** Categories P1 & P2 Single Contingency Events **TPL-001-4 Table 1:** **Footnote 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.	

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		**Translation to New Standard or Other Action**	**Description and Change Justification**
R2.2.2.	Loss of any generator, line, transformer, or shunt device without a Fault.	**TPL-001-4 Table1:** Categories P1 & P2 Single Contingency Events	
R2.2.3.	Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.	**TPL-001-4 Table1:** Categories P1 & P2 Single Contingency Events	
R2.3.	Starting with all Facilities in service, the system's response to a single Contingency, may include any of the following:	**TPL-001-4 Table 1**	Allowable actions for BES planned performance in response to single contingencies are addressed in approved TPL-001-4 Table 1, including Consequential Load Loss and System Reconfiguration.
R2.3.1.	Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.	**TPL-001-4 Table1: Note: 'b'**	
R2.3.2.	System reconfiguration through manual or automatic control or protection actions.	**TPL-001-4 Table1: Note: 'e'**	
R2.4.	To prepare for the next Contingency, system adjustments may be made,	**TPL-001-4 Table1: Note: 'e'**	Allowable System adjustments for BES planned performance to prepare for the next

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		**Translation to New Standard or Other Action**	**Description and Change Justification**
	including changes to generation, uses of the transmission system, and the transmission system topology.	**TPL-001-4 Table 1:** Footnote 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.	Contingency are addressed TPL-001-4 Table 1 note e and footnote 9.
R2.5.	Starting with all Facilities in service and following any of the multiple Contingencies identified in Reliability Standard TPL-003 the system shall demonstrate transient, dynamic and voltage stability;	**TPL-001-4 Table1:** **Notes: 'a', 'f', 'g' 'j'** **TPL-001-4 Table1:** Categories P3 – P7 Multiple Contingency Events	Multiple contingency BES planned performance is addressed as Category P3 - P7 in TPL-001-4 Table 1. These include the multiple contingency events that start with all Facilities in service (P4, P5 & P7). Notes a through j from Table 1 (above) specify the applicable performance criteria.

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		**Translation to New Standard or Other Action**	**Description and Change Justification**
	all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.		
R2.6.	In determining the system's response to any of the multiple Contingencies, identified in Reliability Standard TPL-003, in addition to the actions identified in R2.3.1 and R2.3.2, the following shall be acceptable:	**TPL-001-4, Requirement R2.7.3** **TPL-001-4 Table 1**	Allowable actions for BES planned performance in response to multiple contingencies are addressed in TPL-001-4 Requirement R2.7.3 and Table 1, including all actions that were acceptable in response to single Contingencies discussed above; and load shedding and curtailment of Firm Transmission Service.
R2.6.1.	Planned or controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers.	**TPL-001-4, Requirement R2, Part 2.7.3.** **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	Table 1 in TPL-001-4 specifies the conditions where service interruption is acceptable.

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	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. **TPL-001-4 Table 1:** Footnote 9 (refer to R2.4 section) Footnote 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	

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		**Translation to New Standard or Other Action**	**Description and Change Justification**
		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.	
R3.	The Planning Authority's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:		The proposed construct as described in the document introduction does not make use of an SOL Methodology applicable to the planning horizon. The SDT also acknowledges that the June 2013 report from the Independent Experts Review Project identified FAC-010-2.1, Requirements R3 and R4 as "Requirements Recommended for Retirement" in Appendix E of the report (R5 had since been retired). Requirement R3 was identified as "More appropriate as a Guideline. This is a checklist."
R3.1.	Study model (must include at least the entire Planning Authority Area as well as the critical modeling details from other Planning Authority Areas that would impact the Facility or Facilities under study).	**TPL-001-4, Requirement R1:** **R1**. (refer to Requirement R2.1 section above)	Study model used for BES planned performance is specified in approved TPL-001-4, Requirement R1.

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		**Translation to New Standard or Other Action**	**Description and Change Justification**
R3.2.	Selection of applicable Contingencies.	**TPL-001-4 Table1:** Categories P1 – P7 Planning Events	Applicable contingencies for BES planned performance are specified in approved TPL-001-4 Table 1.
R3.3.	Level of detail of system models used to determine SOLs.	**TPL-001-4, Requirement R1:** **R1.** (refer to Requirement R1 section above)	Model details for BES planned performance are specified in approved TPL-001-4, Requirement R1.
R3.4.	Allowed uses of Remedial Action Schemes.	**TPL-001-4, Requirement R2, Part 2.7:** **2.7.** For planning events shown in TPL-001-4 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 TPL-001-4, 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	TPL-001-4, Requirement R2.7 requires the development of a Corrective Action Plan to address system deficiencies. The Corrective Action Plan is required to include any automatic tripping or other automated protection that is required to meet the performance criteria in TPL-001-4 Table 1.

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		**Translation to New Standard or Other Action**	**Description and Change Justification**
		achieve required System performance. Examples of such actions include: • 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.	
R3.5.	Anticipated transmission system configuration, generation dispatch and Load level.	**TPL-001-4, Requirement R1:** **R1.** (refer to Requirement R1 section above)	Anticipated transmission dispatch, generation, and load levels are incorporated into study models used for BES planned performance as specified in TPL-001-4, Requirement R1.

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		**Translation to New Standard or Other Action**	**Description and Change Justification**
R3.6.	Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_V	See mapping for Requirement R1, Part 1.3	See mapping for Requirement R1.3
R4.	The Planning Authority shall issue its SOL Methodology, and any change to that methodology, to all of the following prior to the effectiveness of the change:		The proposed construct as described in the document introduction does not make use of an SOL Methodology applicable to the planning horizon. The modeling and performance requirements as well as the reliability objectives of FAC-010-3 are redundant with those in TPL-001-4. Furthermore, the Planning Assessment required by TPL-001-4 is distributed, in accordance with TPL-001-4 Requirement R8 and IRO-017 Requirement R3, to all applicable entities listed in FAC-010-3 Requirement R4. The SDT also acknowledges that the June 2013 report from the Independent Experts Review Project identified FAC-010-2.1, Requirements R3 and R4 as "Requirements Recommended for Retirement" in Appendix E of the report (Requirement R5 had since been retired). Requirement R4 was identified as "More appropriate as a Guideline. Description of
R4.1.	Each adjacent Planning Authority and each Planning Authority that indicated it has a reliability-related need for the methodology.	**TPL-001-4, Requirement R8:** **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.	
R4.2.	Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority's Planning Authority Area.	**TPL-001-4, Requirement R8:** **R8.** (refer to Requirement R4, Part 4.1 section above) **IRO-017-1, Requirement R3:**	

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		**Translation to New Standard or Other Action**	**Description and Change Justification**
		R3. Each Planning Coordinator and Transmission Planner shall provide its Planning Assessment to impacted Reliability Coordinators**.**	appropriate coordination does not rise to a Standard.”
R4.3.	Each Transmission Planner that works in the Planning Authority’s Planning Authority Area.	See mapping for Requirement R4, Part 4.1	

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the Board of Trustees.

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
Draft Reliability Standard posted for Informal Comment Period	07/14/16 – 08/12/16

Anticipated Actions	Date
45-day formal comment period with initial ballot	September 2017 – November 2017
45-day formal comment period with additional ballot	January 2018 – February 2018
10-day final ballot	February 2018
NERC Board adoption	May 2018

A. Introduction

1. **Title:** System Operating Limits Methodology for the Operations Horizon

2. **Number:** FAC-011-~~3~~4

3. **Purpose:** ~~-~~To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Reliability Coordinator

5. **Effective Date:** ~~——~~ See Implementation Plan for ~~the Revised Definition of "Remedial Action Scheme".~~Project 2015-09.

B. Requirements and Measures

R1. ~~The~~Each Reliability Coordinator shall have a ~~documented~~ methodology for ~~use in developing~~establishing SOLs (i.e., SOL Methodology) within its Reliability Coordinator Area. ~~This~~*[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology.

~~R1.~~R2. Each Reliability Coordinator shall~~:~~ include in its SOL Methodology the method for Transmission Operators to determine the applicable owner-provided 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. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

~~**1.1.** Be applicable for developing SOLs used in the operations horizon.~~

~~**1.2.** State that SOLs shall not exceed associated Facility Ratings.~~

M2. ~~Include a description of how to identify the subset of SOLs that qualify~~Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R2.

R3. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the System Voltage Limits to be used in operations. The method shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

~~1.3.~~ Require that BES buses/stations have an associated System Voltage Limit except for the BES buses/stations that may be excluded as ~~IROLs.~~

3.1. ~~The~~ specified in the Reliability Coordinator's SOL Methodology ~~shall include a requirement that SOLs provide BES~~ ;

3.2. Require that System Voltage Limits respect the Facility voltage Ratings;

3.3. Require that System Voltage Limits are higher than in-service under voltage load shedding (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;

3.6. Address coordination of System Voltage Limits between adjacent Transmission Operators in its Reliability Coordinator Area; and

3.7. Address coordination of System Voltage Limits between adjacent Reliability Coordinator Areas within an Interconnection.

M3. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R3.

R4. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the stability limits to be used in operations. The method shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

~~1.4.~~4.1. Specify stability performance ~~consistent with~~ criteria, including any margins applied. The criteria shall include the following:

4.1.1. ~~In the pre-contingency~~ steady-state~~, the BES shall demonstrate~~ voltage stability;

4.1.2. transient~~, dynamic and~~ voltage response;

4.1.3. angular stability; ~~all Facilities shall be within their Facility Ratings and within their thermal, voltage and~~ and

4.1.4. System damping.

4.2. Require that stability limits~~. In~~ are established to meet the ~~determination of SOLs,~~criteria specified in Part 4.1 for the ~~BES condition used shall reflect current or expected system~~Contingencies identified in Requirement R5.

4.3. Describe how the Reliability Coordinator establishes stability limits when there is an impact to more than one Transmission Operator in its Reliability Coordinator Area.

~~1.5.~~4.4. Describe how instability risks are identified, considering levels of transfers, Load and generation dispatch, and System conditions ~~and shall reflect~~ including any changes to ~~system~~System topology such as Facility outages~~.~~ ;

~~**1.6.** Following the single Contingencies[1] identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.~~

4.5. ~~Single line to~~ Describe the level of detail that is required for the study model(s); including the extent of the Reliability Coordinator Area, as well as the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.

4.6. Describe the allowed uses of Remedial Action Schemes and other automatic post-Contingency mitigation actions; the planned use of underfrequency load shedding (UFLS) is not allowed in the establishment of stability limits.

M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R4.

R5. Each Reliability Coordinator shall include in its SOL Methodology the method for identifying the single Contingencies and multiple Contingencies for use in determining stability limits and performing Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs). The method shall include: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1. The following list of single Contingency events for use in determining stability limits and performing OPAs and RTAs:

5.1.1. Loss of any of the following either by single phase to ground or ~~3-~~three phase Fault (whichever is more severe~~),~~) with ~~Normal Clearing, on any Faulted~~ normal clearing, or without a Fault:

- generator~~, line, ~~;
- transmission circuit;
- transformer~~, or ~~;
- shunt device~~.~~; or

~~**1.6.1.** Loss of any generator, line, transformer, or shunt device without a Fault.~~

- ~~Single~~single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

~~**1.7.** In determining the system's response to a~~ Any additional types of single Contingency~~, the following shall be acceptable:~~

~~[1] The Contingencies identified in FAC-011-R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.~~

~~**1.7.1.** Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.~~

~~**1.7.2.** Interruption of other network customers, (a) only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or (b) if the real-time operating conditions are more adverse than anticipated in the corresponding studies~~

~~**1.7.3.** System reconfiguration through manual or automatic control or protection actions.~~

~~**1.8.** To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.~~

~~**R2.** The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:~~

~~**2.1.** Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)~~

~~**2.2.** Selection of applicable Contingencies~~

5.2. ~~A process for determining which of the~~ events identified for use in determining stability limits~~ associated with the list~~, or for use in performing OPAs and RTAs.

5.3. Any types of multiple ~~contingencies (~~Contingency events identified for use in determining stability limits, or for use in performing OPAs and RTAs.

~~**2.3.**~~**5.4.** The method for considering the Contingency events provided by the Planning ~~Authority~~Coordinator in accordance with FAC-~~014~~015-1, Requirement ~~6) are applicable for use in the operating horizon given the actual or expected system conditions.~~ R6 to identify the Contingencies for use in determining stability limits.

~~**2.3.1.** This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies.~~

~~**2.4.** Level of detail of system models used to determine SOLs.~~

~~**2.5.** Allowed uses of Remedial Action Schemes.~~

~~**2.6.** Anticipated transmission system configuration, generation dispatch and Load level~~

M5. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R5.

R6. Each Reliability Coordinator shall include in its SOL Methodology: *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

6.1. A description of how to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs).

~~**2.7.**~~**6.2.** Criteria for determining when violating a SOL qualifies as an ~~Interconnection Reliability Operating Limit (~~IROL~~)~~ and criteria for developing any associated IROL T_V.

M6. ~~The~~ Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R6.

R7. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to communicate SOLs it established to its Reliability Coordinator(s). The method shall address the periodicity of SOL communication. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M7. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R7.

~~**R3.**~~**R8.** Each Reliability Coordinator shall ~~issue~~provide its SOL Methodology and any changes to ~~that methodology,~~the SOL Methodology prior to the effective date of the SOL Methodology, to ~~the effectiveness of the Methodology or of a change to the Methodology, to all of the following: :~~ *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

~~**3.1.**~~**8.1.** Each adjacent Reliability Coordinator within an Interconnection, and each Reliability Coordinator that ~~indicated~~requests and indicates it has a reliability-related need ~~for the methodology.~~;

8.2. Each Planning ~~Authority~~Coordinator and Transmission Planner that ~~models~~is responsible for planning any portion of the Reliability ~~Coordinator's~~Coordinator Area;

~~**3.2.**~~**8.3.** Each Transmission Operator within its Reliability Coordinator Area.

~~**3.3.** Each Transmission Operator~~ Acceptable evidence that ~~operates in~~ the Reliability Coordinator ~~Area.~~

~~C. Measures~~

~~**M1.** The Reliability Coordinator's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.~~

~~**M2.**~~**M8.** ~~The Reliability Coordinator shall have evidence it issued~~provided its SOL Methodology~~, and any changes to that methodology, including the date they were issued, in accordance~~ to the entities identified in Requirement R8 may include, but is

not limited to, dated electronic or hard copy documentation such as emails with Requirement 4. receipts, registered mail receipts, or postings to a secure web site with accompanying notification(s).

D.C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring ResponsibilityEnforcement Authority:
Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Reliability Coordinator shall self-certify its compliance to the Compliance Monitor at least once every three years. New Reliability Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

Data"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.

1.3.1.2. Evidence Retention:
The Reliability Coordinator shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Reliability Coordinator shall make the following available for inspection during an on-site auditThe 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 theits Compliance Monitor or within 15

business daysEnforcement Authority to retain specific evidence for a longer period of a requesttime as part of an investigation upon complaint:.

1.4.1 SOL Methodology.

1.4.2 Superseded portionsThe Reliability Coordinator shall keep data or evidence of its SOL Methodology that had been made within the past 12 months.

1.4.3 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

2. Levels of Non-Compliance for Western Interconnection: (To be replaced with VSLs once developed and approved by WECC)

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions exists:

2.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.

- **Level 2:** The SOL Methodology did not include a requirement to address all of the elements in R3.1, R3.2, R3.4with Requirements R1 through R3.7 and E1R8 for the current year plus the previous 12 calendar months. .

2.2. Level 3: There shall be a level three non-compliance if any of the following conditions exists:

2.2.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.

2.2.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.

2.2.3 The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.1, R3.2, R3.4 through R3.7.

2.3. Level 4: The SOL Methodology was not issued to all required entities in accordance with R4.

1.3. Compliance Monitoring and Enforcement Program

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

Violation Severity Levels~~:~~

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The Reliability Coordinator did not have a SOL Methodology for establishing SOLs within its Reliability Coordinator Area.
~~R1~~**R2.**	~~Not applicable.~~ N/A	~~The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.2~~N/A	The Reliability Coordinator ~~has a documented~~ included in its SOL Methodology the method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations, but the method did not address the use ~~in developing SOLs within~~of common Facility Ratings between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area~~, but it does not address R1.3.~~	The Reliability Coordinator ~~has a documented~~ did not include in its SOL Methodology the method for ~~use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.1~~Transmission Operators to determine the applicable owner-provided Facility Ratings to be used~~.~~ ~~OR~~ ~~The Reliability Coordinator has no documented SOL Methodology for use~~ in ~~developing SOLs within its Reliability Coordinator Area.~~operations.

~~R2~~**R3.**	The Reliability Coordinator~~'s~~ failed to incorporate one of the Parts of Requirement R3 into its SOL Methodology ~~requires that SOLs are set to meet BES performance following single contingencies, but does not require that SOLs are set to meet BES performance in the pre-contingency state. (R2.1)~~ .	~~Not applicable.~~The Reliability Coordinator failed to incorporate two of the Parts of Requirement R3 into its SOL Methodology.	The Reliability Coordinator~~'s~~ failed to incorporate three of the Parts of Requirement R3 into its SOL Methodology ~~requires that SOLs are set to meet BES performance in the pre-contingency state, but does not require that SOLs are set to meet BES performance following single contingencies. (R2.2 – R2.4)~~.	~~The Reliability Coordinator's SOL Methodology does not require that SOLs are set to meet BES performance in the pre-contingency state and does not require that SOLs are set to meet BES performance following single contingencies. (R2.1 through R2.4)~~The Reliability Coordinator failed to incorporate four or more of the Parts of Requirement R3 into its SOL Methodology.
~~R3~~ **R4.**	The Reliability ~~Coordinator's~~Coordinator failed to incorporate one of the Parts of Requirement R4 into its SOL Methodology ~~includes a description for all but one of the following: R3.1 through R3.7~~.	The Reliability ~~Coordinator's~~Coordinator failed to incorporate two of the Parts of Requirement R4 into its SOL Methodology ~~includes a description for all but two of the following: R3.1 through R3.7~~.	The Reliability ~~Coordinator's~~Coordinator failed to incorporate three of the Parts of Requirement R4 into its SOL Methodology ~~includes a description for all but three of the following: R3.1 through R3.7~~.	The Reliability ~~Coordinator's SOL Methodology is missing a description of~~Coordinator failed to incorporate four or more of the ~~following: R3.1 through R3.7~~Parts of Requirement R4 into its SOL Methodology.
R5.	N/A	The Reliability Coordinator failed to incorporate one of the Parts 5.2, 5.3 or 5.4 of Requirement R5 into its SOL Methodology.	The Reliability Coordinator failed to incorporate two of the Parts 5.2, 5.3, or 5.4 of Requirement R5 into its SOL Methodology.	The Reliability Coordinator failed to incorporate Part 5.1 of Requirement R5 into its SOL Methodology. OR The Reliability Coordinator failed to incorporate Parts 5.2, 5.3, and 5.4 of

				Requirement R5 into its SOL Methodology.
~~R3.6~~**R6.**	N/A	N/A	~~N/A~~The Reliability Coordinator failed to include Part 6.1 (a description of how to identify the subset of SOLs that qualify as IROLs) in its SOL Methodology. OR The Reliability Coordinator failed to include Part 6.2 (a criteria for determining when violating a SOL qualifies as an IROL in its SOL Methodology. OR The Reliability Coordinator failed to include Part 6.2 (criteria for developing any associated IROL T_V) in its SOL Methodology.	~~N/A~~The Reliability Coordinator failed to include Parts 6.1 and 6.2 in its SOL Methodology.
R7.	N/A	N/A	The Reliability Coordinator did not include in its SOL Methodology the periodicity of SOL communications for Transmission Operators to communicate SOLs the	The Reliability Coordinator did not include in its SOL Methodology the method for Transmission Operators to communicate SOLs it established or the

			Transmission Operator established.	periodicity of SOL communication.
~~R4~~**R8.**	The Reliability Coordinator ~~failed to issue~~provided its new or revised SOL Methodology ~~and/or one or more changes to that methodology to one of the required entities specified~~to a requesting Reliability Coordinator in ~~R4.1, R4.2, and R4.3.~~ ~~OR~~ ~~For a change in methodology, the changed methodology was provided to one or more of the required entities before the effectiveness of the change,~~accordance with Part 8.4 but was ~~provided to all the required entities no more~~late by less than or equal to 10 calendar days ~~after the effectiveness of the change~~.	The Reliability Coordinator ~~failed to issue~~ provided its new or revised SOL Methodology ~~and/or one or more changes to that methodology to two of the required entities specified~~to a requesting Reliability Coordinator in ~~R4.1, R4.2, and R4.3.~~ ~~OR~~ ~~For a change in methodology, the changed methodology~~ accordance with Part 8.4, but was ~~provided to one or more of the required entities~~late by more than 10 calendar days ~~after the effectiveness of the change, but~~ but less than or equal to 20 calendar days ~~after the effectiveness of the change~~.	The Reliability Coordinator failed to ~~issue~~provide its new or revised SOL Methodology ~~and/or~~to one ~~or more changes to that methodology to three~~ of the ~~required entities~~parties specified in ~~R4~~Parts 8.1~~, R4.2, and R4~~ through 8.3. OR ~~For a change in methodology, the changed methodology was~~ The Reliability Coordinator provided ~~to one or more of required entities~~its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Part 8.4, but was late by more than 20 calendar days ~~after the effectiveness of the change, but~~ but less than or equal ~~to30~~to 30 calendar days ~~after the effectiveness of the change~~.	The Reliability Coordinator failed to ~~issue~~provide its new or revised SOL Methodology ~~and/or one or more changes~~ to ~~that methodology to four~~two or more of the ~~required entities~~parties specified in ~~R4~~Parts 8.1~~, R4.2, and R4~~ through 8.3. OR ~~For a change in methodology, the changed methodology was provided~~ The Reliability Coordinator failed to provide its new or revised SOL Methodology to one or more of the ~~required entities more than30~~parties specified in Parts 8.1 through 8.3 prior to the effective date of the SOL Methodology. OR The Reliability Coordinator provided its new or revised SOL Methodology to a

				requesting Reliability Coordinator in accordance with Part 8.4, but was late by more than 30 calendar days~~ after the effectiveness of the change~~. OR The Reliability Coordinator failed to provide its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Part 8.4.

~~E.~~D. Regional ~~Differences~~Variances

~~3.~~ The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:

~~3.1.~~ As governed by the requirements of R3.3, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:

~~3.1.1~~ Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.

~~3.1.2~~ A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7

~~3.1.3~~ Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.

~~3.1.4~~ The failure of a circuit breaker associated with a Remedial Action Scheme to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.

~~3.1.5~~ A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.

~~3.1.6~~ A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-011.

~~3.1.7~~ The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.

~~3.2.~~ SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:

~~3.2.1~~ All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.

~~3.2.2~~ Cascading does not occur.

~~3.2.3~~ Uncontrolled separation of the system does not occur.

~~**3.2.4** The system demonstrates transient, dynamic and voltage stability.~~

~~**3.2.5** Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.~~

~~**3.2.6** Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.~~

~~**3.2.7** To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.~~

~~**3.3.** SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:~~

~~**3.3.1** Cascading does not occur.~~

~~**3.4.** The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.~~

None.

E. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
2		Changed the effective date to October 1, 2008 Changed "Cascading Outage" to "Cascading" Replaced Levels of Non-compliance with Violation Severity Levels Corrected footnote 1 to reference FAC-011 rather than FAC-010	Revised
2	June 24, 2008	Adopted by Board of Trustees: FERC Order 705	Revised
2	January 22, 2010	Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order	Update
2	February 7, 2013	R5 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	
2	November 21, 2013	R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	
2	February 24, 2014	Updated VSLs based on June 24, 2013 approval.	
3	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
~~3~~4	~~November 19, 2015~~	~~FERC Order issued approving FAC-011-3. Docket No. RM15-13-000.~~Project 2015-09 – Adopt revisions to standard.	Revisions

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Rationale for FAC-011-4

September 2017

Requirement R1

Each Reliability Coordinator shall have a methodology for establishing SOL (i.e., SOL Methodology) within its Reliability Coordinator Area.

Rationale R1

The three subparts in Requirement R1 in currently-effective Reliability Standard FAC-011-3 are either not necessary for reliability, or they are addressed through other mechanisms in FAC-011-4 and therefore are not included as part of Requirement R1.

Requirement R1.1 in currently-effective FAC-011-3 requires that the SOL Methodology shall be applicable for developing SOLs used in the operations horizon. The revised Requirement R1 is applicable to the Operations Planning Time Horizon. Accordingly, there is no reliability-related need to have a requirement specifying that the Reliability Coordinator's (RC's) SOL Methodology is applicable for developing SOLs used in the operations horizon. Additionally, the purpose of the standard references SOLs used in the reliable operation of the BES.

Requirement R1.2 in currently-effective FAC-011-3 requires that the SOL Methodology state that SOLs shall not exceed associated Facility Ratings. Facility Ratings to be used in operations as System Operating Limits (SOLs) are addressed through FAC-011-4 Requirement R2 and therefore is not addressed as a subpart of R1.

Requirement R1.3 in currently-effective FAC-011-3 requires that the SOL Methodology include a description of how to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs). This language is preserved in Requirement R6.

Requirement R2

Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the applicable owner-provided 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.

Rationale R2

The reliability objectives of Requirement R2 are 1) to ensure that the owner-provided Facility Ratings that are selected for use in operations are determined in accordance with the RC's SOL Methodology, and 2) to ensure the consistent use of applicable Facility Ratings between RCs and their Transmission Operators (TOP). For example, if a Transmission Owner (TO) provides three levels of Facility Ratings pursuant to Reliability Standard FAC-008-3, and another TO provides five

levels of ratings, the RC will establish the method for the TOPs to determine which of those Facility Ratings will be utilized in common with the TOP and the RC for monitoring and assessments.

The intent of Requirement R2 is not to change, limit, or modify Facility Ratings determined by the equipment owner. The equipment owner is still responsible for determining the Facility Ratings per FAC-008. The intent is to use those owner-provided Facility Ratings in a consistent manner between the TOP and RC during operations.

Requirement R3

Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the System Voltage Limits to be used in operations. The method shall:

- **3.1** Require that BES buses/stations have an associated System Voltage Limit except for the BES buses/stations that may be excluded as specified in the Reliability Coordinator's SOL Methodology;
- **3.2** Require that System Voltage Limits respect the Facility voltage Ratings;
- **3.3** Require that System Voltage Limits are higher than in-service undervoltage load shedding (UVLS) relay settings;
- **3.4** Identify the lowest allowable System Voltage Limit;
- **3.5** Require the use of common System Voltage Limits between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area;
- **3.6** Require coordination of System Voltage Limits between adjacent Transmission Operators in its Reliability Coordinator Area;
- **3.7** Require coordination of System Voltage Limits between adjacent Reliability Coordinator Areas within an Interconnection.

Rationale R3

System Voltage Limits (SVLs) are intended to provide reliable pre- and post-contingency System performance for operations within a Reliability Coordinator Area and across neighboring Reliability Coordinator Areas. The proposed definition of System Voltage Limits includes normal and emergency voltage limits, and can also include time-based voltage limits, depending on what the RC requires. It is expected that the RC would require a set of System Voltage Limits to cover the entire BES system within its Reliability Coordinator Area for facility-based voltage limits, voltage instability, voltage collapse and misactuation of relay elements.

Both high and low limits are required. High limits tend to be associated with equipment/facility limitations. Low limits are often used to prevent phenomena associated with low voltages such as system instability, voltage collapse, and potential misactuation of relay elements. Identifying the set of "System Voltage Limits", both high and low, assures that all voltage limits associated with a particular bus or station, or the equipment connected to it, have been considered and the most limiting are used.

While all BES buses/stations have equipment related voltage ratings, there may be reasons that certain buses/stations do not require a System Voltage limit. Part 3.1 allows RCs to identify certain buses/stations that may be excluded from having an associated System Voltage Limit. These exempt buses/stations should be identified in the RC's SOL Methodology with appropriate reasoning. The identification of such buses/stations could be documented by citing the type of buses/stations (based on voltage level or area of the System) as opposed to a more detailed list of individual buses/stations which are exempt.

Buses or stations may not require System Voltage Limits when the voltage at the station has no material impact on System performance and associated SOLs. For example, System Voltage Limits at neighboring/nearby stations may be sufficient to protect the facilities from high voltage, and the System from instability, voltage collapse, and misactuation of relay elements.

Parts 3.5-3.7 identifies the RC as the entity responsible for developing the overall method for TOPs and RCs to determine and coordinate System Voltage Limits in their areas and neighboring areas.

Part 3.2 provides that in establishing System Voltage Limits, the SOL Methodology shall respect any Facility voltage Ratings established by the Generation Owner or TO under FAC-008. Recognizing that voltage limits are difficult to reflect by facility, the System Voltage Limits provided for stations/buses should reflect any Facility voltage Ratings for facilities that terminate at or are adjacent to the stations/buses with System Voltage Limits.

FERC Order No. 818 issued November 19, 2015, states that UVLS should not be triggered for an N-1 Contingency. As such, under Part 3.3, the SOL Methodology shall ensure System Voltage Limits are set above all UVLS settings to avoid UVLS operation following N-1 Contingencies.

Requirement R4

Each Reliability Coordinator shall include in its SOL Methodology the method for determining the stability limits to be used in operations. The method shall:

4.1 Specify stability performance criteria, including any margins applied. The criteria shall include the following:

- **4.1.1** steady-state voltage stability;
- **4.1.2** transient voltage response;
- **4.1.3** angular stability;
- **4.1.4** System damping;

4.2 Require that stability limits are established to meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5;

4.3 Describe how the Reliability Coordinator establishes stability limits when there is an impact to more than one Transmission Operator in its Reliability Coordinator Area;

4.4 Describe how instability risks are identified, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages;

4.5 Describe the level of detail that is required for the study model(s), including the extent of the Reliability Coordinator Area, as well as the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.

4.6 Describe the allowed uses of Remedial Action Schemes (RAS) and other automatic post-Contingency mitigation actions[1].

Rationale R4

Reliability Standard FAC-011-3 currently requires the System to demonstrate transient, dynamic and voltage stability for both pre- and post-contingent states, but does not provide specifics. By requiring specific stability criteria within the SOL Methodology, the standard is improved and provides greater clarity and uniformity on practices across the industry. The set of commonly used stability criteria specified in Requirement R4 Part 4.1 is based upon information provided by standard drafting team members and observers, including many RCs and TOPs. Industry input from areas with significant experience managing stability issues led to the inclusion of system damping.

Also included in Part 4.1 is language requiring the SOL Methodology to include descriptions of how margins are applied. This language was added to explicitly capture the practices in use by RCs for off-line or on-line calculated stability limits, including any margin used in the application of the stability limits. It is left to the RC what type of margin to use (a percentage of the limit or a fixed MW value, for example), if it uses one at all.

Requirement R4 Part 4.2 provides the link to the Contingencies which must be respected in operations, which are unchanged from the current standard. In response to industry comments, Contingency specifications were moved to a separate requirement.

Requirement R4 Part 4.3 was introduced to preclude ambiguity in the resolution of stability limits when multiple TOPs within an RC's footprint are impacted. For example, this requirement may be met by providing language in the SOL Methodology describing which TOP (or identifying that the RC) has the responsibility to determine stability SOLs impacting multiple TOPs, and could also determine how to choose between stability limits derived by multiple TOPs for the same stability limit exceedance.

Requirement R4 Parts 4.4, 4.5 and 4.6 require that the SOL Methodology provide a description of the key parameters that must be considered and monitored when performing analyses to determine the stability limits. The intent of these parts is to help ensure that the SOL Methodology provides guidance such that the process/method used by the RC to determine stability limits may be repeated, successfully, by anyone reading the SOL Methodology. For example, the SOL Methodology could state that stability limits will be determined for any combination of all facilities in and single facility out

[1] The planned use of underfrequency load shedding (UFLS) is not allowed in the establishment of stability limits.

conditions, for all valid transfer conditions for the highest allowable thermal transfer condition (i.e. winter ratings), plus a flow margin of 10%, to account for potential emergency transfer conditions. This level of detail would allow TOPs and other entities to consistently duplicate results from study to study. Part 4.5 combines FAC-011-3 Requirements R3.1 and R3.4 into a single part while providing flexibility to the extent of the Reliability Coordinator Area (including other Reliability Coordinator Areas) that must be modeled to reflect the varying needs for different types of stability limits (e.g. local single unit stability up to wide area or inter area instability). By recognizing that some types of localized stability issues do not require entire Reliability Coordinator Area modeling to establish a stability limit, this revision aligns with and promotes the ability to monitor these localized areas with real time stability analysis tools.

Requirement 4 Part 4.4 is specifically intended to address the need for the SOL Methodology to identify the method for ensuring stability limits are "valid" (i.e. provide stable operations pre- and post-Contingency) for the Operational Planning Analysis (OPA) and Real-time Assessments (RTA) for which they will be used. Since stability limits may vary based on the system topology, load, generation dispatch, etc., and the current definitions for OPA and RTA include "An evaluation of … system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for ….operations", the stability limits used in OPA/RTA should be "valid" for those system conditions.

As described within PRC-006-2 in alignment with FERC Order No. 763, underfrequency load shedding (UFLS) are designed "to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures." In the establishment of stability limits under Requirement R4 Part 4.6, UFLS programs are expressly prohibited from being considered as an acceptable post-Contingency mitigation action in order to preserve the intended availability of UFLS as a "last resort system preservation measure".

Requirement R5

Each Reliability Coordinator shall include in its SOL Methodology the method for identifying the single Contingencies and multiple Contingencies for use in determining stability limits and performing Operational Planning Analyses (OPAs) and Real-time Assessments (RTAs). The method shall include:

5.1 The following list of single Contingency events for use in determining stability limits and performing OPAs and RTAs:

5.1.1 Loss of any of the following either by single phase to ground or three phase Fault (whichever is more severe) with normal clearing, or without a Fault:

- generator;
- transmission circuit;
- transformer;
- shunt device;
- single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

5.2 Any additional types of single Contingency events identified for use in determining stability limits, or for use in performing OPAs and RTAs.

5.3. Any types of multiple Contingency events identified for use in determining stability limits, or for use in performing OPAs and RTAs.

5.4 The method for considering the Contingency events provided by the Planning Coordinator in accordance with FAC-015-1 Requirement R6 to identify the Contingencies for use in determining stability limits.

Rationale R5

Requirement R5 combines both the requirements for single Contingencies (formerly in Requirement R2.2 of FAC-011-3) and for multiple Contingencies (formerly in Requirement R3.3 of FAC-011-3) for ease of interpretation.

Furthermore, Requirement R5 continues to maintain the flexibility that existed in Requirement R2.2 and Requirement R3.3 for each RC to determine which additional single and multiple Contingencies to respect given the uniqueness of their system. Through both the feedback received as a result of the July 2016 informal posting and the May 2016 technical conference it was evident that both the drafting team and industry agree that sufficient flexibility is required for each RC to determine its own methodology for addressing Contingencies other than single Contingencies.

Requirement R5 mandates that the RC specify which types of Contingencies (both single and multiple) are used for determining stability limits as well as those used in checking for all types of SOL exceedances in OPAs and RTAs (thermal, voltage and stability limits). The SOL Methodology is the best place to communicate which Contingencies the RC is respecting in their footprint such that all TOPs and any neighboring RCs understand one another's internal and interconnection-related reliability objectives.

Requirement R5 Part 5.1.1 identifies the types of single Contingency events that at a minimum must be used for stability limit analysis and for performing OPAs and RTAs. However, other types of single Contingency events such as inadvertent breaker operation and bus faults may be considered if the probability of such an event is relevant. The method for determining those Contingencies must also be identified in the RC's methodology as per Requirement R5 Part 5.2.

Requirement R5 Parts 5. 1 through 5.4 require that differences in Contingency events for determining stability limits, those used for OPAs and those used for RTAs, be specified in the RC's methodology. It is important to distinguish between Contingencies used for determining stability limits and those that are actually applied in OPAs and RTAs as only specific system conditions may actually warrant their use in the days leading up to real-time operations. For example, multiple Contingencies at heightened risk under specific weather or system conditions may not need to be respected (and thus monitored) the majority of the time when these conditions are not present.

Requirement R5 Part 5.4 compliments the proposed Requirement R6 in FAC-015-1 by ensuring the RC's methodology describes how the Contingency event information from the Planning Coordinator is used in deriving stability limits used in operations.

Requirement R6

Each Reliability Coordinator shall include in its SOL Methodology:

6.1 A description of how to identify the subset of SOLs that qualify as IROLs.
6.2 Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_V.

Rationale R6

The two IROL related requirements in FAC-011-3 were preserved under Requirement R6.

Requirement R7

Each Reliability Coordinator shall include in its SOL Methodology the method and periodicity for Transmission Operators to communicate SOLs it established to its RC(s).

Rationale R7

Requirement R7 serves as a companion to FAC-014-3 Requirement R3 which states, *"The Transmission Operator shall provide its SOLs to its Reliability Coordinator in accordance with its Reliability Coordinator's SOL Methodology."*

The language in Requirement R7 is written to provide clarity that the TOP is responsible for communicating only those SOLs that it established for its own Transmission Operator Area. The TOP is not responsible for communicating SOLs established by other TOPs that it uses in its analyses.

While it is possible to address communication of SOLs through TOP-003-3 and IRO-010-2, the standard drafting team determined that the communication of SOLs was of such importance to the reliability of the BES that it should be addressed specifically in the RC's SOL Methodology and in FAC-014-3. Additionally, the aforementioned Reliability Standards address the data specifically necessary for performing OPA, Real-time monitoring, and RTA. SOL information may be necessary for other uses beyond these analyses, for example in outage coordination assessments.

Requirement R8

Each Reliability Coordinator shall provide its new or revised SOL Methodology to:

8.1 Each adjacent Reliability Coordinator within its Interconnection prior to the effective date of the SOL Methodology;
8.2 Each Planning Coordinator and Transmission Planner responsible for planning any portion of the Reliability Coordinator Area prior to the effective date of the SOL Methodology;
8.3 Each Transmission Operator within its Reliability Coordinator Area prior to the effective date of the SOL Methodology;

8.4 Each requesting Reliability Coordinator that indicates a reliability-related need and is not considered adjacent in Part 8.1, within 30 calendar days of receiving the request.

Rationale R8

Requirement R8 preserves the reliability objective of providing the SOL Methodology to the appropriate entities from Requirement R4 of FAC-011-3. Requirement R8 Part 8.1 mandates that an RC provide its SOL Methodology to each adjacent RC within its Interconnection. In Requirement R8 Part 8.2, PC, not Planning Authority, was used to be consistent with the Functional Model as well as to be consistent with TPL-001. Requirement R8 Part 8.2 also uses “responsible for planning” instead of “models any portion of” to identify those PCs and TPs who have a reliability-related need rather than a PC/TP who simply has acquired a model that contains a portion of the Reliability Coordinator Area, but does not plan for that area. Requirement R8 Part 8.4 differs from Requirement R8 Parts 8.1 through 8.3 in that it mandates that an RC provide its SOL Methodology to any requesting RC that indicates a reliability-related need within 30 calendar days of such request rather than prior to the effective date of the SOL Methodology.

Mapping Document

Project 2015-09 Establish and Communicate System Operating Limits

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
FAC-011-3, Requirement R1. The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall:	FAC-011-4, Requirement R1. Each Reliability Coordinator shall have a methodology for establishing SOLs ("SOL Methodology") within its Reliability Coordinator Area.	No change.
FAC-011-3, Requirement R1, R1.1. [This SOL Methodology shall] Be applicable for developing SOLs used in the operations horizon.	This requirement was removed.	The stated purpose of FAC-011-4 is "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." The title of FAC-011-4 is "System Operating Limits Methodology for the Operations Horizon". Therefore, every requirement in FAC-011-4 is intended for developing SOLs used in the operations horizon. Accordingly, there is no reliability-

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		related need to have a requirement specifying that the Reliability Coordinator's (RC's) SOL Methodology is applicable for developing SOLs used in the operations horizon.
FAC-011-3, Requirement R1, R1.2. [This SOL Methodology shall] State that SOLs shall not exceed associated Facility Ratings.	This requirement is addressed in proposed FAC-011-4 Requirement R2 in conjunction with the definitions for Operational Planning Analysis and Real-time Assessment in the NERC Glossary of Terms. FAC-011-4 Requirement R2: Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the applicable owner-provided 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. Operational Planning Analysis is defined in the NERC Glossary of Terms as *"An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for*	Facility Ratings to be used in operations as SOLs is addressed through FAC-011-4, Requirement R2. Facility Ratings that are determined per Requirement R2 are a required input for Operational Planning Analyses (OPA) and Real-time Assessments (RTA) per the definitions, and therefore address the analysis of system performance with respect to Facility Ratings. Facility Rating exceedances are determined through OPAs and RTAs.

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	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.)" Real-time Assessment is defined in the NERC Glossary of Terms 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*	

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	internal systems or through third-party services.)"	
FAC-011-3, Requirement R1, R1.3. [This SOL Methodology shall] Include a description of how to identify the subset of SOLs that qualify as IROLs.	FAC-011-4, Requirement R6 and Part 6.1. R6. Each Reliability Coordinator shall include in its SOL Methodology 6.1. A description of how to identify the subset of SOLs that qualify as IROLs.	The language from the approved standard was maintained in the proposed FAC-011-4.
FAC-011-3, Requirements R2, R2.1 and R2.2. R2. The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following: R2.1 In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.	These requirements are addressed in: 1. TOP and IRO requirements for TOPs and RCs to perform OPAs, to develop Operating Plans for SOL exceedances identified in those OPAs, to perform RTAs, and to implement Operating Plans to address SOL exceedances identified in those RTAs. 2. The definition of OPA and RTA 3. FAC-011-4, Requirement R4 addresses the establishment of stability limits and the associated performance requirements. 4. FAC-011-4 Requirement R6 and its Parts relating to IROLs.	"BES performance" as stated in FAC-011-3 Requirement R2 is not determined through SOLs in and of themselves. SOLs are an input into OPAs and RTAs. The OPA and RTA evaluation against those SOLs provide for reliable system performance by ensuring through these analyses/assessments that the system performs reliably in the pre- and post-Contingency states (i.e., that the system is within thermal (Facility Ratings), System Voltage Limits, and stability limits pre- and post-Contingency). If SOL exceedance is occurring, the system is not performing reliably. Per the Transmission Operator (TOP) standards, SOL exceedance triggers the development and

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
R2.2. Following the single Contingencies identified in Requirement R2, R2.2.1 - R2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.	5. The definition of IROL and the TOP and IRO standards that address operation within IROLs. 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 exceed any of its System Operating Limits (SOLs). TOP-001-4, Requirement R2: Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. TOP-001-4, Requirement R13: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. TOP-001-4, Requirement R14: Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL	implementation of an Operating Plan to address that SOL exceedance. The items in approved FAC-011-3, Requirement R2 and its sub-requirements are addressed through the related TOP standards that reference SOL exceedance. 1. Per TOP-002-4, Requirement R1, TOPs have OPAs to identify SOL exceedances. 2. Per TOP-002-4, Requirement R2, TOPs develop Operating Plans for SOL exceedances identified in the OPA. 3. Per TOP-001-3, Requirement R13, TOPs perform RTAs at least once every 30 minutes to identify SOL exceedances. 4. Per TOP-001-3, Requirement R14, TOPs implement Operating Plans to mitigate SOL exceedances. 5. Per IRO-008-2, Requirement R1, RCs perform OPAs to identify SOL and IROL exceedances.

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	exceedance identified as part of its Real-time monitoring or Real-time Assessment. IRO-008-2, Requirement R1: Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area. IRO-008-2, Requirement R2: Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. IRO-008-2, Requirement R4: Each Reliability Coordinator shall ensure that a Real-time	6. Per IRO-008-2, Requirement R2, RCs develop coordinated Operating Plans for SOL and IROL exceedances identified in its OPA. 7. Per IRO-008-2, Requirement R4, RCs perform RTAs at least once every 30 minutes to identify SOL and IROL exceedances. 8. Per IRO-008-2, Requirement R5, RCs notify TOPs and BAs of SOL or IROL exceedances identified in its RTA. The portion of FAC-011-3, Requirement R2, R2.1 that states *"In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages"* is addressed specifically by FAC-011-4 Requirement R4, Part 4.4 which requires that System conditions including any changes to System topology such as Facility outages are to be included as part of the process for determining stability limits. While stability

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	Assessment is performed at least once every 30 minutes. IRO-008-2, Requirement R5: Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area. Operational Planning Analysis is defined in the NERC Glossary of Terms 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*	limits are frequently dependent on system conditions and Facility outages, Facility Ratings and System Voltage Limits are not dependent on system conditions and Facility outages. However, system conditions and topology changes such as Facility outages are critical for determining whether or not Facility Ratings and System Voltage Limits are being exceeded for the pre- or post-Contingency state, which is accomplished through performing OPAs and RTAs that address expected and actual system conditions and Facility outages for the pre- and post-Contingency state. Regarding the stability portions of Requirement R2, R2.1 and R2.2: FAC-011-4, Requirement R4 improve reliability by requiring the RC's SOL Methodology to address several stability-related phenomena and associated performance criteria in its SOL Methodology, as seen in Requirement R4, Part 4.1.

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	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.)" Real-time Assessment is defined in the NERC Glossary of Terms 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.)"*	Requirement R4, Part 4.2 requires the RC's SOL Methodology to require that stability limits be established to meet those performance requirements. Furthermore, Requirement R4, Part 4.6 requires the RC's SOL Methodology to specify how the RC establishes stability limits when there is an impact to more than one TOP in its Reliability Coordinator Area RC's SOL Methodology. Requirement R4 works together with FAC-014-3, Requirement R2 which requires TOPs to establish SOLs in accordance with the RC's SOL Methodology and with FAC-014-3, Requirement R4 which requires the RC to establish stability limits that impact more than one TOP in its RC Area. Instability is also addressed through FAC-011-4, Requirement R6 which requires the RC's SOL Methodology contain a description of how to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs), and through FAC-014-3, Requirement R1 which requires the

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	FAC-011-4 Requirement R4: Each Reliability Coordinator shall include in its SOL Methodology the method for determining the stability limits to be used in operations. The method shall: 4.1. Specify stability performance criteria, including any margins applied. The criteria shall include the following: 4.1.1. steady-state voltage stability; 4.1.2. transient voltage response; 4.1.3. angular stability; 4.1.4. System damping. 4.2. Require that stability limits are established to meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5. 4.3. Describe how the Reliability Coordinator establishes stability limits when there is an impact to more than one Transmission Operator in its Reliability Coordinator Area.	RC to establish IROLs in accordance with its SOL Methodology. IRO-009-2, Requirement R3 requires the RC to act or direct others to act so that the magnitude and duration of an IROL exceedance is mitigated within the IROL's T_v, as identified in the Reliability Coordinator's Real-time monitoring or Real-time Assessment. Additionally, TOP-001-3, Requirement R12 requires that the TOP not operate outside any identified IROL for a continuous duration exceeding its associated IROL T_V.

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	4.4. Describe how instability risks are identified, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages; 4.5. Describe the level of detail that is required for the study model(s), including the extent of the Reliability Coordinator Area, as well as the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits. 4.6. Describe the allowed uses of Remedial Action Schemes (RAS) and other automatic post-Contingency mitigation actions. IROL is defined in the NERC Glossary of Terms as – *A System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System.*	

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	FAC-011-4, Requirement R6: Each Reliability Coordinator shall include in its SOL Methodology: 6.1. A description of how to identify the subset of SOLs that qualify as IROLs. 6.2. Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_V. FAC-014-3, Requirement R1: Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit Methodology (SOL Methodology). IRO-009-2, Requirement R3: Each Reliability Coordinator shall act or direct others to act so that the magnitude and duration of an	

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	IROL exceedance is mitigated within the IROL's T_V, as identified in the Reliability Coordinator's Real-time monitoring or Real-time Assessment. TOP-001-3, Requirement 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.	
FAC-011-3, Requirement R2, sub-requirements R2.2.1, R2.2.2, and R2.2.3 R2.2.1. Single line to ground or 3-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device. R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault. R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.	FAC-011-4, Requirement R5, Part 5.1.1 Loss of any 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 block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.	The requirements in approved FAC-011-3 were consolidated into a single requirement in proposed FAC-011-4.

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
FAC-011-3, Requirement R2.3, sub-requirements R2.3.1, R2.3.2, R2.3.3, and Requirement R2.4. R2.3 In determining the system's response to a single Contingency, the following shall be acceptable: R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area. R2.3.2. Interruption of other network customers, (a) only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or (b) if the real-time operating conditions are more adverse than anticipated in the corresponding studies R2.3.3. System reconfiguration through manual or automatic control or protection actions. R2.4 To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the	The reliability issues denoted in FAC-011-3 Requirement R2.3, sub-requirements R2.3.1, R2.3.2, R2.3.3, and R2.4 represent a combination of issues that are relevant to the establishment of SOLs and those that are relevant to "how the system is to be operated." The issues that pertain to the establishment of SOLs are addressed through FAC-011-4 Requirement R4 : R4. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the stability limits to be used in operations. The method shall: 4.1. Specify stability performance criteria, including any margins applied. The criteria shall include the following: 4.1.1. steady-state voltage stability; 4.1.2. transient voltage response; 4.1.3. angular stability; 4.1.4. System damping.	Requirement R2, R2.3 describes an acceptable System response to single Contingencies. These requirements are sub-requirements of Requirement R2, which addresses the establishment of SOLs that "provide a certain level of BES performance". "BES performance" as stated in FAC-011-3, Requirement R2 is not determined through SOLs in and of themselves. SOLs are an input into OPAs and RTAs. The OPA and RTA evaluation against those SOLs provide for reliable system performance by ensuring through these analyses/assessments that the system performs reliably in the pre- and post-Contingency states (i.e., that the system is within thermal (Facility Ratings), System Voltage Limits, and stability limits pre- and post-Contingency). If SOL exceedance is occurring, the system is not performing reliably. Per the TOP and IRO standards, RTAs must be performed at least once every 30 minutes. Accordingly, each new operating state is "studied" at least once every 30 minutes. Additionally, per the TOP

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
transmission system, and the transmission system topology.	4.2. Require that stability limits are established to meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5. 4.3. Describe how the Reliability Coordinator establishes stability limits when there is an impact to more than one Transmission Operator in its Reliability Coordinator Area. 4.4. Describe how instability risks are identified, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages; 4.5. Describe the level of detail that is required for the study model(s), including the extent of the Reliability Coordinator Area, as well as the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits. 4.6. Describe the allowed uses of Remedial Action Schemes (RAS) and other	standards, SOL exceedance triggers the development and implementation of an Operating Plan to address that SOL exceedance. Insofar as the issues in FAC-011-3, Requirement R2, R2.3 and R2.4 correlate to the establishment of SOLs, automatic control actions relevant to the establishment of stability limits are addressed in FAC-011-4 Requirement R4, Part 4.6 which requires the SOL Methodology to describe the allowed uses of Remedial Action Schemes (RAS) and other automatic post-Contingency mitigation actions as part of stability limit establishment. Accordingly, any RAS or automatic mitigation scheme (which includes those that interrupt customers or reconfigure the system) are required to be reflected in the establishment of stability limits per Requirement R4, Part 4.6. Furthermore, per Requirement R4, Part 4.4, stability limits are required to take into consideration the configuration of the system, which may include any necessary

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	automatic post-Contingency mitigation actions. The issues that are more centric to "how the system is to be operated" are more appropriately addressed in the development and implementation of Operating Plans as denoted in the following standards: 1. 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) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. 2. TOP-002-4, Requirement R3: Each Transmission Operator shall notify entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s). 3. TOP-002-4, Requirement R6: Each Transmission Operator shall provide	manual actions taken by the System Operator to configure the system in a manner that supports the use of a given stability limit. However, insofar as FAC-011-3, Requirement R2, R2.3 and R2.4 correlate to "how the system is to be operated", the operational decisions related to customer interruption and system reconfiguration are governed by the Operating Plan, if such actions are necessary to address SOL exceedance. The need for making system adjustments to prepare for the next Contingency is standard operational practice and does not need to be specified or required by the Reliability standards. Any such actions related to the interruption of customers, reconfiguration of the system, or operational preparations for the next Contingency are expected to be included in an Operating Plan, if such actions are required by System Operators to address SOL exceedances.

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	its Operating Plan(s) for next-day operations identified in Requirement R2 to its Reliability Coordinator. 4. TOP-012-3, 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. 5. IRO-008-2, Requirement R2: Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. 6. IRO-008-2, Requirement R3: Each Reliability Coordinator shall notify	In the current body of TOP and IRO reliability standards, the Operating Plan is the mechanism for addressing SOL exceedances. The mitigation actions that System Operators take to prevent or address SOL exceedances are expected to be contained within the Operating Plan. TOPs need to have the flexibility in their Operating Plan to address the wide-ranging operational issues they may encounter. There is no reliability need for reliability standards to provide such highly prescriptive requirements which specify how TOPs are to operate the system. Because the development and implementation of Operating Plans is addressed in the current body of reliability standards, reliability is not compromised by the removal of FAC-011-3, Requirement R2, R2.3 and R2.4. Any concepts in this section may need to be retained are better suited in a Reliability Guideline (e.g., Reliability Guideline for the development of Operating Plans) rather

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	impacted entities identified in its Operating Plan(s) cited in Requirement R2 as to their role in such plan(s). 7. IRO-008-2, Requirement R5: Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated.	than a NERC Reliability Standard requirement.
FAC-011-3, Requirement R3, R3.1 R3. The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:	FAC-011-4, Requirement R4, Part 4.5 R4. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the stability limits to be used in operations. The method shall: 4.5. Describe the level of detail that is required for the study model(s), including	FAC-011-3, Requirement R3, R3.1 and R3.4 both address the study model. These two requirements are addressed with the single requirement in proposed FAC-011-4, Requirement R4, Part 4.5. Facility Ratings are created and provided through FAC-008 and further examined

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
R3.1 Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)	the extent of the Reliability Coordinator Area, as well as the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.	through FAC-011-4, Requirement R2. System Voltage Limits are created per FAC-011-4, Requirement R3. Neither of these types of SOLs are necessarily a byproduct of a "study" or study model. As a result, no study model reference is needed in FAC-011-4 for Facility Ratings or System Voltage Limits. However, for those RCs or TOPs that determine stability limits, a study model is needed to perform the "study". Therefore, the level of detail of the study model falls under the requirement associated with establishing stability limits (R4). FAC-011-4, Requirement R4, Part 4.5 affords the RC with the flexibility to the extent of the modeling area (including other RC areas) that must be modeled to reflect the varying needs for different types of stability limits (e.g. local single unit stability up to wide-area or inter-area instability). Part 4.5 acknowledges that some types of localized stability issues do not require a model of

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		the entire RC area to establish certain types of stability limits.
FAC-011-3, Requirement R3, R3.2 R3.2 [The RC's SOL Methodology shall include] Selection of applicable Contingencies	FAC-011-4, Requirement R5 R5. Each Reliability Coordinator shall include in its SOL Methodology the method for identifying the single Contingencies and multiple Contingencies for use in determining stability limits and performing Operational Planning Analyses (OPAs) and Real-time Assessments (RTAs). The method shall include: 5.1. The following list of single Contingency events for use in determining stability limits and performing OPAs and RTAs: 5.1.1. Loss of any of the following, either by single phase to ground or three phase Fault (whichever is more severe) with normal clearing, or without a Fault: • generator; • transmission circuit; • transformer;	All requirements regarding Contingencies are consolidated and addressed in proposed FAC-011-4, Requirement R5.

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	• shunt device; • single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system. 5.2. Any additional types of single Contingency events identified for use in determining stability limits, or for use in performing OPAs and RTAs. 5.3. Any types of multiple Contingency events identified for use in determining stability limits, or for use in performing OPAs and RTAs. 5.4. The method for considering the Contingency events provided by the Planning Coordinator in accordance with FAC-015-1 Requirement R6 to identify the Contingencies for use in determining stability limits.	
FAC-011-3, Requirement R3, R3.3 and R3.3.1. R3.3 [The RC's SOL Methodology shall include] A process for determining which of the stability limits associated with the list of	FAC-011-4, Requirement R5, Part 5.4 R5. Each Reliability Coordinator shall include in its SOL Methodology the method for identifying the single Contingencies and	FAC-011-4, Requirement R5, Part 5.4 and FAC-015-1 Requirement R6 address the reliability objective in FAC-011-3, Requirement R3, R3.3.1.

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
multiple contingencies (provided by the Planning Authority in accordance with FAC-014, Requirement 6) are applicable for use in the operating horizon given the actual or expected system conditions. R3.3.1. This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies.	multiple Contingencies for use in determining stability limits and performing Operational Planning Analyses (OPAs) and Real-time Assessments (RTAs). The method shall include: 5.4. The method for considering the Contingency events provided by the Planning Coordinator in accordance with FAC-015-1 Requirement R6 to identify the Contingencies for use in determining stability limits. FAC-015-1 Requirement R6: R6. Each Planning Coordinator shall communicate any instability, Cascading or uncontrolled separation identified in either its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment to each impacted Reliability Coordinator and Transmission Operator. This communication shall include:	In FAC-015-1, Requirement R6, the Planning Coordinator is required to identify and communicate any instability, Cascading, or uncontrolled separation, as well as the related information contained in the Parts of Requirement R6, to the RC and associated TOPs. Once the RC receives this information, the RC then applies the method required by FAC-011-4, Requirement R5, Part 5.4 for considering those Contingencies for use in determining stability limits. These requirements collectively address the reliability objectives of FAC-011-3, Requirement R3, R3.1.

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	6.1 The type of instability identified (e.g., voltage collapse, angular instability, transient voltage dip criteria violation); 6.2 The associated stability criteria used as part of determining the instability; 6.3 The associated Contingency(ies) which result(s) in the instability, Cascading or uncontrolled separation; 6.4 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 required to address the instability, Cascading or uncontrolled separation; 6.5 Any Corrective Action Plan associated with the instability, Cascading or uncontrolled separation.	
FAC-011-3, Requirement 3, R3.4. R3.4 [The RC's SOL Methodology shall include] Level of detail of system models used to determine SOLs.	FAC-011-4, Requirement R4, Part 4.5 R4. Each Reliability Coordinator shall include in its SOL Methodology the method	Reference the explanation provided for FAC-011-3, Requirement R3, R3.1.

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	for determining the stability limits to be used in operations. The method shall: 4.5. Describe the level of detail that is required for the study model(s), including the extent of the Reliability Coordinator Area, as well as the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.	
FAC-011-3, Requirement R3, R3.5. R3.5 [The RC's SOL Methodology shall include] Allowed uses of Remedial Action Schemes.	FAC-011-4, Requirement R4, Part 4.6 R4. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the stability limits to be used in operations. The method shall: 4.6. Describe the allowed uses of Remedial Action Schemes (RAS) and other automatic post-Contingency mitigation actions[1]. Footnote 1 states "The planned use of underfrequency load-shedding (UFLS) is not allowed in the establishment of stability limits."	FAC-011-3, Requirement R3, R3.5 was carried over into FAC-011-4, Requirement R4, Part 4.6. The requirement has been clarified by including other automatic mitigation actions that are not a RAS, for example UVLS.

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
FAC-011-3, Requirement R3, R3.6. R3.6 [The RC's SOL Methodology shall include] Anticipated transmission system configuration, generation dispatch and Load level	FAC-011-4, Requirement R4, Part 4.4: R4. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the stability limits to be used in operations. The method shall: 4.4. Describe how instability risks are identified, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages; 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 exceed any of its System Operating Limits (SOLs). IRO-008-2, Requirement R1: Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating	The requirements in FAC-011-3, Requirement R3, R3.6 are addressed in proposed FAC-011-4, Requirement R4, Part 4.4. Part 4.4 was included as a Part to Requirement R4 because the information is relevant to the establishment of stability limits. Facility Ratings are created and provided through FAC-008 and further examined through FAC-011-4, Requirement R2, and System Voltage Limits are created through FAC-011-4, Requirement R3. Neither of these types of SOLs are necessarily a byproduct of a "study" or study model that requires inclusion of the items in FAC-011-3, Requirement R3, R3.6. Additionally, TOP-002-4, Requirement R1 and IRO-008-2, Requirement R1 require the TOP and the RC respectively to have/perform an OPA. Per the definition of OPA, the OPA shall reflect applicable inputs which include the

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	Reliability Limits (IROLs) within its Wide Area. Operational Planning Analysis is defined in the NERC Glossary of Terms 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.)"*	items required by FAC-011-3, Requirement R3, R3.6. Accordingly, when stability limits include the information required in Requirement R4, and the TOPs and RCs perform their required OPAs, the information in FAC-011-3, Requirement R3, R3.6 is inherently addressed.
FAC-011-3, Requirement R3, R3.7. R3.7 [The RC's SOL Methodology shall include] Criteria for determining when violating a SOL qualifies as an Interconnection Reliability	FAC-011-4, Requirement R6, Part 6.2 R6.2 Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and	The reliability objective of FAC-011-3, Requirement R3, R3.7 was carried over into FAC-011-4, Requirement R6, Part 6.2.

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
Operating Limit (IROL) and criteria for developing any associated IROL T_V.	criteria for developing any associated IROL T_V.	
FAC-011-3, Requirement R4 and Requirement R4.1: R4. The Reliability Coordinator shall issue its SOL Methodology and any changes to that methodology, prior to the effectiveness of the Methodology or of a change to the Methodology, to all of the following: R4.1. Each adjacent Reliability Coordinator and each Reliability Coordinator that indicated it has a reliability-related need for the methodology.	FAC-011-4, Requirement R8, Parts 8.1 and 8.4: R8. Each Reliability Coordinator shall provide its new or revised SOL Methodology to: 8.1. Each adjacent Reliability Coordinator within its Interconnection prior to the effective date of the SOL Methodology; 8.4. Each requesting Reliability Coordinator that indicates a reliability-related need and is not considered adjacent in Part 8.1, within 30 calendar days of receiving the request.	The reliability objective of FAC-011-3, Requirement R4 was carried over to FAC-011-4, Requirement R8, Parts 8.1 and 8.4 Clarifications were made in Part 8.1 that adjacent RCs include those within an Interconnection. This was added to clarify the intent of adjacent RCs for the purposes of communicating SOL Methodologies. These adjacent RCs are required to receive the SOL Methodology prior to the effective date of the Methodology because they can be directly impacted by it. Non-adjacent RCs, which are addressed in Part 8.4, do not require communication of the SOL Methodology prior to its effective date because these RCs are less likely to be directly impacted; however, provisions are made with Part 8.4 for non-adjacent RCs to obtain the SOL Methodology within 30 days of the request if they indicate a reliability-related need for it.

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
FAC-011-3, Requirement R4, R4.2 R4.2 [communicate the SOL Methodology to] Each Planning Authority and Transmission Planner that models any portion of the Reliability Coordinator's Reliability Coordinator Area.	FAC-011-4, Requirement R8, Part 8.2 R8. Each Reliability Coordinator shall provide its new or revised SOL Methodology to: 8.2. Each Planning Coordinator and Transmission Planner responsible for planning any portion of the Reliability Coordinator Area prior to the effective date of the SOL Methodology;	The language was changed to better reflect the intent of the requirement. The requirement is intended to addresses PCs and TPs that are responsible for planning within the RC Area.
FAC-011-3, Requirement R4, R4.3 R4.3 [communicate the SOL Methodology to] Each Transmission Operator that operates in the Reliability Coordinator Area.	FAC-011-4, Requirement R8, Part 8.3 R8. Each Reliability Coordinator shall provide its new or revised SOL Methodology to: 8.3. Each Transmission Operator within its Reliability Coordinator Area prior to the effective date of the SOL Methodology;	The reliability objective of FAC-011-3, Requirement R4, R4.3 was carried over to FAC-011-4, Requirement R8, Part 8.3.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Violation Risk Factor and Violation Severity Level Justifications

FAC-011-4 System Operating Limits Methodology for the Operations Horizon

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Reliability Standard FAC-011-4 System Operating Limits (SOL) Methodology for the Operations Horizon. 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 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 FAC-011-4 Requirement R1	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard FAC-013-2, Requirement R1.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Not having a methodology for establishing SOLs has the potential unintended consequence of creating inconsistencies in establishing SOLs which could directly affect the electrical state or the capability of the Bulk Electric System (BES), or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-	The requirement contains one objective, therefore a single VRF is assigned.

mingle More than One Obligation	

VSLs for FAC-011-4, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator did not have a SOL Methodology for establishing SOLs within its Reliability Coordinator Area.

VSL Justifications for FAC-011-4, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-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 requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
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.

VRF Justifications for FAC-011-4 Requirement R2	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard FAC-008-3, Requirements R2 and R3.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The establishment of improper Facility Ratings could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Reliability Coordinator included in its SOL Methodology the method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations but the method did not address the use of common Facility Ratings between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area.	The Reliability Coordinator did not include in its SOL Methodology the method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations.

VSL Justifications for FAC-011-4, 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 R1 sub-requirement R1.2. Therefore, the proposed VSLs do not have the unintended consequence of lowering 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 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.

VRF Justifications for FAC-011-4 Requirement R3	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard FAC-008-3, Requirements R2 and R3 which requires development of a methodology to determine certain ratings/limits.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The establishment of incorrect System Voltage Limits could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator failed to incorporate one of the Parts of Requirement R3 into its SOL Methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R3 into its SOL Methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R3 into its SOL Methodology.	The Reliability Coordinator failed to incorporate four or more of the Parts of Requirement R3 into its SOL Methodology.

VSL Justifications for FAC-011-4, Requirement R3	
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 R1 and Requirement R2. Therefore, the proposed VSLs do not have the unintended consequence of lowering 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 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.

VRF Justifications for FAC-011-4 Requirement R4	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard FAC-008-3, Requirements R2 and R3 which requires development of a methodology to determine certain ratings/limits.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The establishment of incorrect stability limits could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator failed to incorporate one of the Parts of Requirement R4 into its SOL Methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R4 into its SOL Methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R4 into its SOL Methodology.	The Reliability Coordinator failed to incorporate four or more of the Parts of Requirement R4 into its SOL Methodology.

VSL Justifications for FAC-011-4, Requirement R4	
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 R1 and Requirement R2. Therefore, the proposed VSLs do not have the unintended consequence of lowering 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 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.

VRF Justifications for FAC-011-4 Requirement R5	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard TPL-001-4, Requirement R3, Part 3.4, which requires development of a list of contingencies to be evaluated for System performance.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Incorrectly identifying the single Contingencies and multiple Contingencies for use in determining stability limits and performing Operational Planning Analyses (OPAs) and Real-time Assessments (RTAs) could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
N/A	The Reliability Coordinator failed to incorporate one of the Parts 5.2, 5.3 or 5.4 of Requirement R5 into its SOL Methodology.	The Reliability Coordinator failed to incorporate two of the Parts 5.2, 5.3, or 5.4 of Requirement R5 into its SOL Methodology.	The Reliability Coordinator failed to incorporate Part 5.1 of Requirement R5 into its SOL Methodology. OR The Reliability Coordinator failed to incorporate Parts 5.2, 5.3, and 5.4 of Requirement R5 into its SOL Methodology.

VSL Justifications for FAC-011-4, Requirement R5	
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 R3, sub-requirements R3.2, R3.3, and R3.3.1. Therefore, the proposed VSLs do not have the unintended consequence of lowering 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 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.

VRF Justifications for FAC-011-4 Requirement R6	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of High for this requirement is consistent with approved Reliability Standard FAC-014-2, Requirements R1, R3, and R4 which requires development of Interconnection Reliability Operating Limits (IROLs) to be consistent with a methodology.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failing to correctly identify an IROL could directly cause or contribute to BES instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Reliability Coordinator failed to include Part 6.1 (a description of how to identify the subset of SOLs that qualify as IROLs) in its SOL Methodology. OR The Reliability Coordinator failed to include Part 6.2 (a criteria for determining when violating a SOL qualifies as an IROL) in its SOL Methodology. OR The Reliability Coordinator failed to include Part 6.2 (criteria for developing any associated IROL T_v) in its SOL Methodology.	The Reliability Coordinator failed to include Parts 6.1 and 6.2 in its SOL Methodology.

VSL Justifications for FAC-011-4, Requirement R6	
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 R1, sub-requirement R1.3 and Requirement R3, sub-requirement R3.7. Therefore, the proposed VSLs do not have the unintended consequence of lowering 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 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.

VRF Justifications for FAC-011-4 Requirement R7	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements (Parts) so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved other standards in the BAL, COM, EOP, IRO, and TOP families that require notification to other entities for situational awareness of the BES.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failure to communicate identified SOLs could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Reliability Coordinator did not include in its SOL Methodology the periodicity of SOL communications for Transmission Operators to communicate SOLs the Transmission Operator established.	The Reliability Coordinator did not include in its SOL Methodology the method for Transmission Operators to communicate SOLs it established or the periodicity of SOL communication.

VSL Justifications for FAC-011-4, Requirement R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The proposed VSLs do not lower 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 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.

VRF Justifications for FAC-011-4 Requirement R8	
Proposed VRF	**Lower**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of lower for this requirement is consistent with approved Reliability Standard FAC-010-3, Requirement R4, FAC-011-3, Requirement R4, and FAC-013-2, Requirement R2 which requires notification of a new or revised methodology to other entities.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failing to provide its SOL methodology to entities within and adjacent to its Reliability Coordinator Area could affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R8			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Part 8.4 but was late by less than or equal to 10 calendar days.	The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Part 8.4, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	The Reliability Coordinator failed to provide its new or revised SOL Methodology to one of the parties specified in Parts 8.1 through 8.3. OR The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Part 8.4, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	The Reliability Coordinator failed to provide its new or revised SOL Methodology to two or more of the parties specified in Parts 8.1 through 8.3. OR The Reliability Coordinator failed to provide its new or revised SOL Methodology to one or more of the parties specified in Parts 8.1 through 8.3 prior to the effective date of the SOL Methodology. OR The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Part 8.4, but was late by more than 30 calendar days. OR The Reliability Coordinator failed to provide its new or revised SOL Methodology to a requesting Reliability

			Coordinator in accordance with Part 8.4.

VSL Justifications for FAC-011-4, Requirement R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs map to the currently-effective FAC-011-3 Requirement R4. The proposed VSLs do not lower 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 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.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the Board of Trustees.

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
Draft Reliability Standard posted for Informal Comment Period	07/14/16 – 08/12/16

Anticipated Actions	Date
45-day formal comment period with ballot	September 2017 – October 2017
45-day formal comment period with additional ballot	January 2018 – February 2018
10-day final ballot	February 2018
NERC Board (Board) adoption	May 2018

A. Introduction

1. **Title:** Establish and Communicate System Operating Limits

2. **Number:** FAC-014-2~~2~~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

~~**1.1.** Planning Authority~~

~~**1.2.** Transmission Planner~~

4.1.2. Transmission Operator

~~**2. Effective Date:** April 29, 2009~~

5. Effective Date: See Implementation Plan for Project 2015-09.

B. Requirements and Measures

~~The~~

R1. Each Reliability Coordinator shall ~~ensure that SOLs, including~~ establish Interconnection Reliability Operating Limits (IROLs~~),~~) for its Reliability Coordinator Area ~~are~~in accordance with its System Operating Limit Methodology (SOL Methodology). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the Reliability Coordinator established ~~and that the SOLs (including Interconnection Reliability Operating Limits) are consistent~~IROLs in accordance with ~~its~~it SOL Methodology.

R2. ~~The~~Each Transmission Operator shall establish ~~SOLs (as directed by its Reliability Coordinator~~System Operating Limits (SOLs) for its portion of the Reliability Coordinator Area ~~that are consistent~~in accordance with its Reliability Coordinator's SOL Methodology. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the Transmission Operator established SOLs in accordance with its Reliability Coordinator's SOL Methodology.

~~**R1.**~~**R3.** The ~~Planning Authority~~Transmission Operator shall ~~establish SOLs, including IROLs, for~~provide its ~~Planning Authority Area that are consistent~~SOLs to its Reliability Coordinator in accordance with its Reliability Coordinator's SOL Methodology. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

M3. ~~The Transmission Planner shall establish SOLs, including IROLs, for its~~Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the Transmission ~~Planning Area that are consistent~~Operator provided its SOLs in accordance with its ~~Planning Authority's~~Reliability Coordinator's SOL Methodology.

~~**R1.** The Reliability Coordinator, Planning Authority, and Transmission Planner shall each provide its SOLs and IROLs to those entities that have a reliability-related need for those limits and provide a written request that includes a schedule for delivery of those limits as follows:~~

R4. ~~The~~Each Reliability Coordinator shall ~~provide its SOLs~~establish stability limits to be used in operations when the limit impacts more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL Methodology. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the Reliability Coordinator established stability limits in accordance with Requirement R4.

R5. Each Reliability Coordinator shall provide: *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

5.1. Each Planning Coordinator within its Reliability Coordinator Area, SOLs for its Reliability Coordinator Area (including the subset of SOLs that are IROLs) ~~to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and~~ at least once every twelve calendar months.

~~**1.1.**~~**5.2.** Each impacted Planning ~~Authorities~~Coordinator within its Reliability Coordinator Area~~. For~~, the following information for each established stability limit and each established IROL~~, the Reliability Coordinator shall provide the following supporting information~~ at least once every twelve calendar months:

5.2.1. The value of the stability limit or IROL;

~~**1.1.1.**~~**5.2.2.** Identification ~~and status~~ of the ~~associated Facility (or group of~~ Facilities~~)~~ that ~~is (~~are~~)~~ critical to the derivation of the stability limit or IROL~~.~~;

~~**1.1.2.**~~**5.2.3.** The ~~value of the IROL and its~~ associated IROL T_V~~.~~ for any IROL;

~~**1.1.3.**~~**5.2.4.** The associated Contingency(ies~~).~~); and

~~**1.1.4.**~~**5.2.5.** The type of limitation represented by the stability limit or IROL (*e.g.*, voltage collapse, angular stability).

5.3. ~~The~~Each impacted Transmission Operator ~~shall provide any SOLs it developed~~within its Reliability Coordinator Area, the value of the stability limits established pursuant to ~~its Reliability Coordinator~~Requirement R4 and each IROL established pursuant to Requirement R1, in an agreed upon time frame

necessary for inclusion in the Transmission ~~Service Providers that share its portion of the~~ Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

~~1.2.~~5.4. Each impacted Transmission Operator within its Reliability Coordinator Area, the information identified in Requirement R5 Parts 5.2.2 – 5.2.5 for each established stability limit or each IROL, and any updates to that information within an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses.

~~**R1.1.** The Planning Authority shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Planning Authorities, and to Transmission Planners, Transmission Service Providers, Transmission Operators and Reliability Coordinators that work within its Planning Authority Area.~~

~~**R1.2.** The Transmission Planner shall provide its SOLs (including the subset of SOLs that are IROLs) to its Planning Authority, Reliability Coordinators, Transmission Operators, and Transmission Service Providers that work within its Transmission Planning Area and to adjacent Transmission Planners.~~

~~**R2.** The Planning Authority shall identify the subset of multiple contingencies (if any), from Reliability Standard TPL-003 which result in stability limits.~~

~~**R2.1.** The Planning Authority shall provide this list of multiple contingencies and the associated stability limits to the Reliability Coordinators that monitor the facilities associated with these contingencies and limits.~~

~~**R2.2.** If the Planning Authority does not identify any stability-related multiple contingencies, the Planning Authority shall so notify the~~ Each requesting Transmission Operator within its Reliability Coordinator~~.~~

~~A. Measures~~

5.5. ~~The~~ Area, requested SOL information for its Reliability Coordinator~~, Planning Authority, Transmission Operator, and Transmission Planner shall each be able~~ Area, on a mutually agreed upon schedule.

~~**M4.**~~ Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that ~~it developed its SOLs (including the subset of SOLs that are IROLs) consistent with the applicable SOL Methodology in accordance with Requirements 1 through 4.~~

~~**M5.** The~~ the Reliability Coordinator~~, Planning Authority, Transmission Operator, and Transmission Planner shall each have evidence that its SOLs (including the subset of SOLs that are IROLs) were supplied in accordance with schedules supplied by the requestors of such SOLs as specified in Requirement 5.~~

~~**M6.**~~**M5.** ~~The Planning Authority shall have evidence it identified a list of multiple contingencies (if any) and their associated stability limits and~~ provided the ~~list and the limits to its Reliability Coordinators~~information in accordance with Requirement ~~6~~R5.

R6. Each Reliability Coordinator that is impacted by an IROL shall provide Transmission Owners and Generation Owners within its Reliability Coordinator Area a list of Facilities owned by that entity that are critical to the derivation of the IROL. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M6. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the Reliability Coordinator provided the list of Facilities in accordance with Requirement R6.

C. Compliance

1. Compliance Monitoring Process

~~**2.1. Compliance Monitoring Responsibility**~~

~~Regional Reliability Organization~~

~~**2.2. Compliance Monitoring Period and Reset Time Frame**~~

~~The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each verify compliance through self-certification submitted to its Compliance Monitor annually. The Compliance Monitor may conduct a targeted audit once in each calendar year (January – December) and an investigation upon a complaint to assess performance.~~

~~The Performance-Reset Period shall be twelve months from the last finding of non-compliance.~~

~~**2.3. Data Retention**~~

~~The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each keep documentation for 12 months. In addition, entities found non-compliant shall keep information related to non-compliance until found compliant.~~

~~The Compliance Monitor shall keep the last audit and all subsequent compliance records.~~

~~**2.4. Additional Compliance Information**~~

~~The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each make the following available for inspection during a targeted audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:~~

~~**2.4.1** SOL Methodology(ies)~~

~~**2.4.2** SOLs, including the subset of SOLs that are IROLs and the IROLs supporting information~~

~~**2.4.3** Evidence that SOLs were distributed~~

~~**2.4.4** Evidence that a list of stability-related multiple contingencies and their associated limits were distributed~~

~~**2.4.5** Distribution schedules provided by entities that requested SOLs~~

1.1. Compliance Enforcement Authority:

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

1.2. Evidence Retention:

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

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

- The Reliability Coordinator or Transmission Operator shall keep data or evidence of Requirements R1 through R6 for the current year plus the previous 12 calendar months.

1.3. Compliance Monitoring and Enforcement Program

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

Violation Severity Levels~~:~~

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	~~There are SOLs, for the Reliability Coordinator Area, but from 1% up to but less than 25% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)~~N/A	~~There are SOLs, for the Reliability Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)~~N/A	~~There are SOLs, for the Reliability Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)~~N/A	~~There are SOLs~~The Reliability Coordinator did not establish Interconnection Reliability Operating Limits (IROLs) for ~~the~~its Reliability Coordinator Area~~, but 75% or more of these SOLs are inconsistent~~ in accordance with ~~the Reliability Coordinator's~~ its System Operating Limit Methodology ("SOL Methodology~~. (R1)~~") as established in FAC-011-4.
R2.	~~The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but from 1% up to but less than 25% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)~~N/A	~~The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)~~N/A	~~The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)~~N/A	The Transmission Operator ~~has established~~did not establish SOLs for its portion of the Reliability Coordinator Area~~, but 75% or more of these SOLs are inconsistent~~ in accordance with ~~the~~its Reliability Coordinator's SOL Methodology~~. (R2)~~
R3.	~~There are SOLs, for the Planning Coordinator Area, but from 1% up to, but less than,~~	~~There are SOLs, for the Planning Coordinator Area, but 25% or more, but less than 50%~~	~~There are~~The Transmission Operator provided its SOLs	~~There are SOLs, for the Planning Coordinator Area, but 75% or more of these SOLs are~~

	~~25% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)~~N/A	~~of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)~~N/A	~~for the Planning~~to its Reliability Coordinator ~~Area~~, but ~~50% or more, but less than 75% of these~~did not provide its SOLs ~~are inconsistent with~~at the periodicity at which the ~~Planning Coordinator's SOL Methodology. (R3)~~RC needs such information to perform its reliability functions.	~~inconsistent with the Planning Coordinator's SOL Methodology. (R3)~~The Transmission Operator did not provide its SOLs to its Reliability Coordinator.
R4.	~~The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but up to 25% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)~~N/A	~~The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)~~N/A	~~The Transmission Planner has established SOLs for its portion of the Reliability Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)~~N/A	The Reliability Coordinator did not determine stability limits to be used in operations when the limit impacts more than one Transmission ~~Planner has established SOLs for~~Operator in its ~~portion of the Planning~~Reliability Coordinator Area~~, but 75% or more of these SOLs are inconsistent~~ in accordance with ~~the Planning Coordinator's~~its SOL Methodology. ~~(R4)~~
R5 ~~.~~	~~The responsible entity provided its SOLs (including the subset of SOLs that are IROLs) to all the requesting entities but missed meeting one or more of the schedules by less than 15 calendar days. (R5)~~	~~One of the following:~~ ~~The responsible entity provided its SOLs (including the subset of SOLs that are IROLs) to all but one of the requesting~~	~~One of the following:~~ ~~The responsible entity provided its SOLs (including the subset of SOLs that are IROLs) to all but two of the requesting~~	~~One of the following:~~ ~~The responsible entity failed to provide its SOLs (including the subset of SOLs that are IROLs) to more than two of the requesting entities within 45~~

	The Reliability Coordinator did not provide one of the items listed in Requirement R5, Parts 5.1 through 5.5.	~~entities within the schedules provided. (R5)~~ ~~Or~~ ~~The responsible entity provided its SOLs to all the requesting entities but missed meeting one or more of the schedules for 15 or more but less than 30 calendar days. (R5)~~ ~~OR~~ ~~The supporting information provided with the IROLs does not address 5.1.4~~ The Reliability Coordinator did not provide two of the items listed in Requirement R5, Parts 5.1 through 5.5.	~~entities within the schedules provided. (R5)~~ ~~Or~~ ~~The responsible entity provided its SOLs to all the requesting entities but missed meeting one or more of the schedules for 30 or more but less than 45 calendar days. (R5)~~ ~~OR~~ ~~The supporting information provided with the IROLs does not address 5.1.3~~ The Reliability Coordinator did not provide three of the items listed in Requirement R5, Parts 5.1 through 5.5.	~~calendar days of the associated schedules. (R5)~~ ~~OR~~ ~~The supporting information provided with the IROLs does not address 5.1.1 and 5.1.2.~~ The Reliability Coordinator did not provide four or more of the items listed in Requirement R5, Parts 5.1 through 5.5.
R6 ~~:~~	~~The Planning Authority failed to notify the Reliability Coordinator in accordance with R6.2~~N/A	~~Not applicable.~~N/A	~~The Planning Authority identified the subset of multiple contingencies which result in stability limits **but** did not provide the list of multiple contingencies and associated limits to one Reliability Coordinator that monitors the Facilities associated with these limits. (R6.1)~~ N/A	~~The Planning Authority did not identify the subset of multiple contingencies which result in stability limits. (R6)~~ ~~OR~~ ~~The Planning Authority identified the subset of multiple contingencies which result in stability limits **but** did not provide the list of multiple contingencies and associated limits to more than one Reliability Coordinator that monitors the Facilities associated with these limits. (R6.1)~~The Reliability Coordinator with an established IROL, or the

				Reliability Coordinator impacted by a neighboring Reliability Coordinator IROL, did not provide Transmission Owners or Generation Owners within its Reliability Coordinator Area a list of Facilities owned by that entity that are critical to the derivation of the IROL.

D. Regional ~~Differences~~Variances

None ~~identified.~~

E. Interpretations

None

F. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
2		Changed the effective date to January 1, 2009 Replaced Levels of Non-compliance with Violation Severity Levels	Revised
2	June 24, 2008	Adopted by Board of Trustees: FERC Order	Revised
2	January 22, 2010	Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order	Update
2	April 29, 2015 – July 23, 2015	Incorrectly included TOP as the applicable function for Requirement R5. 7/23/15: Corrected to designate R5 as: RC, PA and TP.	Revised
3		Project 2015-09 Adopt revised standard.	Revision

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Rationales for FAC-014-3

September 2017

Requirement R1

Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit methodology (SOL Methodology).

Rationale R1

Reliability Standard FAC-014-2 Requirement R1 requires that the Reliability Coordinator (RC) ensure that System Operating Limits (SOLs), including Interconnection Reliability Operating Limits (IROLs), for its RC Area are established and that the SOLs (including IROLs) are consistent with its SOL Methodology.

Furthermore, Requirement R2 of FAC-014-2 requires the Transmission Operator (TOP) to establish SOLs consistent with its RC's SOL Methodology.

Under this structure the RC is responsible for ensuring that SOLs established by the TOP, per Requirement R2, are consistent with the RC's SOL Methodology. This creates a situation where the RC is responsible for "ensuring" the actions of the TOP.

Accordingly, if the TOP does not establish SOLs per its RC's SOL Methodology, then 1) the TOP is in violation of Requirement R2, and 2) the RC by default is in violation of Requirement R1 because the RC did not ensure that the TOP's SOL was consistent with its SOL Methodology.

The proposed revision addresses this issue and clarifies the appropriate responsibilities of the respective functional entities. 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.

Requirement R2

Each Transmission Operator shall establish System Operating Limits (SOL) for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL Methodology.

Rationale R2

Requirement R2 preserves the intent of Requirement R2 of FAC-014-2.

The standard drafting team (SDT) removed language from the existing FAC-014-2 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 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 SDT has removed the unnecessary and potentially confusing language. The

proposed language makes clear that the TOP is the entity responsible for establishing SOLs, and that these SOLs must be established in accordance with the RC's SOL Methodology.

Requirement R3

The Transmission Operator shall provide its SOLs to its Reliability Coordinator in accordance with its Reliability Coordinator's SOL Methodology.

Rationale R3

Requirement R3 requires TOPs to provide the SOLs it established (under requirement R2) to the RC in accordance with the RC's SOL Methodology. This requirement is a companion requirement to FAC-011-4 Requirement R7, which states: "Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to communicate SOLs it established to its RC(s). The method shall address the periodicity of SOL communication." These two requirements work together to ensure that SOLs established by the TOP in accordance with the RC's SOL Methodology are communicated to the RC in a timely manner.

The SDT recognizes that the provision of SOL information from the TOP to the RC may also be addressed via IRO-010-2, but the proposed requirement may also be utilized for SOL information other than what is utilized for Operational Planning Analysis (OPA)/ Real-time Assessment (RTA)/ Real-time monitoring. In such instances, the timing requirements should be coordinated between the RC's SOL methodology and the data specification document.

Requirement R4

Each Reliability Coordinator shall establish stability limits to be used in operations when the limit impacts more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL Methodology.

Rationale R4

Requirement R4 requires that the RC establish stability limits to be used in operations when the limit impacts more than one TOP in its RC Area. This ensures that the RC who has wide-area responsibility will identify such stability limits and prevent any gaps in identification and monitoring of stability limits that impacts more than one TOP in its RC Area. TOPs are still required to identify stability limits that are within its TOP area (including Generator Operator areas interconnected to its TOP area).

Requirement R5

Each Reliability Coordinator shall provide:

5.1. Each Planning Coordinator within its Reliability Coordinator Area, SOLs for its Reliability Coordinator Area (including the subset of SOLs that are IROLs) at least once every twelve calendar months.

5.2. Each impacted Planning Coordinator within its Reliability Coordinator Area,, the following information for each established stability limit and each established IROL at least once every twelve calendar months:

5.2.1. The value of the stability limit or IROL;

5.2.2. Identification of the Facilities that are critical to the derivation of the stability limit or IROL;

5.2.3. The associated IROL T_v for any IROL;

5.2.4. The associated Contingency(ies); and,

5.2.5. The type of limitation represented by the stability limit or IROL (e.g., voltage collapse, angular stability).

5.3. Each impacted Transmission Operator within its Reliability Coordinator Area, the value of the stability limits established pursuant to Requirement R4 and each IROL established pursuant to Requirement R1, in an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analysis, Real-time monitoring, and Real-time Assessments.

5.4. Each impacted Transmission Operator within its Reliability Coordinator Area, the information identified in Requirement R5 Parts 5.2.2 – 5.2.5 for each established stability limit or each IROL, and any updates to that information within an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses.

5.5. Each requesting Transmission Operator within its Reliability Coordinator Area, requested SOL information for its Reliability Coordinator Area, on a mutually agreed upon schedule.

Rationale R5

Requirement R5 requires the RC to provide SOLs (including the subset that are IROLs) and any updates to those SOLs to Planning Coordinators (PCs) and Transmission Operators (TOP)s. This is an improvement over Requirement R5 in FAC-014-2 because it provides additional clarity on when the RC is responsible for performing these tasks. FAC-014-2 Requirement R5 includes the triggering clause of when entities "provide a written request that includes a schedule for delivery of those limits", while Requirement R5 of FAC-014-3 clearly identifies the RC's responsibilities with or without a request. This also removes confusion associated with FAC-010 in terms of SOLs existing in the planning horizon. All requirements in pertaining to SOLs in the planning horizon have thus been removed.

The requirement addresses varying needs in terms of both the content and the frequency at which the information is provided. This requirement also complements existing NERC requirements that provide a construct for communication of SOLs and SOL-related information (e.g. TOP-003-3, IRO-010-2, IRO-014-3) to prevent redundancies in requirements. TOP-to-TOP SOL information communication is addressed in TOP-003-3. RC-to-RC SOL information communication is addressed

in IRO-014-3. TOP-to-RC information communication is addressed in Requirement R3 and may be addressed in IRO-010-2.

Requirement R5 Part 5.1 requires the RC to provide the PCs in its RC Area all SOLs and relevant SOL information at least once every 12 calendar months. This provides the PC the relevant information necessary for its assessments and its Transmission Planner's (TP's) assessments. MOD-032-1 and FAC-015-1 requirements provides the mechanism for SOLs to be communicated between the PCs and its TPs. It is expected that PCs do not need more frequent updates as most of their assessments are performed on an annual cycle. Transmission Service Providers were not retained as an entity that would have a reliability related need for stability limit and IROL related information. Nothing prohibits an RC from sharing such information outside of a NERC Reliability Standard for other non-reliability related purposes.

Requirement R5 Part 5.2 requires the RC to provide the impacted PCs additional specific information (consistent with FAC-014-2 R5.1.1 - R5.1.4) for stability limits and IROLs at least once every 12 calendar months. It is expected that PCs do not need more frequent updates as most of their assessments (and their respective TPs assessments) are performed on an annual cycle.

Requirement R5 Part 5.3 requires the RC to provide the impacted TOPs within its RC Area the value of the stability limits established in Requirement R4 and IROLs established in Requirement R1 in the Real-time Operations time horizon. This recognizes that the actual numerical "limit" (whether a new limit or modification of an existing one) may change based on varying system topology and thus those limit values must be provided in a timeframe designed to meet the impacted TOP's needs for their OPA, Real-time monitoring, and RTA.

Requirement R5 Part 5.4 requires the RC to provide the impacted TOPs additional specific information (consistent with FAC-014-2 R5.1.1-5.1.4) for stability limits and IROLs within Same-day or Operations Planning time horizon. This additional information is essential for the TOP's OPA; however, it can be communicated within a longer-term agreed upon time frame outside the Real-time Operations time horizon.

Additionally, Requirement R5 Part 5.5 requires that if a TOP requests any SOL information beyond what impacts that TOP, the RC must provide this SOL information as well. Both Requirement R5 Parts 5.4 and 5.5 require that the related information be provided in a mutually agreed upon schedule to ensure the TOP's needs are met (e.g. OPA, RTA, etc.) and the RC's ability to meet those needs are taken into consideration.

Requirement R6

Each Reliability Coordinator that is impacted by an IROL shall provide Transmission Owners and Generation Owners within its Reliability Coordinator Area a list of Facilities owned by that entity that are critical to the derivation of the IROL.

Rationale R6

Requirement R6 addresses FERC Order No. 777 directive for the communication of IROL information to Transmission Owners (TOs) (P6 and P41). FERC Order No. 777 states:

> *"As discussed below, we also direct NERC to develop a means to assure that IROLs are communicated to transmission owners." (P 6) "NERC should establish a clearly defined communication structure to assure that IROLs and changes to IROL status are timely communicated to transmission owners...One way to achieve this objective...is to modify FAC-014 to require the provision of IROLs to transmission owners. However, we leave it to NERC to determine the most appropriate means for communicating IROL status to transmission owners." (P 41)*

Requirement R5 Parts 5.2.1 through 5.2.5 requires that IROL information – including the Facilities critical to the derivation of the IROL – be communicated to the TOPs. SDT determined that while TOs and Generator Owners (GOs) need to be made aware of their Facilities that are critical to the derivation of the IROL, the TOs and GOs do not need to know the other IROL information specified in Requirement R5 Part 5.2.1 and Parts 5.2.3 through 5.2.5. These items may contain operationally sensitive information that should be limited to the TOPs that operate the equipment. Therefore, the SDT separated the communication to the TOs and GOs into a stand-alone Requirement R6.

The language "Each Reliability Coordinator that is impacted by an IROL" was used to cover scenarios where an IROL in one Reliability Coordinator Area contains Facilities that reside in a neighboring Reliability Coordinator's Area that are critical to the derivation of the IROL. Therefore, any Facilities that are critical to the derivation of an IROL will be communicated from the responsible RC to the appropriate TOs and GOs.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Mapping Document for FAC-014-2

Project 2015-09 Establish and Communicate System Operating Limits

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
FAC-014-2, Requirement R1 R1. The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with its SOL Methodology.	Requirements R1, R2, and R4 of FAC-014-3 R1. Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit Methodology (SOL Methodology). R2. Each Transmission Operator shall establish System Operating Limits (SOLs) for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL Methodology. R4. Each Reliability Coordinator shall establish stability limits to be used in operations when the limit impacts more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL Methodology.	Requirements R1, R2, and R4 of FAC-014-3 ensure that SOLs are established in accordance with the Reliability Coordinator's (RC's) SOL Methodology. Requirement R1 was changed to address an issue with the existing language in FAC-014-2, Requirement R1. With the original language, the RC is responsible for ensuring that SOLs established by the Transmission Operator (TOP) per FAC-014-2, Requirement R2 are consistent with the RC's SOL Methodology. This creates a situation where the RC is responsible for "ensuring" the actions of the TOP. Accordingly, if the TOP does not establish SOLs per its RC's SOL Methodology, then 1) the TOP is in violation of Requirement R2, and 2) the RC by default is in violation of Requirement R1 because the RC did

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		not ensure that the TOP's SOL was consistent with its SOL Methodology. The proposed revision addresses this issue and clarifies the appropriate responsibilities of the respective functional entities. 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. FAC-011-4 requirement R4 further addresses the RC responsibilities (beyond IROL establishment) for stability limit establishment where more than one TOP is impacted.
FAC-014-2, Requirement R2 R2. The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability	FAC-014-3, Requirement R2 R2. Each Transmission Operator shall establish System Operating Limits (SOLs) for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL Methodology.	The language from the existing FAC-014-2, Requirement R2 that states the TOP, "(as directed by its Reliability Coordinator)" was removed because it causes confusion and may be incorrectly understood to mean that the TOPs are

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology.		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 that these SOLs must be established in accordance with the RC's SOL Methodology.
FAC-014-2, Requirements R3 and R4 R3. The Planning Authority shall establish SOLs, including IROLs, for its Planning Authority Area that are consistent with its SOL Methodology. R4. The Transmission Planner shall establish SOLs, including IROLs, for its Transmission Planning Area that are consistent with its Planning Authority's SOL Methodology.	1. FAC-011-4, Requirement R8, Part 8.2 2. FAC-015-1, Requirements R 1 – R6 FAC-011-4, Requirement R8, Part 8.2: R8. Each Reliability Coordinator shall provide its new or revised SOL Methodology to: 8.2. Each Planning Coordinator and Transmission Planner responsible for planning any portion of the Reliability Coordinator Area prior to the effective date of the SOL Methodology;	The PCs and TOPs responsible for planning any portion of the RC's Area are made aware of the RC's SOL Methodology through FAC-011-4, Requirement R8, Part 8.2. By having the RC's SOL Methodology, PCs and TPs who plan any portion of the System in the RC Area have knowledge of the methods and criteria for establishing SOLs, including the stability performance criteria used for establishing stability limits in the operations horizon. New Reliability Standard FAC-015-1 along with the changes made to FAC-011-4 and FAC-014-3 represent an improvement for

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	FAC-015-1: R1. Each Planning Coordinator, when developing its steady-state modeling data requirements, shall implement a process to ensure that Facility Ratings used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than those established in accordance with its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator. R2. Each Planning Coordinator shall implement a process to ensure that System steady state voltage limits used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its	planning and operations to better work together to address the reliability issues that are ultimately faced in Real-time operations. FAC-015-1, Requirements R1 – R3 ensures that Planning Assessments performed for the Near-Term Transmission Planning Horizon (required by TPL-001-4), are bounded by modeling data and performance criteria that are equally limiting or more limiting than those established in accordance with the RC's SOL Methodology. FAC-015-1, Requirement R1 addresses Facility Ratings used in Planning Assessments, Requirement R2 addresses the System steady state voltage limits used in Planning Assessments, and Requirement R3 addresses the stability performance criteria used in Planning Assessments. These requirements address the three components of SOLs used in operations and facilitates continuity between operations and planning.

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	Reliability Coordinator's SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator. R3. Each Planning Coordinator shall implement a process to ensure the stability performance criteria used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the stability performance criteria established in its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting stability performance criteria than the stability performance criteria specified in its Reliability Coordinator's SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator. R4. Each Planning Coordinator shall provide the Facility Ratings, System steady-state voltage limits, and stability performance criteria for use in its Planning Assessment to its Transmission Planners and to requesting Planning Coordinators. R5. Each Transmission Planner shall use Facility Ratings, System steady-state voltage limits, and stability performance criteria in its Planning Assessment that are equally limiting or more	Implementing the processes required in FAC-015-1, Requirements R1 – R3 provides the PC with Facility Ratings, System steady-state voltage limits, and stability performance criteria that are equally limiting or more limiting than those established in accordance with the RC's SOL Methodology. FAC-015-1, Requirement R4 requires the PC to provide those Facility Ratings, System steady-state voltage limits, and stability performance criteria for use in its Planning Assessment to its TPs and to requesting PCs. FAC-015-1, Requirement R5 requires the TP to use the Facility Ratings, System steady-state voltage limits, and stability performance criteria in its Planning Assessment that are equally limiting or more limiting than the Facility Ratings, System steady-state voltage limits, and stability criteria provided by its PC. By implementing Requirements R1 – R5 of FAC-015-1, equally limiting or more limiting Facility Ratings, System steady-

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	limiting than the Facility Ratings, System steady-state voltage limits, and stability criteria provided by its Planning Coordinator. R6. Each Planning Coordinator shall communicate any instability, Cascading or uncontrolled separation identified in either its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment to each impacted Reliability Coordinator and Transmission Operator. This communication shall include: 6.1 The type of instability identified (e.g., voltage collapse, angular instability, transient voltage dip criteria violation); 6.2 The associated stability criteria used as part of determining the instability; 6.3 The associated Contingency(ies) which result(s) in the instability, Cascading or uncontrolled separation; 6.4 Any Remedial Action Scheme action, under voltage load shedding (UVLS) action, under frequency load shedding (UFLS) action, interruption of Firm Transmission Service, or Non-	state voltage limits and stability criteria that are established in accordance with the RC's SOL Methodology are ultimately implemented in the Planning Assessments performed by the PCs and TPs, thus improving reliability by ensuring continuity between planning and operations. FAC-015-1, Requirement R6 requires the PC to communicate any instability, Cascading or uncontrolled separation identified in the Planning Assessments to the RC and to impacted TOPs. The subparts of Requirement R6 require the communication of key information that can be useful to the RC and TOP to establish stability limits and IROLs that will ultimately be used in real-time operations.

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	Consequential Load Loss required to address the instability, Cascading or uncontrolled separation; 6.5 Any Corrective Action Plan associated with the instability, Cascading or uncontrolled separation.	
<u>FAC-014-2, Requirement R5, R5.1</u> R5. The Reliability Coordinator, Planning Authority and Transmission Planner shall each provide its SOLs and IROLs to those entities that have a reliability-related need for those limits and provide a written request that includes a schedule for delivery of those limits as follows: R5.1. The Reliability Coordinator shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and Planning Authorities within its Reliability Coordinator Area. For each IROL, the Reliability Coordinator shall provide the following supporting information:	The communication of SOL and IROL information from the Reliability Coordinator is addressed by: 1. FAC-014-3, Requirement R5 (addresses communication from the Reliability Coordinator to other entities) 2. IRO-014-3, Requirement R1 (addresses communication between Reliability Coordinators to support reliable operations) <u>FAC-014-3, Requirement R5:</u> R5. Each Reliability Coordinator shall provide: 5.1. Each Planning Coordinator within its Reliability Coordinator Area, SOLs for its Reliability Coordinator Area (including the subset of SOLs that are IROLs) at least once every twelve calendar months. 5.2. Each impacted Planning Coordinator within its Reliability Coordinator Area, the following	Reference the description above for Requirement R3 which describes a different set of roles and responsibilities for the PC and TP as defined in FAC-015-1. While the existing requirements in FAC-014-2, Requirement R5 are preserved in FAC-014-3, Requirement R5, FAC-014-3, Requirement R5 more specifically address the communications requirements for the RC. Each recipient of the RC communications is addressed in a separate subpart because each recipient has a slightly different need. This approach represents an improvement over the former approach. IRO-014-3, Requirement R1 and subparts addresses RC communication of critical operational information to adjacent RCs,

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
R5.1.1. Identification and status of the associated Facility (or group of Facilities) that is (are) critical to the derivation of the IROL. R5.1.2. The value of the IROL and its associated Tv. R5.1.3. The associated Contingency(ies). R5.1.4. The type of limitation represented by the IROL (e.g., voltage collapse, angular stability).	information for each established stability limit and each established IROL at least once every twelve calendar months: 5.2.1. The value of the stability limit or IROL; 5.2.2. Identification of the Facilities that are critical to the derivation of the stability limit or IROL; 5.2.3. The associated IROL Tv for any IROL; 5.2.4. The associated Contingency(ies); and 5.2.5. The type of limitation represented by the stability limit or IROL (e.g., voltage collapse, angular stability). 5.3. Each impacted Transmission Operator within its Reliability Coordinator Area, the value of the stability limits established pursuant to Requirement R4 and each IROL established pursuant to Requirement R1, in an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. 5.4. Each impacted Transmission Operator within its Reliability Coordinator Area, the	which addresses RC-to-RC communication and coordinated operations issues.

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	information identified in Requirement R5 Parts 5.2.2 – 5.2.5 for each established stability limit or each IROL, and any updates to that information within an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses. 5.5. Each requesting Transmission Operator within its Reliability Coordinator Area, requested SOL information for its Reliability Coordinator Area, on a mutually agreed upon schedule. <u>IRO-014-3, Requirement R1</u> R1. Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following: 1.1. Criteria and processes for notifications. 1.2. Energy and capacity shortages.	

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	1.3. Control of voltage, including the coordination of reactive resources. 1.4. Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments. 1.5. Provisions for periodic communications to support reliable operations.	
FAC-014-2, Requirement R5, R5.2 R5.2 The Transmission Operator shall provide any SOLs it developed to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area.	1. FAC-014-3, Requirement R3 2. MOD-028-2, Requirement R7 3. MOD-029-2a, Requirement R4 4. MOD-030-3, Requirement R2.6 FAC-014-3, Requirement R3 R3. The Transmission Operator shall provide its SOLs to its Reliability Coordinator in accordance with its Reliability Coordinator's SOL Methodology. MOD-028-2, Requirement R7: R7. The Transmission Operator shall provide the Transmission Service Provider of that ATC Path with the most current value for TTC for that ATC Path no more than:	The communication of SOLs from the TOP to its RC is preserved in FAC-014-3, Requirement R3. The revised language represents an improvement on the current standard because the specifics of TOP communication to the RC is now addressed in the RC's SOL Methodology. This revised requirement has a companion Requirement R7 in FAC-011-4 which states: R7. Each Reliability Coordinator shall include in its SOL Methodology the method and periodicity for Transmission Operators to communicate SOLs it established to its RC(s).

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	R7.1. One calendar day after its determination for TTCs used in hourly and daily ATC calculations. R7.2. Seven calendar days after its determination for TTCs used in monthly ATC calculations. MOD-029-2a, Requirement R4: R4. Within seven calendar days of the finalization of the study report, the Transmission Operator shall make available to the Transmission Service Provider of the ATC Path, the most current value for TTC and the TTC study report documenting the assumptions used and steps taken in determining the current value for TTC for that ATC Path. MOD-030-3, Requirement R2.6: [The TOP shall…] R2.6. Provide the Transmission Service Provider with the TFCs within seven calendar days of their establishment.	The Transmission Service Provider (TSP) was removed from the SOL communication chain because the TSP does not need SOLs to perform its obligations specified in the Modeling, Data, and Analysis (MOD) standards; rather, they need Total Transfer Capability (TTC) and Total Flowgate Capability (TFC) from the TOPs as required in Requirement R7 of MOD-028-2, Requirement R4 of MOD-029-2a, and Requirement R2.6 of MOD-030-3. The TTCs and TFCs provided to the TSPs already reflect the impact of any SOLs.
FAC-014-2, Requirement R5, R5.3 and R5.4 R5.3 The Planning Authority shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Planning Authorities, and to Transmission Planners, Transmission Service Providers, Transmission Operators	1. FAC-015-1, Requirements R1 – R6 2. MOD-028-2, Requirement R7 3. MOD-029-2a, Requirement R4 4. MOD-030-3, Requirement R2 5. TPL-001-4, Requirement R8 FAC-015-1, Requirements R1 –R6:	Reference the description above for Requirement R3 which describes a different set of roles and responsibilities for the PC and TP as defined in FAC-015-1. Implementing the processes required in FAC-015-1, Requirements R1 – R3

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
and Reliability Coordinators that work within its Planning Authority Area. R5.4 The Transmission Planner shall provide its SOLs (including the subset of SOLs that are IROLs) to its Planning Authority, Reliability Coordinators, Transmission Operators, and Transmission Service Providers that work within its Transmission Planning Area and to adjacent Transmission Planners.	R1. Each Planning Coordinator, when developing its steady-state modeling data requirements, shall implement a process to ensure that Facility Ratings used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than those established in accordance with its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator. R2. Each Planning Coordinator shall implement a process to ensure that System steady state voltage limits used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology, the	provides the PC with Facility Ratings, System steady-state voltage limits, and stability performance criteria that are equally limiting or more limiting than those established in accordance with the RC's SOL Methodology. FAC-015-1, Requirement R4 addresses the PC's role for providing the Facility Ratings, System steady-state voltage limits and stability performance criteria derived from Requirements R1 – R3 to the TPs and to requesting PCs for their use in performing Planning Assessments. FAC-015-1, Requirement R5 requires the TP to use the Facility Ratings, System steady-state voltage limits, and stability performance criteria in its Planning Assessment that are equally limiting or more limiting than the Facility Ratings, System steady-state voltage limits, and stability criteria provided by its PC. FAC-015-1, Requirements R1 – R5 result in PC and TPs using Facility Ratings, System steady state voltage limits, and stability performance criteria in their

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	Planning Coordinator shall provide a technical justification to its Reliability Coordinator. R3. Each Planning Coordinator shall implement a process to ensure the stability performance criteria used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the stability performance criteria established in its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting stability performance criteria than the stability performance criteria specified in its Reliability Coordinator's SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator. R4. Each Planning Coordinator shall provide the Facility Ratings, System steady-state voltage limits, and stability performance criteria for use in its Planning Assessment to its Transmission Planners and to requesting Planning Coordinators. R5. Each Transmission Planner shall use Facility Ratings, System steady-state voltage limits, and stability performance criteria in its Planning Assessment that are equally limiting or more limiting than the Facility Ratings, System steady-	Planning Assessments that are equally limiting or more limiting than the Facility Ratings, System Voltage Limits, and stability performance criteria established in accordance with the RC's SOL Methodology. FAC-015-1, Requirement R6 requires the PC to communicate any instability, Cascading or uncontrolled separation identified in the Planning Assessments to the RC and to impacted TOPs. The subparts of Requirement R6 require the communication of key information that can be useful to the RC and TOP to establish stability limits and IROLs that will ultimately be used in real-time operations. The TSP was removed from the SOL communication chain. The TSP does not need SOLs from the PCs or TPs; rather, TSPs need TTC and TFC from the TOPs as required in Requirement R7 of MOD-028-2, Requirement R4 of MOD-029-2a, and Requirement R2.6 of MOD-030-3. The

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	state voltage limits, and stability criteria provided by its Planning Coordinator. R6. Each Planning Coordinator shall communicate any instability, Cascading or uncontrolled separation identified in either its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment to each impacted Reliability Coordinator and Transmission Operator. This communication shall include: 6.1 The type of instability identified (e.g., voltage collapse, angular instability, transient voltage dip criteria violation); 6.2 The associated stability criteria used as part of determining the instability; 6.3 The associated Contingency(ies) which result(s) in the instability, Cascading or uncontrolled separation; 6.4 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 required to address the instability, Cascading or uncontrolled separation;	TTCs and TFCs provided to the TSPs already reflect the impact of any SOLs. TPL-001-4, Requirement R8 requires each PC and TP to distribute its Planning Assessment results to adjacent PCs and adjacent TPs 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. With this requirement, any functional entity with a reliability-related need for a PC's or TP's Planning Assessment can obtain that Planning Assessment. Requesting entities are then made aware of any system performance issues identified by these Planning Assessments.

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	6.5 Any Corrective Action Plan associated with the instability, Cascading or uncontrolled separation. MOD-028-2, Requirement R7: R7. The Transmission Operator shall provide the Transmission Service Provider of that ATC Path with the most current value for TTC for that ATC Path no more than: R7.1. One calendar day after its determination for TTCs used in hourly and daily ATC calculations. R7.2. Seven calendar days after its determination for TTCs used in monthly ATC calculations. MOD-029-2a, Requirement R4: R4. Within seven calendar days of the finalization of the study report, the Transmission Operator shall make available to the Transmission Service Provider of the ATC Path, the most current value for TTC and the TTC study report documenting the assumptions used and steps taken in determining the current value for TTC for that ATC Path.	

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	MOD-030-3, Requirement R2.6: [The TOP shall…] R2.6. Provide the Transmission Service Provider with the TFCs within seven calendar days of their establishment. TPL-001-4, Requirement R8: 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. 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.	
FAC-014-2, Requirement R6 R6. The Planning Authority shall identify the subset of multiple contingencies (if any),	FAC-015-1, Requirement R6 R6. Each Planning Coordinator shall communicate any instability, Cascading or	FAC-015-1, Requirement R6 cover the content of FAC-014-2, Requirement R6 and improves upon it as follows:

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
from Reliability Standard TPL-003 which result in stability limits. R6.1 The Planning Authority shall provide this list of multiple contingencies and the associated stability limits to the Reliability Coordinators that monitor the facilities associated with these contingencies and limits. R6.2 If the Planning Authority does not identify any stability-related multiple contingencies, the Planning Authority shall so notify the Reliability Coordinator.	uncontrolled separation identified in either its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment to each affected Reliability Coordinator and Transmission Operator. This communication shall include: 6.1 The type of the instability identified (e.g., voltage collapse, angular instability, transient voltage dip criteria violation); 6.2 The associated stability criteria used as part of determining the instability; 6.3 The associated Contingency(ies) which result(s) in the instability, Cascading or uncontrolled separation; 6.4 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 required to address the instability, Cascading or uncontrolled separation; 6.5 Any Corrective Action Plan associated with the instability, Cascading or uncontrolled separation.	• FAC-015-1, Requirement R6 addresses not only the identification of multiple contingencies that result in stability limits, but also address the key information RCs need to establish stability limits and IROLs used in operations. Unlike FAC-014-2, Requirement R6, FAC-015-1, Requirement R6 ensures the type of instability, relevant stability criteria, and mitigation assumptions used by the PC are communicated to the appropriate RC. • Additionally, FAC-015-1, Requirement R6 includes all planning events (single and multiple contingencies) that result in instability, Cascading, or uncontrolled separation. • FAC-014-2, Requirement R6, R6.2 is addressed by FAC-015-1, Requirement R6 because all instances of instability identified by the PC are to be communicated

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		to the RC in accordance with FAC-015-1, Requirement R6. In addition, FAC-014-2, Requirement R6, R6.2 is administrative in nature, given that the existing FAC-014-2, Requirement R6, R6.1 and proposed FAC-015-1, Requirement R6 both require communication of a defined set of stability related data. The absence of any communication of stability related data inherently implies the PC has not identified any instability and therefore has nothing to communicate.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Violation Risk Factor and Violation Severity Level Justifications

FAC-014-3 Establish and Communicate System Operating Limits

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Reliability Standard FAC-014-3 Establish and Communicate System Operating Limits (SOLs). 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 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 FAC-014-3 Requirement R1	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of high for this requirement is consistent with approved Reliability Standard TPL-001-4 which requires development of operating conditions through the use of system models.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failing to correctly identify an IROL could directly cause or contribute to Bulk Electric System (BES) instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-014-3, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator did not establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit Methodology (“SOL Methodology”) as established in FAC-011-4.

VSL Justifications for FAC-014-3, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-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 requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
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.

VRF Justifications for FAC-014-3 Requirement R2	
Proposed VRF	**Medium**

This reliability objective of Requirement R2 from approved Reliability Standard FAC-014-2 is now Requirement R2 of proposed Reliability Standard FAC-014-3. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-014-3, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Transmission Operator did not establish SOLs for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL Methodology.

VSL Justifications for FAC-014-3, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-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 requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
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.

VRF Justifications for FAC-014-3 Requirement R3	
Proposed VRF	**Medium**

This reliability objective of Requirement R5, R5.2 from approved Reliability Standard FAC-014-2 is now Requirement R3 of proposed Reliability Standard FAC-014-3. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-014-3, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Transmission Operator provided its SOLs to its Reliability Coordinator, but did not provide its SOLs at the periodicity at which the RC needs such information to perform its reliability functions.	The Transmission Operator did not provide its SOLs to its Reliability Coordinator.

VSL Justifications for FAC-014-3, Requirement R3	
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 R5, R5.2 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering 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 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.

VRF Justifications for FAC-014-3 Requirement R4	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of high for this requirement is consistent with approved Reliability Standard TPL-001-4 which requires development of operating conditions through the use of system models.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The establishment of incorrect stability limits could directly cause or contribute to BES instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-014-3, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator did not determine stability limits to be used in operations when the limit impacts more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL Methodology.

VSL Justifications for FAC-014-3, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-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 requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
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.

VRF Justifications for FAC-014-3 Requirement R5	
Proposed VRF	**High**

This reliability objective of Requirement R5 and Requirement R5, R5.1 from approved Reliability Standard FAC-014-2 is now Requirement R5 of proposed Reliability Standard FAC-014-3. Therefore, the existing VRF of high was maintained for consistency.

VSLs for FAC-014-3, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator did not provide one of the items listed in Requirement R5 Parts 5.1 through 5.5.	The Reliability Coordinator did not provide two of the items listed in Requirement R5 Parts 5.1 through 5.5.	The Reliability Coordinator did not provide three of the items listed in Requirement R5 Parts 5.1 through 5.5.	The Reliability Coordinator did not provide four or more of the items listed in Parts 5.1 through 5.5.

VSL Justifications for FAC-014-3, Requirement R5	
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 R5, sub-requirement R5.1. Therefore, the proposed VSLs do not have the unintended consequence of lowering 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 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.

VRF Justifications for FAC-014-3 Requirement R6	
Proposed VRF	**High**

This reliability objective of Requirement R5, R5.1 from approved Reliability Standard FAC-014-2 is now Requirement R6 of proposed Reliability Standard FAC-014-3. Therefore, the existing VRF of high was maintained for consistency.

VSLs for FAC-014-3, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator with an established IROL, or the Reliability Coordinator impacted by a neighboring Reliability Coordinator IROL, did not provide Transmission Owners or Generation Owners within its Reliability Coordinator Area a list of Facilities owned by that entity that are critical to the derivation of the IROL.

VSL Justifications for FAC-014-3, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-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 requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
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.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the Board of Trustees.

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15

Anticipated Actions	Date
45-day formal comment period with ballot	September 2017 – November 2017
45-day formal comment period with additional ballot	January 2018 – February 2018
10-day final ballot	February 2018
NERC Board adoption	May 2018

A. Introduction

1. **Title:** Coordination of Planning Assessments with the Reliability Coordinator's SOL Methodology

2. **Number:** FAC-015-1

3. **Purpose:** To ensure the Facility Ratings, System steady-state voltage limits, and stability criteria used in Planning Assessments are coordinated with the Reliability Coordinator's System Operating Limits (SOL) Methodology.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Planning Coordinator

   4.1.2. Transmission Planner

5. **Effective Date:** See Implementation Plan for Project 2015-09.

B. Requirements and Measures

R1. Each Planning Coordinator, when developing its steady-state modeling data requirements, shall implement a process to ensure that Facility Ratings used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than those established in accordance with its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator implemented its process in accordance with Requirement R1.

R2. Each Planning Coordinator shall implement a process to ensure that System steady state voltage limits used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator implemented its process in accordance with Requirement R2.

R3. Each Planning Coordinator shall implement a process to ensure the stability performance criteria used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the stability performance criteria established in its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting stability performance criteria than the stability performance criteria specified in its Reliability Coordinator's SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M3. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator implemented its process in accordance with Requirement R3.

R4. Each Planning Coordinator shall provide the Facility Ratings, System steady-state voltage limits, and stability performance criteria for use in its Planning Assessment to its Transmission Planners and to requesting Planning Coordinator's. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator provided its information in accordance with Requirement R4.

R5. Each Transmission Planner shall use Facility Ratings, System steady-state voltage limits, and stability performance criteria in its Planning Assessment that are equally limiting or more limiting than the Facility Ratings, System steady-state voltage limits, and stability criteria provided by its Planning Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M5. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Transmission Planner used the information provided by its Planning Coordinator in accordance with Requirement R5.

R6. Each Planning Coordinator shall communicate any instability, Cascading or uncontrolled separation identified in either its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment to each impacted Reliability Coordinator and Transmission Operator. This communication shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- **6.1** The type of instability identified (e.g., voltage collapse, angular instability, transient voltage dip criteria violation);
- **6.2** The associated stability criteria used as part of determining the instability;
- **6.3** The associated Contingency(ies) which result(s) in the instability, Cascading or uncontrolled separation;
- **6.4** Any Remedial Action Scheme action, undervoltage load shedding (UVLS) action, underfrequency load shedding (UFLS) action, interruption of Firm Transmission

Service, or Non-Consequential Load Loss required to address the instability, Cascading or uncontrolled separation; and

6.5 Any Corrective Action Plan associated with the instability, Cascading or uncontrolled separation.

M6. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator communicated the information in accordance with Requirement R6.

C. Compliance

1. Compliance Monitoring Process

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

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

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

- The Planning Coordinator and Transmission Planner shall keep evidence for Requirements R1 through R6 for the most current year plus the previous three years.

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

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	The Planning Coordinator used less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology, but did not provide its documented technical justification to its Reliability Coordinator.	The Planning Coordinator used less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology, but did not document the technical justification.	The Planning Coordinator failed to implement a process to ensure that Facility Ratings used in Planning Assessment are equally limiting or more limiting than those established in its Reliability Coordinator's SOL Methodology.
R2.	N/A	The Planning Coordinator used less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology, but did not provide its documented technical justification to its Reliability Coordinator.	The Planning Coordinator used less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology, but did not document the technical justification.	The Planning Coordinator failed to implement a process to ensure that System steady-state voltage limits used in Planning Assessments are equally limiting or more limiting than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology.
R3.	N/A	The Planning Coordinator used less limiting stability	The Planning Coordinator used less limiting stability	The Planning Coordinator failed to implement a

		performance criteria than the stability performance criteria established in its Reliability Coordinator's SOL Methodology, but did not provide its documented technical justification to its Reliability Coordinator.	performance criteria than the stability performance criteria established in its Reliability Coordinator's SOL Methodology, but did not document the technical justification.	process to ensure that stability performance criteria used in planning assessments are equally limiting or more limiting than those used in operations established in the Reliability Coordinator's SOL Methodology.
R4.	N/A	N/A	The Planning Coordinator failed to provide the Facility Ratings, System steady-state voltage limits, and stability performance criteria to all of its Transmission Planners. OR The Planning Coordinator failed to provide one element of the required information.	The Planning Coordinator failed to provide the Facility Ratings, System steady-state voltage limits, and stability performance criteria to all of its Transmission Planners. OR The Planning Coordinator failed to provide two or more elements of the required information.
R5.	N/A	N/A	N/A	The Transmission Planner failed to use Facility Ratings, System steady-stability voltage limits, and stability performance criteria that were equally or more limiting than those provided by its Planning Coordinator.

R6.	The Planning Coordinator communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain one of the elements listed in Requirement R6, Parts 6.1 – 6.5.	The Planning Coordinator communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain two of the elements listed in Requirement R6, Parts 6.1 – 6.5.	The Planning Coordinator communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain three elements listed in Requirement R6, Parts 6.1 – 6.5.	The Planning Coordinator communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain four or more of the elements listed in Requirement R6, Parts 6.1 – 6.5. OR The Planning Coordinator failed to communicate any identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator.

D. Regional Variances

None

E. Interpretations

None

F. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
1		Project 2015-09 SOL – Adopt new standard.	New

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Rationale for FAC-015-1

September 2017

Requirement R1

Each Planning Coordinator, when developing its steady-state modeling data requirements, shall implement a process to ensure that Facility Ratings used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than those established in accordance with its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator.

Rationale R1

Requirement R1 was drafted to ensure the appropriate use of applicable Facility Ratings in planning models. Analysis of these models determines System needs, potential future transmission expansion and other Corrective Action Plans for reliable System operations. Therefore, it is imperative that the System is planned in such a way to support the successful operation of facilities when they are placed in service.

Requirement R1 provides a mechanism for the coordination of Facility Ratings in planning models to those established in accordance with the Reliability Coordinator's (RC's) System Operating Limit (SOL) Methodology. Since the analysis of planning models determines what facilities are constructed or modified, Facility Ratings used in these analyses should be equally limiting or more limiting than those established in accordance with the RC's SOL Methodology. Otherwise, operators could be unduly limited by thermal constraints that were not identified in preceding planning studies.

Reliability Standard MOD-032 requires the modeling data in a Planning Coordinator (PC) area be coordinated between the PC and applicable Transmission Planners (TPs). It is the opinion of the standard drafting team (SDT) that the resulting coordination is the appropriate means to ensure Facility Ratings included in planning models are equally limiting or more limiting than the Facility Ratings established in accordance with the RC's SOL Methodology, since Planning Assessments and Corrective Action Plans are developed based on analysis of these models (TPL-001).

The Near-Term Planning Horizon is specified because planning assumptions tend to be more certain earlier in the Planning Horizon. Additionally, construction activities or other Corrective Action Plans are more likely to be finalized in this period.

The intent of Requirement R1 is not to change, limit, or modify Facility Ratings determined by the equipment owner per FAC-008. The intent is to utilize those owner-provided Facility Ratings such that the System is planned to support the reliable operation of that System. This is accomplished by requiring the PC to use Facility Ratings that are equally limiting or more limiting than those established in accordance with the RC's SOL Methodology. If less limiting Facility Ratings are used by the PC, a technical justification is required to be documented and provided to the RC. This does

not give the RC authority over the PC in the development of the Planning Assessment. It does, however, facilitate communication between planning and operating entities so that analysis of the System by these entities are coordinated.

Requirement R2

Each Planning Coordinator shall implement a process to ensure that System steady state voltage limits used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator.

Rationale R2

The purpose of TPL-001 is 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." Because the Planning Assessment (including the Corrective Action Plan) is the primary output of TPL-001, planning criteria used in developing the Planning Assessment should support the eventual operation of BES Facilities.

Requirement R2 was drafted to ensure the use of appropriate System steady-state voltage limits when performing studies in support of developing the Planning Assessment. These studies determine System needs, potential future transmission expansion and other Corrective Action Plans for reliable System operation. Therefore, it is imperative that the System is planned in such a way to support the successful operation of facilities when they are placed in service.

Since the analysis of planning models determines what Facilities are constructed or modified, the application of System steady-state voltage limits used in studies that support the development of the Planning Assessment should be equally limiting or more limiting than those established in accordance with the RC's SOL Methodology. Otherwise, operators could be unduly limited by voltage constraints that were not identified in preceding planning studies. Requirement R2 provides a mechanism for the coordination of System steady-state voltage limits evaluated in planning studies with the System Voltage Limits established in accordance with the RC's SOL Methodology.

The Near-Term Transmission Planning Horizon is specified because planning assumptions tend to be more certain earlier in the planning horizon. Additionally, construction activities or other Corrective Action Plans are more likely to be finalized in this period.
The intent of Requirement R2 is to supplement Requirement R5 of TPL-001-4 which states, "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." When determining the criteria for System steady-state voltage limits in accordance with TPL-001-4 Requirement R2, the PC is required to implement the process described in FAC-015-1 Requirement R2.

Requirement R2 requires the PC to use System steady-state voltage limits that are equally limiting or more limiting than the System Voltage Limits established in accordance with the RC's SOL methodology. If less limiting System steady-state voltage limits are used by the PC, a technical justification is required to be documented and provided to the RC. This does not give the RC authority over the PC in the development of the Planning Assessment. It does, however, facilitate communication between planning and operating entities so that analysis of the System by these entities are coordinated.

Requirement R3

Each Planning Coordinator shall implement a process to ensure the stability performance criteria used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the stability performance criteria established in its Reliability Coordinator's SOL methodology. If the Planning Coordinator uses less limiting stability performance criteria than the stability performance criteria specified in its Reliability Coordinator's SOL methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator.

Rationale R3

The purpose of TPL-001-4 is to "…develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probably Contingencies." Because the Planning Assessment (including the Corrective Action Plan) is the primary output of TPL-001-4, planning criteria used in developing the Planning Assessment should support the eventual operation of BES facilities.

Requirement R3 was drafted to ensure the use of appropriate stability performance criteria when performing studies in support of developing the Planning Assessment. These studies determine System needs, potential future transmission expansion and other Corrective Action Plans for reliable System operation. Therefore, it is imperative that the System is planned in such a way to support the successful operation of facilities when they are placed in service.

Since the analysis of planning models determines what facilities are constructed or modified, the application of stability performance criteria used in studies that support the development of the Planning Assessment should be equally limiting or more limiting than the criteria specified in the RCs SOL Methodology. Otherwise, operators could be unduly limited by stability constraints that were not identified in preceding planning studies. Requirement R3 provides a mechanism for the coordination of stability performance criteria evaluated in planning studies with the Reliability Coordinator's SOL Methodology.

The Near-Term Planning Horizon is specified because planning assumptions tend to be more certain earlier in the Planning Horizon. Additionally, construction activities or other Corrective Action Plans are more likely to be finalized in this period.

The intent of Requirement R3 is to address the stability performance criteria used by PCs and TPs when performing the required stability analysis per TPL-001. When the PC performs the relevant stability analyses in accordance with TPL-001, they are required to implement the process in FAC-015-1 Requirement R3, which requires the PC to use stability performance criteria that are equally limiting or more limiting than the criteria established in accordance with the RC's SOL Methodology. If less limiting stability performance criteria are used by the PC, a technical justification is required to be documented and provided to the RC. This does not give the RC authority over the PC in the development of the Planning Assessment. It does, however, facilitate communication between planning and operating entities so that analysis of the System by these entities are coordinated.

Requirement R4

Each Planning Coordinator shall provide the Facility Ratings, System steady-state voltage limits, and stability performance criteria for use in its Planning Assessment to its Transmission Planners and to requesting Planning Coordinators.

Requirement R5

Each Transmission Planner shall use Facility Ratings, System steady-state voltage limits, and stability performance criteria in its Planning Assessment that are equally limiting or more limiting than the Facility Ratings, System steady-state voltage limits, and stability criteria provided by its Planning Coordinator.

Rationale R4 and R5

Requirements R4 and R5 provide for the explicit coordination between PCs and TPs of Facility Ratings, System steady-state voltage limits, and stability performance criteria used to develop Planning Assessments of the PC area. Additionally, Requirement R4 provides a mechanism for other PCs to obtain this same information, as needed. Requirement R5 also allows the TP to use more conservative Facility Ratings, System steady-state voltage limits, and stability performance criteria than those the PC provides where the TP deems appropriate

These requirements supplement TPL-001-4 Requirements R1, R5, and R6 by ensuring Facility Ratings, System steady-state voltage limits, and stability performance criteria are consistently applied in Planning Assessments of the PC area.

Requirement R6

Each Planning Coordinator shall communicate any instability, Cascading or uncontrolled separation identified in either its Planning Assessment of the Near-Term Transmission Planning Horizon or its

Transfer Capability assessment to each impacted Reliability Coordinator and Transmission Operator. This communication shall include:

- **6.1** The type of instability identified (e.g., voltage collapse, angular instability, transient voltage dip criteria violation);
- **6.2** The associated stability criteria used as part of determining the instability;
- **6.3** The associated Contingency(ies) which result(s) in the instability, Cascading or uncontrolled separation;
- **6.4** 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 required to address the instability, Cascading or uncontrolled separation;
- **6.5** Any Corrective Action Plan associated with the instability, Cascading or uncontrolled separation.

Rationale R6

IRO-017-1 Requirement R3 requires PCs and TPs to provide their Planning Assessments to impacted RCs. However, Requirement R2 Part 2.4 and Requirement R4 in TPL-001-4, which outline the Stability analysis portion of the Planning Assessment, do not provide for the level of detail prescribed in FAC-015-1 Requirement R6. Therefore this requirement was drafted to ensure the appropriate details regarding potential instability identified in the Stability portion of the Planning Assessment for the Near-Term Transmission Planning Horizon are provided to impacted RC and Transmission Operators (TOPs).

The information itemized in Requirement R6 is a key consideration for RC and TOPs in the establishment of SOLs. Of particular importance is the identification of potential risks of instability, Cascading conditions and uncontrolled separation that warrant establishment of an IROL by the RC. The details required by Requirement R6 will supplement the severe System conditions identified Requirements R4 Parts 4.4 & 4.5 of TPL-001-4.

Violation Risk Factor and Violation Severity Level Justifications

FAC-015-1 System Coordination of Planning Assessments with the Reliability Coordinator's SOL Methodology

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Reliability Standard FAC-015-1 System Coordination of Planning Assessments with the Reliability Coordinator's System Operating Limits (SOL) Methodology. 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 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 FAC-015-1 Requirement R1	
Proposed VRF	**Medium**

This reliability objective of Requirement R3 from approved Reliability Standard FAC-014-2 is now Requirement R1 of proposed Reliability Standard FAC-015-1. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-015-1, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	The Planning Coordinator used less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology, but did not provide its documented technical justification to its Reliability Coordinator.	The Planning Coordinator used less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology, but did not document the technical justification.	The Planning Coordinator failed to implement a process to ensure that Facility Ratings used in Planning Assessment are equally limiting or more limiting than those established in its Reliability Coordinator's SOL Methodology.

VSL Justifications for FAC-015-1, Requirement R1	
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 R3 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering 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 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.

VRF Justifications for FAC-015-1 Requirement R2	
Proposed VRF	**Medium**

This reliability objective of Requirement R3 from approved Reliability Standard FAC-014-2 is now Requirement R2 of proposed Reliability Standard FAC-015-1. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-015-1, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
N/A	The Planning Coordinator used less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology, but did not provide its documented technical justification to its Reliability Coordinator.	The Planning Coordinator used less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology, but did not document the technical justification.	The Planning Coordinator failed to implement a process to ensure that System steady-state voltage limits used in Planning Assessments are equally limiting or more limiting than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology.

VSL Justifications for FAC-015-1, 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 R3 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering 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 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.

VRF Justifications for FAC-015-1 Requirement R3	
Proposed VRF	**Medium**

This reliability objective of Requirement R3 from approved Reliability Standard FAC-014-2 is now Requirement R3 of proposed Reliability Standard FAC-015-1. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-015-1, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
N/A	The Planning Coordinator used less limiting stability performance criteria than the stability performance criteria established in its Reliability Coordinator's SOL Methodology, but did not provide its documented technical justification to its Reliability Coordinator.	The Planning Coordinator used less limiting stability performance criteria than the stability performance criteria established in its Reliability Coordinator's SOL Methodology, but did not document the technical justification.	The Planning Coordinator failed to implement a process to ensure that stability performance criteria used in planning assessments are equally limiting or more limiting than those used in operations established in its Reliability Coordinator's SOL Methodology.

VSL Justifications for FAC-015-1, Requirement R3	
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 R3 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering 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 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.

VRF Justifications for FAC-015-1 Requirement R4	
Proposed VRF	**Medium**

This reliability objective of Requirement R5, R5.3 from approved Reliability Standard FAC-014-2 is now Requirement R4 of proposed Reliability Standard FAC-015-1. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-015-1, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Planning Coordinator failed to provide the Facility Ratings, System steady-state voltage limits, and stability performance criteria to all of its Transmission Planners. OR The Planning Coordinator failed to provide one element of the required information.	The Planning Coordinator failed to provide the Facility Ratings, System steady-state voltage limits, and stability performance criteria to all of its Transmission Planners. OR The Planning Coordinator failed to provide two or more elements of the required information.

VSL Justifications for FAC-015-1, Requirement R4	
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 R5, R5.3 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering 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 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.

VRF Justifications for FAC-015-1 Requirement R5	
Proposed VRF	**Medium**

This reliability objective of Requirement R4 from approved Reliability Standard FAC-014-2 is now Requirement R5 of proposed Reliability Standard FAC-015-1. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-015-1, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Transmission Planner failed to use Facility Ratings, System steady-stability voltage limits, and stability performance criteria that were equally or more limiting than those provided by its Planning Coordinator.

VSL Justifications for FAC-015-1, Requirement R5	
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 R4 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering 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 requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
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.

VRF Justifications for FAC-015-1 Requirement R6	
Proposed VRF	**Medium**

This reliability objective of Requirement R5, R5.3 and Requirement R6 from approved Reliability Standard FAC-014-2 is now Requirement R6 of proposed Reliability Standard FAC-015-1. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-015-1, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
The Planning Coordinator communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator but the communication did not contain one of the elements listed in Requirement R6, Parts 6.1 – 6.5.	The Planning Coordinator communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator but the communication did not contain two of the elements listed in Requirement R6, Parts 6.1 – 6.5.	The Planning Coordinator communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator but the communication did not contain three elements listed in Requirement R6, Parts 6.1 – 6.5.	The Planning Coordinator communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator but the communication did not contain four or more of the elements listed in Requirement R6, Parts 6.1 – 6.5. OR The Planning Coordinator failed to communicate any identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator.

VSL Justifications for FAC-015-1, Requirement R6	
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 R5, R5.3 and R6 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering 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 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.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2015-09 Establish and Communicate System Operating Limits

Applicable Standard(s)

- Definition of System Voltage Limit (SVL) in the Glossary of Terms Used in NERC Reliability Standards ("NERC Glossary")
- FAC-011-4 System Operating Limits Methodology for the Operations Horizon
- FAC-014-3 Establish and Communicate System Operating Limits
- FAC-015-1 Coordination of Planning Assessments with the Reliability Coordinator's SOL Methodology

Requested Retirement(s)

- FAC-010-3 System Operating Limits Methodology for the Planning Horizon
- FAC-011-3 System Operating Limits Methodology for the Operations Horizon
- FAC-014-2 Establish and Communicate System Operating Limits

[*New/Modified/Retired*] Terms in the NERC Glossary of Terms

Proposed New Definition(s):
System Voltage Limit: The maximum and minimum steady-state voltage limits (both normal and emergency) that provide for acceptable System performance.

Applicable Entities

- Reliability Coordinator
- Planning Coordinator
- Transmission Planner
- Transmission Operator

Effective Date

The effective date for proposed Reliability Standards FAC-011-4, FAC-014-3, and FAC-015-1 and the NERC Glossary term "System Voltage Limit" is provided below:

Where approval by an applicable governmental authority is required, Reliability Standards FAC-011-4, FAC-014-3, and FAC-015-1 and the NERC Glossary term "System Voltage Limit" shall become effective the first day of the first calendar quarter that is twelve (12) calendar months after the effective date of the applicable governmental authority's order approving the standards and term, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, Reliability Standards FAC-011-4, FAC-014-3, and FAC-015-1 and the NERC Glossary term "System Voltage Limit" shall become

effective on the first day of the first calendar quarter that is twelve (12) calendar months after the date the standards and term are adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

Currently-Effective NERC Reliability Standards

Reliability Standards FAC-010-3, FAC-011-3, and FAC-014-2 shall be retired immediately prior to the effective date of the proposed Reliability Standards FAC-011-4, FAC-014-3, and FAC-015-1.

Initial Performance of Periodic Requirements

FAC-014-3 Requirement R5, Parts 5.1 and 5.2

The initial performance of FAC-014-3, Requirement R5, Parts 5.1 and 5.2 must be within 12 calendar months of the effective date of FAC-014-3.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Rationales for FAC-010-3 (Retirement) and FAC-015-1

September 2017

Background

The Facilities Design, Connections, and Maintenance (FAC) group of Reliability Standards provide for, among other things, the important reliability objective of establishing and communicating System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs) that help ensure reliable operation of the Bulk Electric System (BES). Specifically, under currently-effective Reliability Standard FAC-010-3, each Planning Authority must have a documented methodology for establishing SOLs (including IROLs) used in the planning horizon. Currently-effective Reliability Standard FAC-011-3 requires each Reliability Coordinator (RC) to have a documented methodology for establishing SOLs (including IROLs) within its Reliability Coordinator Area for the operations horizon. Further, under currently-effective Reliability Standard FAC-014-2, Transmission Operators (TOPs) must establish and communicate SOLs consistent with the RC's methodology and RCs must determine and communicate which of those SOLs are deemed as IROLs. Likewise, FAC-014-2 requires Planning Coordinators (PCs) and Transmission Planners (TPs) to establish and communicate SOLs and IROLs used in the planning horizon consistent with the PC's SOL Methodology.

The FAC-010, FAC-011, and FAC-014 Reliability Standards, however, have remained essentially unchanged since they were initially developed and became effective in 2008. Since that time there have been many improvements to other mandatory NERC Reliability Standards that work in concert with those FAC Reliability Standards, namely, those in the Transmission Planning (TPL), Transmission Operations (TOP), and Interconnection Reliability Operations and Coordination (IRO) groups of Reliability Standards. Specifically, the retired versions TPL-001, 002, 003, and 004 Reliability standards have been replaced with currently-effective TPL-001-4, all of the TOP standards have been replaced with the currently-effective TOP-001-3, TOP-002-4, and TOP-003-3, and all of the IRO standards have been modified. The FAC Reliability Standards that address SOLs and IROLs are inextricably linked to many of these TPL, TOP, and IRO Reliability Standards, as they all address in some manner the foundational reliability concept of reliable system performance as it relates to SOLs and IROLs. While the changes to the TPL, TOP, and IRO standards have been significant and have evolved as industry practices and needs have changed, there have been no consequential substantive changes to the related FAC Reliability Standards. One of the primary objectives of Project 2015-09 is to make changes to the SOL/IROL-related FAC standards to create better alignment with the currently-effective TPL, TOP, and IRO Reliability Standards.

The Project 2015-09 standard drafting team (SDT) is proposing to make a significant improvement to the SOL/IROL-related FAC standards by minimizing redundancy, allowing for better continuity from the establishment to communication of SOLs, and improving the efficiency and effectiveness of the tasks performed by planners and operators to achieve the ultimate reliability objective of reliable system performance in operations. As discussed in this whitepaper, one of the fundamental changes proposed by

the SDT is to retire the FAC-010-3 Reliability Standard, eliminating the requirement for PCs to have a methodology for establishing SOLs for use in the planning horizon, as well as the corresponding requirements in the FAC-014 Reliability Standard related to the establishment and communication of planning horizon SOLs and IROLs. As discussed further below, the SDT concluded that, with the changes in TPL-001-4, the establishment of planning horizon SOLs were unnecessary and not useful for ensuring reliable planning or reliable operations. Rather, the SDT concluded, the reliability need was for the limits and criteria used in the TPL-001-4 Planning Assessments to be equally limiting or more limiting than those established in accordance with or identified within its RC's SOL Methodology. The SDT developed proposed FAC-015-1 to ensure the coordination of the limits and criteria used in the Planning Assessment with the RC's SOL Methodology.

Under the current construct, PCs and RCs may have significantly different SOL Methodologies as the currently-effective Reliability Standards (FAC-010-3, FAC-011-3 & FAC-014-2) do not have any link requiring coordination between the methodologies. Furthermore, the nature of the current construct does not address continuity between planning and operations and may potentially result in a system not adequately planned for operational needs. The SDT's proposed changes help address the potential for inconsistencies between the PC's SOL Methodology and the RC's SOL Methodology.

Additionally, because of the evolution of the TPL standards, there are many redundancies in the responsibilities for PCs and Transmission Planners (TPs) between those in FAC-010/FAC-014 and those in TPL-001-4. In fact, planners are under no obligation to use (and many do not use) the PC's SOL Methodology for their Planning Assessments. Under Reliability Standard TPL-001-4, the SOLs established for the planning horizon pursuant to the FAC-010 and FAC-014 Reliability Standards are not necessary for reliable planning.

The SDT's proposal addresses both of these issues by providing for better continuity between planning and operations and by eliminating any redundancies that exist. To accomplish these objectives, the SDT is proposing a new construct. Under the proposed construct, the terms "SOL" and "IROL" are only applicable to the operations horizon and, in turn, only the RC would have an obligation to develop an SOL Methodology. RCs and TOPs would continue to have the responsibility under the FAC-014 Reliability Standard for establishing SOLs and IROLs consistent with the RCs' SOL Methodology. Planners, however, would no longer have an obligation to have an SOL Methodology applicable for the planning horizon, nor would planners be required to establish SOLs and IROLs for use in the planning horizon. Instead, planners would continue to perform Planning Assessments in accordance with TPL-001-4, and work with operating entities per the proposed new standard FAC-015-1 to ensure continuity between planning and operations. Specifically, under proposed FAC-015-1, planners are responsible for ensuring that the Facility Ratings, System (steady-state) voltage limits, and stability performance criteria used in their planning assessments for the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the Facility Ratings, System Voltage Limits, and stability performance criteria as determined in accordance with the RC's SOL Methodology.

This whitepaper demonstrates that the proposed construct would improve reliability by eliminating redundancies and by providing better continuity between planning and operations. The primary principles of the proposed approach include:

- Clarifying that SOLs are established only for the *operations horizon,* which aligns with the *"Operating"* term in System *"Operating"* Limits. Additionally, IROLs are better identified by the RC in the operations time horizon.

- The existing FAC-010-3 and related requirements in FAC-014-2 are addressed by TPL-001-4 and proposed FAC-015-1such that the retirement of FAC-010 and related requirements in FAC-014-2 would not create any reliability gaps.

- The addition of FAC-015-1 consolidates PC and TP requirements related to coordination of limits and criteria utilized in the planning horizon with those used in the operations horizon into one standard. This reduces the risk of multiple varying methodologies/processes, clarifies the usage of such limits and criteria (TPL-001-4, FAC-010-3, FAC-013-2) and eliminates any redundancy with such limits and criteria.

- Clarity and efficiency of communication of limits and criteria between planning and operating entities is improved with FAC-015-1.

System Operating Limits in the Planning Horizon

There are two different time frames in which the system is analyzed to ensure reliable operation: the planning horizon and the operations horizon. The time frame covered by the PC's SOL methodology developed pursuant to FAC-010-3 is for the *planning horizon*. The planning horizon covers the period from one year and beyond, while the operations horizon covers real-time (now) to one year. Between those two time horizons, the topology of the system could be quite different based on the addition of new projects, changes in generation, planned or forced outages of elements, and different uses of the system (power transfers), and weather.

Under the currently-effective FAC Reliability Standards, planners must establish SOLs for use in the planning horizon and operators must establish SOLs for use in operations. The initial intent for requiring planners to establish SOLs for use in the planning horizon was to develop a consistent set of limits to be used by the TPs while *planning* for the reliability of the transmission system. To ensure this consistency, the PC develops the SOL Methodology to be used by its TPs and thus provide for an overall, coherent transmission plan for a PC area.

The purpose of requiring the establishment of SOLs for the operations horizon is to identify limits that if operated within, will result in the system being *operated* reliably. TOPs must establish SOLs in the operations horizon that account for real-time characteristics (generation, load, topology and transfers) of their system. To ensure the consistent use of limits within a RC area, the RC is obligated to develop the SOL methodology to be used by its TOPs. The RC's methodology includes how Facility Ratings, System Voltage Limits, and stability performance criteria will be used to establish limits for use in assessments that determine whether the system is being reliably *operated*. Additionally, the RC's methodology prescribes what tests (Contingencies) must be used during the reliability assessment of the system during operations.

One of the key aspects of the proposed new construct is to eliminate the use of the SOL term as applied to the planning horizon. The SDT views SOLs as limits that are used in operations, hence the use of the term

"Operating" in System "Operating" Limits. The components of SOLs include the use of Facility Ratings, System Voltage Limits, and stability limits. These SOLs are based on specifications and criteria identified in the RC's SOL Methodology. While planners also use Facility Ratings provided by Facility Owners, System steady state voltage limits (TPL-001-4 Requirement R5), and stability performance criteria (TPL-001-4 Requirement R6) for its Planning Assessments, these are not referred to as SOLs.

The SDT determined that there is limited value in requiring PCs and TPs to establish SOLs for use in the planning horizon. Rather, the SDT believes that the reliability objective is to ensure that there is continuity between the limits and criteria used in the Planning Assessments with the limits and criteria (i.e., SOLs) that are used in operations. This adds further clarity that it is the RCs and TOPs – not the PCs and TPs – who determine the SOLs and IROLs that are used in operations. However, the RCs and TOPs may use the information provided by PCs and TPs, especially with regard to risks for System instability, Cascading, and uncontrolled separation, when developing the SOLs and IROLs used in operations. Proposed FAC-015-1 Requirement R6 retains this concept, which is currently in FAC-014-2 Requirement R6, and appropriately points to the TPL-001-4 Reliability Standard rather than FAC-010.

Another key difference in the proposed new construct is seen in the PC's and TP's role in addressing instability and the establishment of IROLs. Under the current construct, PCs and TPs are responsible for identifying stability SOLs and IROLs in accordance with the PCs Methodology. As stated above, there is little value in the establishment of SOLs and IROLs (by current definitions a "value" such as MW, Mvar, etc.) for use in the planning horizon; however, there is great value identifying more severe System risks in the planning horizon and communicating those risks to the impacted entities who operate those systems. PCs and TPs are currently responsible for identifying more severe System impacts such as Cascading, voltage instability, or uncontrolled islanding in accordance with TPL-001-4 Requirements R3.4, R3.5, R4.4, and R4.5. The new FAC-015-1 requires continuity in the criteria used and requires that the PC and TP communicate these risks of System instability, Cascading or uncontrolled separation identified in its Planning Assessment to impacted RCs and impacted TOPs. The entities that operate those systems can then use that information, if applicable and appropriate, to assist in establishing stability limits and IROLs that will ultimately be used in operations.

SOLs in the planning horizon are developed starting with a model that has all facilities in service and has different system conditions (different transfers, weather assumptions, load levels) than those in the operations time horizon. The results from the planning horizon SOL methodology application can therefore be quite different and either do not correspond to SOLs (different limiting elements) in the operations time horizon or have very different limiting results (voltage limit violations versus System instability). Therefore, there is little or no value to using planning horizon SOLs during operations horizon conditions.

The use of the word "Operating" within the term "System Operating Limit" when establishing limits in the planning horizon has created confusion as to which value is referred to when referencing "SOL". Is it the "planning horizon SOL" or the "operations horizon SOL"? Retiring FAC-010-3 and eliminating references to SOLs and IROLs in the planning horizon will eliminate this confusion.

Retirement of FAC-010-3

Background

The purpose of FAC-010-3 (System Operating Limits Methodology for the Planning Horizon) is to ensure that SOLs used in the reliable planning of the (BES are determined based on an established methodology or methodologies. This standard only requires a PC to have a documented SOL Methodology. FAC-014-2 Requirements R3, R4, R4.3 and R5.4 require its use. Retirement of FAC-010-3 would consequently necessitate retirement of the associated requirements in FAC-014-2.

Comprehensive Requirements of TPL-001-4

The requirements in the TPL-001-4 standard require a comprehensive Planning Assessment and includes the establishment of limits and criteria (Facility ratings, System steady-state voltage limits, and stability performance criteria) and the *methodology* used by the planners (TPL-001-4, Requirement R6) to identify System instability (Cascading, voltage instability, or uncontrolled islanding) for the planning horizon. TPL-001-4 requires that a summary of the results of the assessment (TPL-001-4, Requirement R2) and a list of critical Contingencies that are expected to produce the most severe System impacts (TPL-001-4, Requirement R4.5) be included in the Planning Assessment. Further, TPL-001-4, Requirement R8 requires that the Planning Assessment, which includes all of information listed above, be distributed to any functional entity that has a reliability related need, for which the RC qualifies.

With the introduction of TPL-001-4 in 2013, FAC-010-3 became redundant as TPL-001-4 *is an established methodology* used in the reliable planning of the BES. This comprehensive methodology describes how the transmission system should be studied, addresses the establishment of performance criteria, prescribes the outages that must be analyzed, identifies the outages that do not meet the performance requirements, and requires determination of the corrective actions that should be taken to ensure future system reliability. This established methodology meets and exceeds performance requirements identified in FAC-010-3 SOL methodology. The comprehensive nature of TPL-001-4 is seen in the following excerpts from the TPL-001-4 requirements, which correspond to FAC-010-3:

<u>Modeling</u>:

TPL-001-4, Requirement 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.”

<u>Criteria/Methodology</u>:

TPL-001-4, Requirement 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.”

TPL-001-4, Requirement 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.”

<u>Analyzed Events</u>:

TPL-001-4, Table 1 – “Steady State & Stability Performance Planning Events”

<u>Reporting</u>:

DRAFT

TPL-001-4, Requirement R2 – "Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES."

TPL-001-4, Requirement 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."

Corrective Action:

TPL-001-4, R2.7: "For the 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."

DRAFT

Prior Review of FAC-010

The June 2013 report from the Independent Experts Review Project identified FAC-010-2.1 Requirements R3, R4, and R5 as "Requirements Recommended for Retirement" in Appendix E of the report. Requirement R5 was retired effective January 21, 2014 as part of NERC's P81 project. The Independent Expert Review team consisted of five independent industry experts and a sixth participant from FERC. The relevant table entries are shown below.

FAC-010-2.1	R3.	More appropriate as a Guideline. This is a checklist.
FAC-010-2.1	R4.	More appropriate as a Guideline. Description of appropriate coordination does not rise to a Standard.
FAC-010-2.1	R5.	P81 Phase 1.

In addition, the Periodic Review Team under the NERC Project 2015-03 recommended retirement of FAC-010-3. Industry comments received and reviewed during the PRT efforts indicate significant support for the retirement of FAC-010-3 due to its redundancy.

Creation of FAC-015-1

Rationale for FAC-015-1

As noted above, the SDT identified consistency of the limits and criteria used in the planning and operations time horizons as an area in the Reliability Standards that could be improved. To that end, the SDT developed FAC-015-1 to require that the planners use limits and criteria in their Planning Assessments that are as limiting, if not more limiting, than the limits and criteria developed in accordance with the RC's SOL Methodology.

The Perceived "Gap"

The perceived *gap* stems from the concern about the potential use of limits and criteria in the planning horizon that is less conservative than that used in the operations time horizon. For example, if planners used less conservative thermal limits when planning the System to meet all-facilities-in-service, peak load conditions, then operations would potentially face Facility Rating exceedances, which may require corrective actions up to and including Load shed to operate within Facility Ratings. Failing to have limit and criteria consistency between planning and operations may result in unacceptable System performance in the operations time horizon for the same conditions that were previously deemed acceptable when assessed in the planning horizon (i.e. planning the System less conservatively than the System is operated).

There is currently no mechanism to require consistency between the limits and criteria used in the two time horizons. By requiring a direct link of coordination between the limits and criteria in the SOL Methodology in the operations horizon with the limits and criteria used in Planning Assessments, which are used for the reliable planning of the BES, reliability and consistency is improved. By retiring FAC-010-3 the coordination is directly linked and a risk for a third and potentially disparate "methodology" around limits and criteria is also removed.

Development of FAC-015-1

DRAFT

Despite the comprehensive requirements in TPL-001-4 and to address the perceived gap, the SDT developed FAC-015-1 with the title "Coordination of Planning Assessments with the RC's SOL Methodology" and the purpose "to ensure the Facility Ratings, System steady-state voltage limits, and stability criteria used in Planning Assessments are coordinated with the RC's SOL Methodology." FAC-015-1 will require the PC to implement processes that ensure that the Facility Ratings, voltage limits, and stability performance criteria used in its planning assessment are equal or more limiting than the Facility Ratings, System Voltage Limits, and stability performance criteria specified in the RC's SOL Methodology.

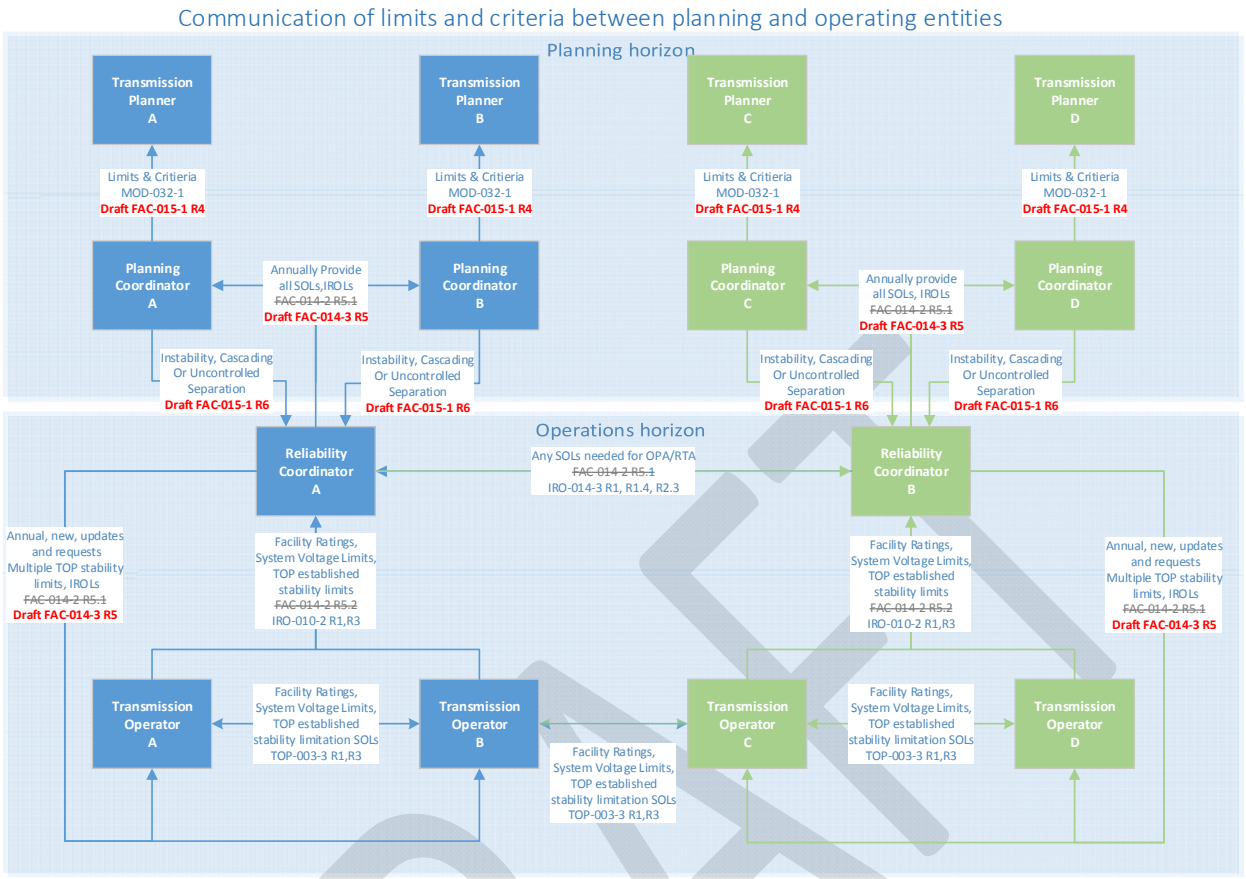
Improved Communication of Limits and Criteria Between Planning and Operating Entities

Reliability Standard FAC-014-2 Requirements R5 and R6 address communication of limits and criteria between the planning (PCs and TPs) and operating entities (RCs and TOPs). The requirements lack some clarity with respect to timing of the communication. In proposed FAC-014-3, the SDT revised Requirements R5 and R6 to simplify and streamline the PC's and TP's responsibilities for communication of limits and criteria. Proposed FAC-015-1 coordinates with proposed FAC-014-3 by identifying the necessary communication of limits and criteria between the planning and operating entities that utilize such limits and criteria. These two standards also recognize existing requirements that already address some of the necessary communication (e.g. IRO-010-2, TOP-003-3, and IRO-014-3).

The SDT is improving clarity and efficiency of communications by establishing a single point of contact between the RC and the PC for communication of SOLs from the operations horizon to the planning horizon. The PC, which is more familiar with and interacts regularly with TPs, is the entity responsible for communicating the SOLs to impacted Transmission Planners. This removes communications directly from the RC to the TPs and keeps the PC in the direct path of all SOLs from the operations time horizon. The requirements for FAC-015-1 can be thus met during times of annual preparation for its annual Planning Assessments.

The figure below shows examples of how the communication of SOLs would work given the proposed FAC-014-3 and FAC-015-1. The figure details what is communicated, direction of the communication (i.e. from whom to whom), and the respective NERC Reliability Standard Requirements that require or contain a provision for such communication. Requirements that are struck through and grayed out represent currently-effective requirements that are proposed to be replaced and/or not be retained (due to redundancy with the other referenced requirements) in FAC-014-3. Requirements that are bold and red text are proposed requirements that support or replace existing requirements for the noted communication path and content.

DRAFT



FAC-015 single standard for PCs and TPs

Currently, planning entities (PCs and TPs) have requirements in FAC-010-3 and FAC-014-2. With FAC-010-3 and FAC-014-2 Requirements R3, R4, R5.3 and R5.4 being effectively replaced by proposed FAC-015-1, the communication of stability related information identified in FAC-014-2 Requirement R6 from the PC to the RC remained. The SDT has opted to relocate the content addressed in FAC-014-2 Requirement R6 into newly proposed FAC-015-1 Requirement R6 rather than keep in FAC-014. This relocation allowed for all PC and TP requirements related to coordination of limits utilized between planning and operations time horizons to be in a single standard.

Proposed Definition of "System Voltage Limit"

Term: "System Voltage Limit"

Definition:

The maximum and minimum steady-state voltage limits (both normal and emergency) that provide for acceptable System performance.

Rationale

As noted above, the Project 2015-09 standard drafting team (SDT) also proposes to add the term System Voltage Limit to the NERC Glossary with the following definition:

> *The maximum and minimum steady-state voltage limits (both normal and emergency) that provide for acceptable System performance.*

The SDT identified a need to develop a NERC Glossary definition for the term System Voltage Limit to address confusion within industry as to what constitutes a system voltage limit. As part of its informal comment period on initial drafts of FAC-011-4 and FAC-014-3 (July 14- August 12, 2016), the SDT requested industry comment on whether there is a need to clarify what constitutes system voltage limits through a defined term in the NERC Glossary. The SDT proposed the following definition: "The maximum and minimum steady-state voltages (both Normal and Emergency) that provide for reliable system operations."

The vast majority of commenters indicated support for developing a definition for System Voltage Limits but noted a few concerns with the proposed definition. In response to those comments, the SDT made the following revisions:

- The word "limits" was added to clarify that it is a numeric value.
- The terms "Normal" and "Emergency" were changed to lower case as "Normal" is not defined in the NERC Glossary, and the SDT concluded that the NERC defined term "Emergency" was not appropriate.
- The phrase "reliable system operations" was replaced with "acceptable System performance" because the SDT determined that this language was more reflective of the desired intent behind the definition.
- The SDT used the NERC Glossary term "System" as the definition implies that System Voltage Limits should result in acceptable performance (from a voltage perspective) of the overall System.

The proposed System Voltage Limit definition does not specify whether the Transmission Operator would be required to provide a "System Voltage Limit" for each bus on its system, or if the Transmission Operator would need to provide a single high and low limit that is applicable to its entire system. The SDT intends for the Reliability Coordinator's System Operating Limits (SOL) Methodology to dictate the manner in which

System Voltage Limits should be established. The proposed definition allows Reliability Coordinators to have such flexibility, provided the requirements in proposed FAC-011-4 are met.

Additionally, the System Voltage Limit definition allows for differing time components that may be associated with short term or dynamic ratings. The SDT's intent is to allow the flexibility to establish System Voltage Limits consistent with the Reliability Coordinator's SOL Methodology, provided the requirements in proposed FAC-011-4 are met. The proposed definition specifies that System Voltage Limits must include normal and emergency maximum and minimum limits, and that these limits provide for acceptable System performance (in the context of voltage performance). According to the definition, it is acceptable for a Reliability Coordinator's SOL Methodology to allow for System Voltage Limits to include a normal limit and multiple emergency limits, which may have associated time values similar to the way emergency Facility Ratings are associated with time values. As discussed below, this concept is supported by the proposed definition of SOL Exceedance which states, in relevant par: "Bus voltage is outside the highest or lowest emergency System Voltage Limit, or outside a System Voltage Limit for which there is not sufficient time to bring the bus voltage to defined levels should the Contingency occur

Lastly, the proposed definition of System Voltage Limit does not explicitly distinguish between a voltage limit and a voltage rating. That is because proposed FAC-011-4 requires that System Voltage Limits respect equipment voltage ratings.

Potential Standards for Use of New Term: "System Voltage Limit"

These standard(s) were identified as potential areas that may benefit from the use of the new term. The SDT is in the process of evaluating these standards with respect to incorporating the definition.

- FAC-003-4 Transmission Vegetation Management
- MOD-001-2 Available Transmission System Capability
- PRC-012-2 Remedial Action Schemes
- TPL-001-4 Transmission System Planning Performance Requirements
- TPL-007-1 Transmission System Planned Performance for Geomagnetic Disturbance Events
- VAR-001-4.1 Voltage and Reactive Control

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2017-05 NUC-001-3 Periodic Review

Periodic Review Team Nomination Period Open through Tuesday, May 23, 2017

Now Available

Nominations are being sought for review team members through **8 p.m. Eastern, Tuesday, May 23, 2017.**

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

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

Periodic Review team members should expect to invest an average of approximately 10 hours per month for approximately 12 months to support this project. The first face-to-face meeting is tentatively planned for August 2017 in Atlanta, with one additional face-to-face meeting in North America, in addition to regular conference calls. Team members may also have supporting projects, either individually or by subgroup, to present to the larger team for discussion and review. Lastly, an important component of the Periodic Review effort is outreach. Members of the team will be expected to conduct industry outreach during the development process to support a successful project outcome.

Previous team experience is beneficial but not required. See the project page and nomination form for additional information.

Next Steps

The Standards Committee is expected to appoint members to the team in July 2017. Nominees will be notified shortly after they have been appointed**.**

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

For more information or assistance, contact Standards Developer, Mat Bunch (via email) or at (404) 446-9785.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

A. Introduction

1. **Title:** Cyber Security — BES Cyber System Categorization

2. **Number:** CIP-002-~~5.1a~~6

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.~~4.1.5. Reliability Coordinator

~~4.1.7.~~4.1.6. Transmission Operator

~~4.1.8.~~4.1.7. Transmission Owner

4.2. Facilities: For the purpose of the requirements contained herein, 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-~~5.1a~~6:

4.2.3.1. Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

4.2.3.2. Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

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

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

5. Effective Dates:

~~**5.1 24 Months Minimum –** CIP-002-5.1a 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.~~

~~**5.2** 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.~~

See implementation plan for CIP-002-6.

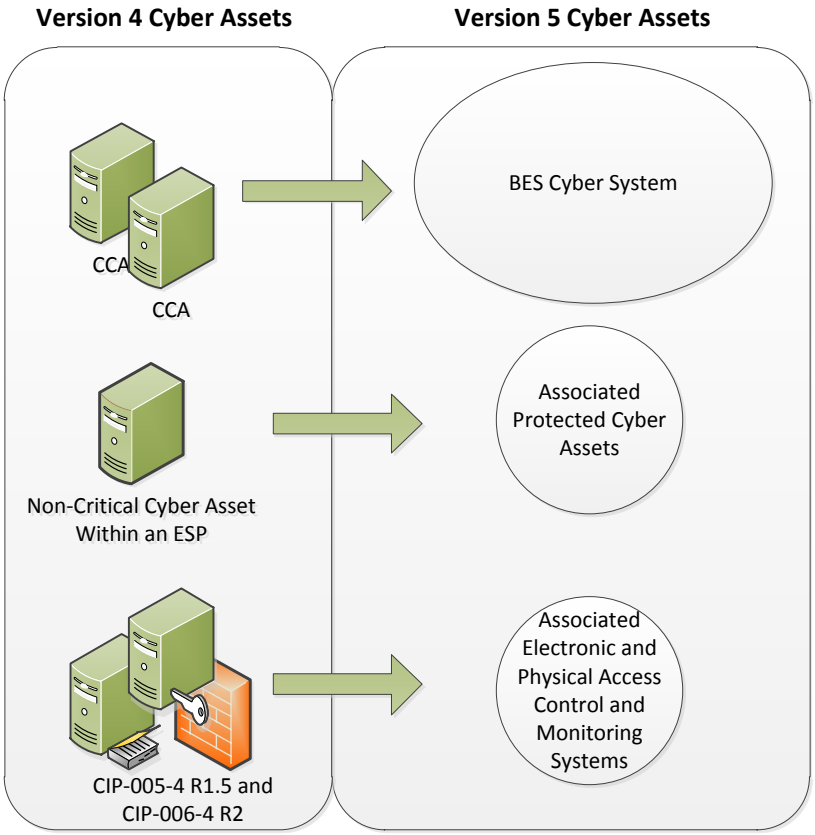
6. Background: This standard provides "bright-line" criteria for applicable Responsible Entities to categorize their BES Cyber Systems based on the impact of their associated Facilities, systems, and equipment, which, if destroyed, degraded, misused, or otherwise rendered unavailable, would affect the 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~~Remedial Action Schemes 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.

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-5.1a)			
			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 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 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-002-5.1a)			
			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	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 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	For Responsible 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	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-002-5.1a)			
			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.	categorized at a lower 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.	categorized at a lower 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-002-5.1a)			
			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

See Appendix 1. The Interpretation in Appendix 1 was developed under a prior version of the Reliability Standard, CIP-002-5.1, and is being carried forward to subsequent versions.

~~E.~~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. Approved by the NERC Board of Trustees.	Update
3	3/31/10	Approved by FERC.	
4	12/30/10	Modified to add specific criteria for Critical Asset identification.	Update
4	1/24/11	Approved by the NERC Board of Trustees.	Update
5	11/26/12	Adopted by the NERC Board 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

Version	Date	Action	Change Tracking
5.1	11/22/13	FERC Order issued approving CIP-002-5.1.	
5.1a	11/02/16	Adopted by the NERC Board of Trustees.	
5.1a	12/14/2016	FERC letter Order approving CIP-002-5.1a. Docket No. RD17-2-000.	
6	TBD		

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.

~~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.~~

Rationale for Criterion 2.12: The V5 Transition Advisory Group (V5TAG), which consisted of representatives from NERC, Regional Entities, and industry stakeholders, was formed to issue guidance regarding possible methods to achieve compliance with the CIP V5 standards and to support industry's implementation activities. During the course of the V5TAG's activities, the V5TAG identified certain issues with the CIP Reliability Standards that were more appropriately addressed by a standard drafting team (SDT) for the CIP Reliability Standards. The V5TAG developed the CIP Version 5 Transition Advisory Group Issues for Consideration document[1] to formally recommend that the SDT address these issues during the standards development process and to consider modifications to the standard language.

Among other issues, due to the confusion of the application of the phrase "used to perform the functional obligations of the Transmission Operator" in CIP-002-5.1a, Attachment 1, Criterion 2.12, the V5TAG recommended clarification of the criterion.

The Project 2016-02 Standard Drafting Team (SDT) proposes the following modifications to CIP-002-5.1a, Attachment 1, Criterion 2.12 to clarify the applicability of requirements on a TO Control Center that performs the functional obligations of a TOP.

The proposed criterion establishes a weighted value for BES Transmission Lines based on voltage class for BES Transmission Lines operated between 100 and 499 kV. The aggregate weighted value for applicable BES Cyber Systems must exceed 6000 to meet the minimum threshold established in Criterion 2.12, and can be calculated by summing the "weight value per line" shown in the associated table for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center. If the aggregate weighted value of lines exceed 6000, the Control Center's associated BES Cyber System(s) should be identified as medium impact. If the aggregate weighted value of lines do not exceed 6000, the Control Center's associated BES Cyber System(s) should be evaluated for classification as low impact pursuant to Criterion 3.1.

[1] This document is available at http://www.nerc.com/pa/Stand/Project%20201602%20Modifications%20to%20CIP%20Standards%20DL/Transfer_Issues_V5TAG-SDT_1st-final-03232016.pdf.

2.12. Control Centers or backup Control Centers, not included in High Impact Rating (H) above, that monitor and control BES Transmission Lines with an "aggregate weighted value" exceeding 6000 according to the table below. The "aggregate weighted value" for a Control Center or backup Control Center is determined by summing the "weight value per line" shown in the table below for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center.

Voltage Value of a Line	Weight Value per Line
less than 100 kV (not applicable)	(not applicable)
100 kV to 199 kV	250
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

~~2.12.~~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~~Remedial Action Schemes 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

At NERC's direction, the current draft Guidelines and Technical Basis section will be removed from the Reliability Standard template prior to final ballot. The SDT will evaluate the content for placement in a Technical Rationale document for posting along with, but separate from, the Reliability Standard. Additionally, the SDT may develop Implementation Guidance on this Reliability Standard to submit for ERO endorsement based on the content of this section.

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-~~5.1a~~6 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-~~5.1a~~6. 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-~~5.1a~~6

CIP-002-~~5.1a~~6 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-~~5.1a~~6. 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-~~5.1a~~6, 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~~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~~ associated with Control Centers and backup Control Centers, including associated data centers ~~performing the functional obligations of a~~, that monitor and control BES Transmission ~~Operator~~Lines with an aggregate weighted value of 6000 or higher, and that have not already been included in Part 1. The drafting team included additional qualifications in this criterion that would ensure the required level of impact to the BES is defined and a risk threshold associated to establish a floor for applicable medium impact BES Cyber Systems.

  The total aggregated weighted value is used to account for the impact to the BES. The 6000 aggregate weighted value threshold defined in criterion 2.12 provides a sufficient

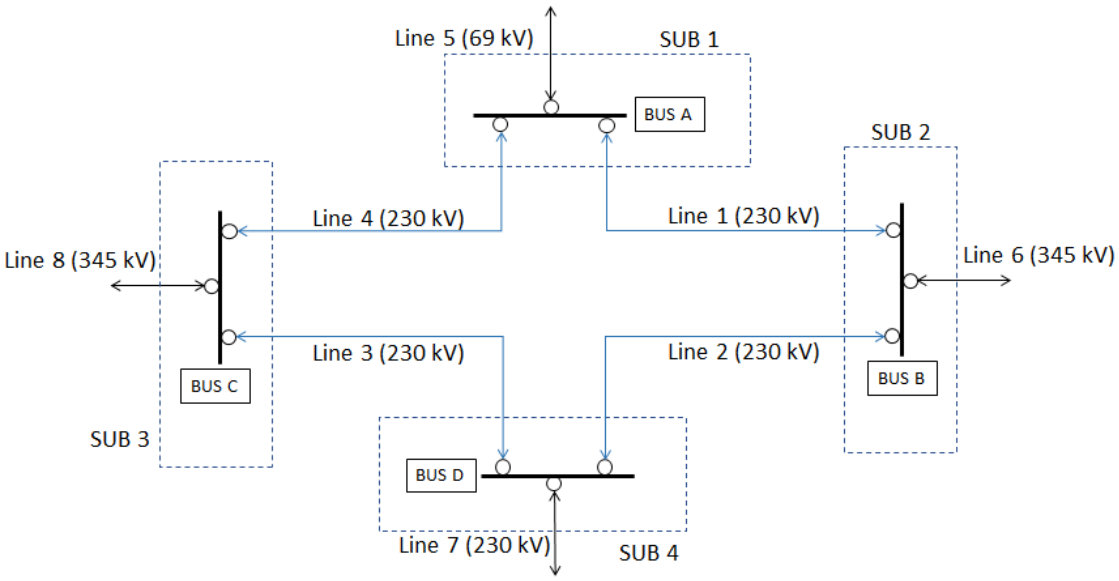
differentiation for medium and low impact BES Cyber Systems associated with Control Centers that monitor and control BES Transmission Lines. SDT analysis of Transmission Control Centers validated that those facilities that may have significant impact are categorized at an appropriate level commensurate with the associated risk.

In the terms of applicable BES Transmission Lines, the following should be considered:

- All BES Transmission Lines that are energized at voltages between 100 kV and 499 kV and are monitored and controlled by a Control Center, including associated data center(s).
- All BES Transmission Lines, including those that connect to neighboring entities, that are monitored and controlled by the Responsible Entity's Control Center, including associated data center(s).
- Multiple-point (or multiple-tap) lines are considered to contribute a single weight value per line.

Criterion 2.12 Examples:

In example 1 below, a BES Cyber System is associated with a Control Center that monitors and controls eight BES Transmission Lines. In order to calculate the Control Center's aggregate weighted value, the Responsible Entity should reference the table located in Criterion 2.12 and sum the weighted values for each BES Transmission Line.



Example 1

The weighted value for each BES Transmission Line is detailed in the following table by voltage classification. The calculation of the weighted values is demonstrated below and equates to an aggregate weighted value of 6100, which is above the minimum threshold for the medium impact rating required in Criterion 2.12. In accordance with

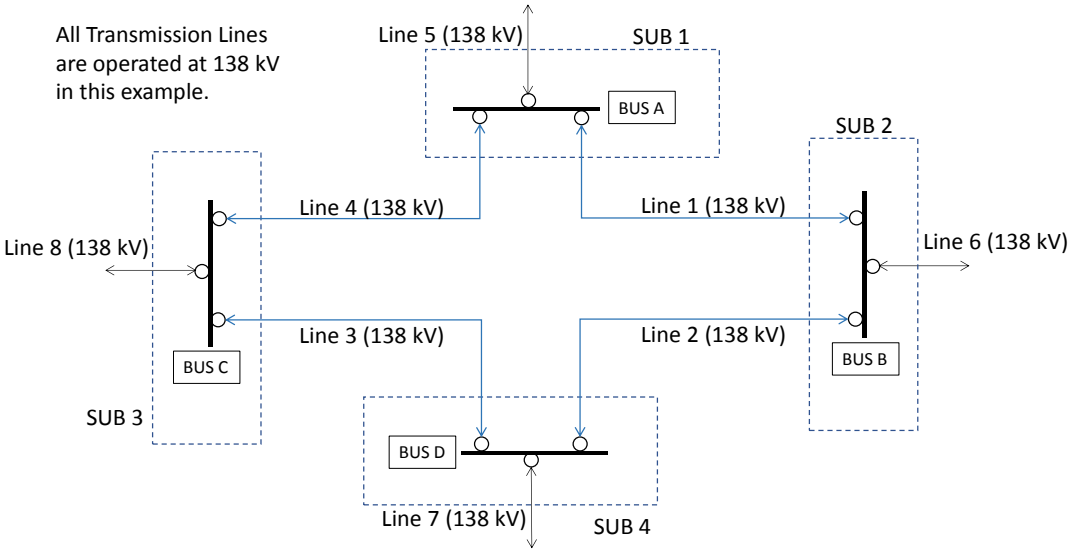
Criterion 2.12, the BES Cyber System(s) associated with the Control Center should be categorized as medium impact BES Cyber System(s).

Voltage Value of a Line	Weight Value per Line	Applicable Lines	Weighted Value
less than 100 kV (not applicable)	(not applicable)	Line 5	N/A
100 kV to 199 kV	250	None	0
200 kV to 299 kV	700	Line 1, Line 2, Line 3, Line 4, Line 7	3500
300 kV to 499 kV	1300	Line 6, Line 8	2600
500 kV and above	0	None	0

Calculation

700+700+700+700+700+1300+1300 = 6100

In the additional example below, a BES Cyber System is associated with a Control Center that monitors and controls eight BES Transmission Lines. In order to calculate the Control Center's aggregate weighted value, the Responsible Entity should reference the table located in Criterion 2.12 and sum the weighted values for each BES Transmission Line.



Example 2

The weighted value for each BES Transmission Line is detailed in the following table by voltage classification. The calculation of the weighted values is demonstrated below and equates to an aggregate weighted value of 2000, which is below the minimum threshold for a medium impact rating required in Criterion 2.12. The BES Cyber System associated with the Control Center in this example should be categorized as ~~high impact.~~ a low impact BES Cyber System pursuant to Criterion 3.1.

Voltage Value of a Line	Weight Value per Line	Applicable Lines	Weighted Value
less than 100 kV (not applicable)	(not applicable)	None	N/A
100 kV to 199 kV	250	Line 1, Line 2, Line 3, Line 4, Line 5, Line 6, Line 7, Line 8	2000
200 kV to 299 kV	700	None	0
300 kV to 499 kV	1300	None	0
500 kV and above	0	None	0

Calculation

250+250+250+250+250+250+250+250= 2000

- 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.

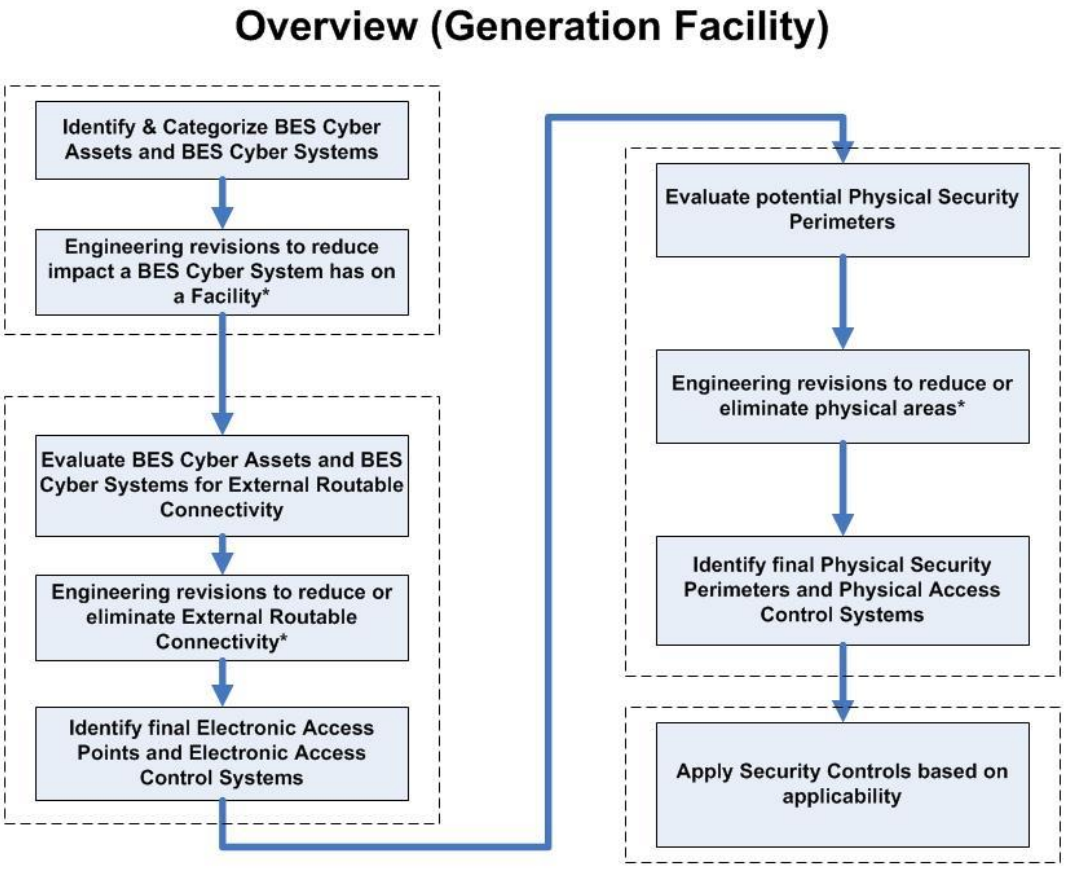
Regarding concerns of communication to BES Asset Owners and Operators of their role in the Restoration Plan, Transmission Operators are required in NERC Standard EOP-005-2 to "provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific 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.

Appendix 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~~Remedial Action Schemes 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.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2016-02 Modifications to CIP Standards
Reliability Standard CIP-002-6

Applicable Standard

- Reliability Standard CIP-002-6 - Cyber Security – BES Cyber System Categorization

Requested Retirements

- CIP-002-5.1a - Cyber Security – BES Cyber System Categorization

Prerequisite Standard

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

- None

Applicable Entities

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

Effective Date

Reliability Standard CIP-002-6 - Cyber Security – BES Cyber System Categorization

Where approval by an applicable governmental authority is required, Reliability Standard CIP-002-6 shall become effective on the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, Reliability Standard CIP-002-6 shall become effective sixty (60) days following the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Planned and Unplanned Changes

Planned changes refer to any changes of the electric system or BES Cyber System as identified through the assessment under CIP-002-6, Requirement R2, which were planned and implemented by the responsible entity.

For example, if an automation modernization activity is performed at a transmission substation, whereby Cyber Assets are installed that meet the criteria in CIP-002-6, Attachment 1, then the new BES Cyber System has been implemented as a result of a planned change, and must, therefore, be in compliance with the applicable CIP Cyber Security Standards upon the commissioning of the modernized transmission substation.

In contrast, *unplanned* changes refer to any changes of the electric system or BES Cyber System, as identified through the assessment under CIP-002-6, Requirement R2, which were not planned by the responsible entity. Consider the scenario where a particular BES Cyber System at a transmission substation does not meet the criteria in CIP-002-6, Attachment 1, then, later, an action is performed outside of that particular transmission substation; such as, a transmission line is constructed or retired, a generation plant is modified, changing its rated output, and that unchanged BES Cyber System may become a medium impact BES Cyber System based on the CIP-002-6, Attachment 1, criteria.

For *planned* changes resulting in a higher categorization, the responsible entity shall comply with all applicable requirements in the applicable CIP Cyber Security Standards on the update of the identification and categorization of the affected BES Cyber System, and any applicable and associated Physical Access Control Systems, Electronic Access Control and Monitoring Systems and Protected Cyber Assets. Initial performance of periodic requirements shall occur by the end of the specified period following the update of the identification and categorization of the affected BES Cyber System. For example, initial performance shall be within 15 months following the update of the identification and categorization of the affected BES Cyber System for requirements that must be performed at least once every 15 calendar months.

For *unplanned* changes resulting in a higher categorization, the responsible entity shall comply with all applicable requirements in the applicable CIP Cyber Security Standards, according to the following timelines, following the identification and categorization of the affected BES Cyber System and any applicable and associated Physical Access Control Systems, Electronic Access Control and Monitoring Systems and Protected Cyber Assets. Initial performance of periodic requirements shall occur by the end of the specified period following the update of the identification and categorization of the affected BES Cyber System.

Scenario of Unplanned Changes	Compliance Implementation
New high impact BES Cyber System	12 months
New medium impact BES Cyber System	12 months

Newly categorized high impact BES Cyber System from medium impact BES Cyber System	12 months for requirements not applicable to medium impact BES Cyber Systems
Newly categorized medium impact BES Cyber System from low impact BES Cyber System	12 months
Responsible entity identifies first medium impact or high impact BES Cyber System (i.e., the responsible entity previously had no BES Cyber Systems categorized as high impact or medium impact according to the CIP-002-6 identification and categorization processes)	24 months

For the purposes of transitioning from CIP-002-5.1a to CIP-002-6, increases in BES Cyber System categorization (i.e., from low to medium/high or from medium to high) from the application of CIP-002-6 Attachment 1 criteria are provided 24 months for implementation of applicable CIP Cyber-Security Standards.

Retirement Date

Reliability Standard CIP-002-5.1a

Reliability Standard CIP-002-5.1a shall be retired immediately prior to the effective date of Reliability Standard CIP-002-6 in the particular jurisdiction in which the revised standard is becoming effective.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

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 **CIP-002-6**. 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-002-6, Requirement R1	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of High was assigned to this requirement. The VRF is not being modified for this requirement. A VRF of high is appropriate due to foundational nature of CIP-002-6 as the basis of a Responsible Entity's CIP management program.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	N/A
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	N/A
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	The VRF is not being modified for this requirement. The modification is a clarification of Criterion 2.12 of Attachment 1 to CIP-002-6.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The VRF is not being modified for this requirement. A VRF of high is appropriate due to foundational nature of CIP-002-6 in support of a Responsible Entity's CIP management program. The modification is a clarification of Criterion 2.12 of Attachment 1 to CIP-002-6.
FERC VRF G5 Discussion	N/A

VRF Justifications for CIP-002-6, Requirement R1	
Proposed VRF	**High**
Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	

VSLs for CIP-002-6, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
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 Systems, five percent or fewer of identified BES Cyber Systems	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 Entities with more than a total of 100 high	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 Entities with more than a total of 100 high or	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 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, 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 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.	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 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	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 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	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 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.

	Systems, more than five but less than or equal to 10 high or medium BES Cyber Systems have not been identified.	Systems, more than 10 but less than or equal to 15 high or medium BES Cyber Systems have not been identified.	

VSL Justifications for CIP-002-6 Requirements R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSL has not been modified for this requirement since there is no change to Requirement R1. The modification is a clarification of Criterion 2.12 of Attachment 1 to CIP-002-6.
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 VSL has not been modified for this requirement since there is no change to Requirement R1. 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 VSL has not been modified for this requirement since there is no change to Requirement R1. The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL has not been modified for this requirement since there is no change to Requirement R1. The VSLs are based on a single violation, and not cumulative violations.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Project 2016-02 Consideration of Issues and Directives

CIP V5 Issues for Standard Drafting Team Consideration[1]

From experience in the CIP Version 5 Transition Study and on-going implementation efforts, the CIP Version 5 Transition Advisory Group (V5TAG) identified specific issues with the CIP Version 5 standard language that caused difficulty implementing the requirements. The V5TAG members found that some of the language within the CIP Version 5 standards could be interpreted in more than one way. These interpretations, that could alter the perceived context or intent of the requirements, went beyond acceptable, customary levels of standard language flexibility. To address this, the V5TAG presented the issue to the standard drafting team for its consideration.

The Standard Drafting Team modified Standard CIP-002-6 to address the issue of Transmission Owner (TO) Control Centers performing the functional obligations of the Transmission Operator (TOP).

Issues from CIP V5 Issues for Standard Drafting Team Consideration	
Issue Language	**Consideration of Issue**
CIP-002-5.1, Attachment 1 Control Center criteria for additional clarity and for possible revisions related to TOP or TO Control Centers performing the functional obligations of a TOP, in particular for small or lower-risk entities. A potential revision could be a size for criteria 2.12, Control Centers performing the functional obligations of a TOP.	The Project 2016-02 Standard Drafting Team (SDT) revised Reliability Standard CIP-002-6, Attachment 1, Criterion 2.12 to address all Control Centers and backup Control Centers of Transmission, regardless of registration. The revision provides a bright line threshold that categorizes BES Cyber Systems associated with Control Centers of Transmission as medium impact. The

[1] This document is available at http://www.nerc.com/pa/Stand/Project%20201602%20Modifications%20to%20CIP%20Standards%20DL/Transfer_Issues_V5TAG-SDT_1st-final-03232016.pdf

Issues from CIP V5 Issues for Standard Drafting Team Consideration	
Issue Language	**Consideration of Issue**
	reference to Transmission Operator has been removed to provide clarity.
Clarify the applicability of requirements on a TO Control Center that perform the functional obligations of a TOP, particularly if the TO has the ability to operate switches, breakers and relays in the BES. Review the corresponding Guidelines and Technical Basis of CIP-002-5.1, specifically: the "CIP-002-5" section paragraph starting with "Responsibility for the reliable operation of the BES is spread across all Entity Registrations"; the table following that paragraph; the "High Impact Rating (H)" section; and the criterion bullets for Control Centers under the "Medium Impact Rating (M)" section.	The revised Reliability Standard CIP-002-6, Attachment 1, Criterion 2.12 provides a bright line threshold that categorizes BES Cyber Systems associated with Control Centers of Transmission as medium impact. All other BES Cyber Systems associated with Control Centers of Transmission that do not exceed the bright line threshold will be categorized as low impact. Based on this categorization, the requirements applicable to the Control Center's BES Cyber Systems are clearly defined through the Applicable Systems language throughout Standards CIP-003 through CIP-011.
The definition of Control Center (if pursued, recognize possible impacts on operations and planning standards and/or glossary terms that include 'Control Center', for example, the revised Glossary term for "System Operator" to be effective July 1, 2016).	The SDT is considering revisions to the definition of Control Center, but asserts that the modifications to Criterion 2.12 of CIP-002-6, Attachment 1, effectively address the concerns raised by the V5TAG regarding Transmission Owner Control Centers.
The language scope of "perform the functional obligations of" throughout the Attachment 1 criteria.	The SDT contends that the issue raised by the V5TAG is uniquely associated with small Transmission Owner Control Centers and Transmission Operator Control Centers. Therefore, Reliability Standard CIP-002-5.1a, Attachment 1, Criteria 1.1, 1.2, 1.3, 1.4, 2.11, and 2.13 are sufficiently clear and do not need modification.

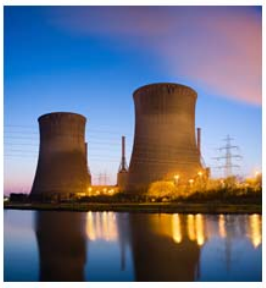
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

DRAFT Reliability Standards Development Plan

2018-2020

June 2017

RELIABILITY | ACCOUNTABILITY



3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Table of Contents

Background iii
Executive Summary iv
2017 Progress Report 1
FERC Directives 1
Projects Completed in 2017 1
2018 Projects 2
Projects Continuing from 2017 into 2018 2
High Priority 2
Medium Priority 2
Low Priority 2
Projects Commencing in 2018 3
Standards Grading Metrics 4
Attachment 1 5
Final Grades for Standards Graded in 2017 5

Background

The 2017–2019 Reliability Standards Development Plan (RSDP) continued progress toward NERC's goal to develop a stable set of clear, concise, technically sound, and results-based NERC Reliability Standards and to retire requirements that do little to promote reliability. The 2017-2019 RSDP specifically highlighted the importance of the Integration of Variable Generation Task Force and Essential Reliability Services Working Group (ERSWG) recommendations and called for continued communication with the Reliability Issues Steering Committee (RISC) on emerging risks. The 2017-2019 RSDP also indicated that most of the work in the next three years would focus on Periodic Reviews and recognized there may be new or emerging risks identified that would generate new standards development projects. The addition of the Standards Grading Metric in 2016 informs the Periodic Reviews as to the quality and content of the standards.[1]

The 2017-2019 RSDP also recognized the importance of addressing subsequent directives from applicable regulatory authorities including the Federal Energy Regulatory Commission (FERC), Standard Authorization Requests (SARs), and the value of enhanced communication through industry feedback loops. It also stressed that Periodic Reviews and standards development activities would occur at a measured pace, compared to the level of activity and pace of standards development during previous years, and they will be aligned with strategic considerations of reviewing standard families that are interrelated.[2]

As described herein, the 2018-2020 RSDP builds upon the goals of the 2017-2019 RSDP, adding an additional objective of enhanced consideration of cost effectiveness in standards development.

Pursuant to section 310 of the NERC Rules of Procedure, NERC is required to develop and provide to applicable governmental authorities an annual RSDP for Reliability Standards development. Each annual RSDP must include a progress report comparing results achieved to the prior year's RSDP. NERC is required to consider the comments and priorities of the applicable governmental authorities in developing and updating the annual RSDP. NERC also provides the RSDP to the NERC Standards Committee (SC) for review and posts the RSDP for industry comment.

[1] The Periodic Review standing review team will grade the standards. The team includes representatives from NERC, the Regional Entities, and the NERC technical committees. Grading occurs prior to conducting the Periodic Review.

[2] In some cases, a narrower review of a standard will likely be appropriate. For example, there are not necessarily other interrelated standards with FAC-003.

Executive Summary

The 2018–2020 RSDP recognizes the diligent work of the last few years in transforming the body of NERC Reliability Standards into a mature state while shifting its focus to Periodic Reviews, FERC directives, emerging risks, SARs, and the standards grading initiative. The 2018-2020 RSDP also contemplates that the work of the various NERC technical committees and working groups thereunder, may result in one or more SARs and subsequent standards projects.

As with the 2017-2019 RSDP, Periodic Reviews will occur at a measured pace compared to the level of activity and pace of standards development during recent years. Additionally, Periodic Reviews will be aligned with strategic considerations of reviewing standard families that are interrelated. The Standards Grading Metric and "Final Grades for Standards Graded in 2017" (Attachment 1) help to inform the Periodic Reviews as to the quality and content of the standards.[3]

The 2018-2020 RSDP also includes plans for completing the Periodic Reviews initiated in 2016 and 2017, and for commencing additional Periodic Reviews in 2018.

While most of the work in the next three years will focus on Periodic Reviews, there may be new or emerging risks identified that would generate new standards development projects. NERC will continue to seek input and recommendations from the RISC with regard to emerging or potential risks to BES reliability that may require revisions to existing standards or new standards development. To help determine impact of potential risk to BES reliability, NERC will use various feedback mechanisms, including but not limited to, feedback from the Compliance Monitoring and Enforcement Program, RISC profiles, Events Analysis and Compliance violation statistics, as well as any published "Lessons Learned." The Regional Entities also have feedback mechanisms in place to solicit comments from industry and to help identify approaches to meet concerns and provide input to the standards. Standards input will continue to be coordinated with the North American Energy Standards Board as appropriate.

NERC is committed to enhancing and refining cost effectiveness considerations in the standards development process during the 2018-2020 period. For example, during 2016 and 2017, NERC conducted two cost effectiveness pilots.[4] NERC continues to develop and implement its cost effectiveness process, which has been implemented more broadly in standards development and will continue to evolve during this work plan period. Cost effectiveness questions are also part of the Periodic Reviews and SAR process. NERC will continue to look for ways to enhance or refine the review and implementation of cost effectiveness during the standards development process in a way that is productive and does not unduely burden the industry for data and input.

This 2018-2020 RSDP provides insight into standards development activities anticipated at the time of publication, so that stakeholders may make available appropriate resources to accomplish these standards development objectives. Additional activities such as Requests for Interpretation and Regional Variance development may impact the plan. In order to help the industry understand resource requirements for each project, the RSDP now shows time frames and anticipated resources for each project under development.

[3] The Periodic Review standing review team grades the standards prior to conducting Periodic Reviews. The team includes representatives from NERC, the Regions, and NERC technical committees. If there is a recommended change in the standard due to Periodic Review recommendations and subject to the standards development process, the Periodic Review standing review team will re-grade the standard with the revised language.

[4] Information on NERC's cost effectiveness initiative can be found at: http://www.nerc.com/pa/Stand/Pages/CostEffectivenessPilot.aspx.

2017 Progress Report

Pursuant to section 310 of the NERC Rules of Procedure, NERC offers the following progress report on Reliability Standards development in 2017.

FERC Directives

As of June 14, 2017, there are 29 outstanding FERC directives. Additionally, FERC has issued directives pertaining to issues outside of NERC standards. These additional directives are being addressed by the NERC technical committees and other NERC departments (e.g., topics related to reliability assessment, performance analysis, etc.), which are not reflected in this total.

Projects Completed in 2017

The 2017–2019 RSDP identified nine projects initiated in 2017 or continued from 2016. All of the projects listed therein have been completed in 2016 or are planned to be completed in 2017 except for Project 2013-03 Geomagnetic Disturbance Mitigation, Project 2015-09 Establish and Communicate System Operating Limits, Project 2015-10 Single Points of Failure, and Project 2016-02 Modifications to CIP Standards. Additional project information is available on the NERC website on the Standards page.[5]

The following projects have been or are planned to be completed in 2017 (actual and anticipated NERC Board of Trustees (Board) adoption dates are noted)**:**

Projects from the 2017-2019 RSDP

1. Project 2015-08 Emergency Operations – EOP-004, EOP-005, EOP-006, EOP-008 (adopted by the Board in February 2017)
2. Project 2016-01 Modifications to TOP and IRO Standards – TOP-001, IRO-002 (adopted by the Board in February 2017)
3. Project 2016-03 Cyber Security Supply Chain Management – CIP-013-1 (Board adoption expected in August 2017)
4. Project 2016-EPR-01 Enhanced Periodic Review of Personnel Performance, Training, and Qualifications Standards - PER-001, PER-003, and PER-004
5. Project 2016-EPR-02 Enhanced Periodic Review of Voltage and Reactive Standards - VAR-001 and VAR-002

[5] As of the date of publication, the subject web page resides at http://www.nerc.com/pa/Stand/Pages/default.aspx.

2018 Projects

Projects Continuing from 2017 into 2018

In determining high, medium, or low priority to designate projects as listed in this RSDP, the following factors were taken into consideration.

1. Outstanding regulatory directives with filing deadlines (High Priority)
2. RISC category rankings of high impact with consideration of probability of occurrence (High or Medium Priority)
3. Potential reliability risk from stakeholders provided through feedback mechanism (High, Medium or Low Priority, based on the risk)
4. Outstanding regulatory directives without regulatory deadlines or "soft directives" such as considerations (High or Medium Priority)
5. Outstanding requirements that are known candidates for retirement (Medium or Low Priority)
6. Any known adverse content and quality assessments (likely Low Priority, as any reliability gaps identified have already been addressed)

High Priority

- Project 2013-03 Geomagnetic Disturbance Mitigation - TPL-007-2 (drafting estimated to be completed by April 1, 2018[6] requiring approximately 11 industry subject matter experts for approximately 120 work hours[7] each for the remaining part of this project)
    - FERC established a deadline of 18 months from the effective date of Order No. 830 for completing the revisions, which is May 2018
- Project 2016-02: Modifications to CIP Standards (drafting estimated to be completed by May 1, 2018 requiring approximately 10 industry subject matter experts or approximately 75 work hours each for the remaining part of this project)

Medium Priority

- Project 2015-09 Establish and Communicate System Operating Limits- FAC-010, FAC-011, FAC-014 (drafting estimated to be completed by April 1, 2018 requiring approximately 10 industry subject matter experts or approximately 100 work hours each for the remaining part of this project)
- Project 2015-10 Single Points of Failure - TPL-001 (drafting estimated to be completed by April 1, 2018 requiring approximately 10 industry subject matter experts or approximately 60 work hours each for the remaining part of this project)
- 2016-04 Modifications to PRC-025-1 (drafting estimated to be completed by April 1, 2018 requiring approximately 6 industry subject matter experts for approximately 60 work hours each for the remaining part of this project)

Low Priority

- Project 2016-EPR-01 Enhanced Periodic Review of Personnel Performance, Training, and Qualifications Standards - PER-001, PER-003, and PER-004 (drafting estimated to be completed by April 1, 2018

[6] The "estimated drafting completed by" date is NERC's estimate of the final ballot date.
[7] The "work hours" estimates apply to 2018 only.

requiring approximately 10 industry subject matter experts for approximately 40 work hours each for the remaining part of this project)

- Project 2017-03 FAC-008 Periodic Review (drafting estimated to be completed by August 1, 2018 requiring approximately 10 industry subject matter experts for approximately 100 work hours each for the remaining part of this project)
- Project 2017-04 Periodic Review of Interchange Scheduling and Coodination Standards - INT-004, INT-006, INT-009 and INT-010 (drafting estimated to be completed by August 1, 2018 requiring approximately 10 industry subject matter experts for approximately 80 work hours each for the remaining part of this project)
- Project 2017-05 Periodic Review of NUC-001-3 (drafting estimated to be completed by May 1, 2018 requiring approximately eight industry subject matter experts for approximately 60 work hours each for the remaining part of this project)

Projects Commencing in 2018

At least two Periodic Reviews should commence in 2018.

The following 31 standards will be eligible for periodic review in 2018:

BAL-005-02b	IRO-006-5	MOD-008-1	MOD-030-3	PRC-019-2
BAL-006-2	IRO-008-2	MOD-020-0	MOD-031-2	TOP-002-4
CIP-014-2	IRO-010-2	MOD-025-2	MOD-033-1	TOP-003-3
FAC-003-4	IRO-014-3	MOD-026-1	PER-001-1.1(ii)	
FAC-010-3	IRO-017-1	MOD-027-1	PRC-002-2	
FAC-013-2	MOD-001-1a	MOD-028-2	PRC-015-1	
IRO-001-4	MOD-004-1	MOD-029-2a	PRC-016-1	

Additionally, SARs, emerging risks to the Bulk Power System, and FERC regulatory directives that may occur subsequent to publishing this RSDP may prompt additional projects in 2018.

Standards Grading Metrics

The NERC SC endorsed a grading system for standards as a metric on March 9, 2016. The grading is conducted by the Periodic Review Standing Review Team (PRSRT) as set forth in the Periodic Review process. The PRSRT is comprised of the following:

- SRT chair: SC chair or (or SC chair delegate)
- Operating Committee (OC) chair (or OC chair delegate)
- Planning Committee (PC) chair (or PC chair delegate)
- NERC staff
- Representation from the Regional Entities

The grading metrics include possible scores of 0-3 for quality and 0-13 for content. The set of standards chosen each year for grading, according to the criteria in the above section, will be reviewed and their grading will be used to prioritize and determine the sequence they should enter into the Periodic Review process. At least one industry comment period will take place to allow industry to comment on the grading performed by the PRSRT. The grades, based on the PRSRT and any industry input will be finalized, appended to the RSDP, and used to complete the prioritization each year.

Attachment 1

Final Grades for Standards Graded in 2017 (placeholder)

Standard and Requirement	Content Average	Quality Average

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2017-03 FAC-008-3 Periodic Review

Periodic Review Team Nomination Period Open through May 23, 2017

Now Available

Nominations are being sought for review team members through **8 p.m. Eastern, Tuesday, May 23, 2017**.

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

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

The time commitment for this project is expected to be 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 team sets forth. Team members may also have side projects, either individually or by sub-group, to present for discussion and review. Lastly, an important component of the team effort is outreach. Members of the team will be expected to conduct industry outreach during the development process to support a successful ballot.

Previous team experience is beneficial but not required. See the project page and nomination form for additional information.

Next Steps

The Standards Committee is expected to appoint members to the team in July 2017. Nominees will be notified shortly after they have been appointed.

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

For more information or assistance, contact Senior Standards Developer, Al McMeekin (via email) or at (404) 446-9675.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower

Atlanta, GA 30326
404-446-2560 | www.nerc.com

2017 Standard Grading Summary

Standard | Requirement		OC	PC	RE	NERC	Avg.	Max Dif	OC	PC	RE	NERC	Avg.	Max Dif
		Content Questions						Quality Questions					
BAL-003-1.1	R1	3	3	2	3	2.75	**1**	13	13	13	13	13	**0**
BAL-003-1.1	R2	3	3	3	3	3.00	**0**	13	13	13	13	13	**0**
BAL-003-1.1	R3	3	2	3	3	2.75	**1**	13	13	13	13	13	**0**
BAL-003-1.1	R4	3	2	3	3	2.75	**1**	13	13	13	13	13	**0**
COM-001-2.1	R1	3	2	3	3	2.75	**1**	13	11	13	13	12.5	**2**
COM-001-2.1	R2	3	2	3	3	2.75	**1**	13	12	13	13	12.75	**1**
COM-001-2.1	R3	3	3	3	3	3.00	**0**	13	13	13	13	13	**0**
COM-001-2.1	R4	3	3	3	3	3.00	**0**	13	13	13	13	13	**0**
COM-001-2.1	R5	3	3	3	3	3.00	**0**	13	13	13	13	13	**0**
COM-001-2.1	R6	3	3	3	3	3.00	**0**	13	13	13	13	13	**0**
COM-001-2.1	R7	3	3	3	3	3.00	**0**	13	13	13	13	13	**0**
COM-001-2.1	R8	3	3	3	3	3.00	**0**	13	13	13	13	13	**0**
COM-001-2.1	R9	3	3	3	3	3.00	**0**	11	13	13	13	12.5	**2**
COM-001-2.1	R10	3	3	3	3	3.00	**0**	12	13	13	13	12.75	**1**
COM-001-2.1	R11	3	3	2	3	2.75	**1**	13	13	10	13	12.25	**3**
COM-002-4	R1	3	3	2	3	2.75	**1**	11	13	13	13	12.5	**2**
COM-002-4	R2	3	3	3	3	3.00	**0**	13	13	13	13	13	**0**
COM-002-4	R3	3	3	3	3	3.00	**0**	13	13	13	13	13	**0**
COM-002-4	R4	3	3	3	3	3.00	**0**	13	13	12	13	12.75	**1**
COM-002-4	R5	3	3	3	3	3.00	**0**	12	13	12	13	12.5	**1**
COM-002-4	R6	3	3	3	3	3.00	**0**	12	13	12	13	12.5	**1**
COM-002-4	R7	3	3	3	3	3.00	**0**	12	13	12	13	12.5	**1**
FAC-001-2	R1	3	3	2	3	2.75	**1**	13	10	13	13	12.25	**3**
FAC-001-2	R2	3	3	3	3	3.00	**0**	13	10	13	13	12.25	**3**
FAC-001-2	R3	3	3	3	3	3.00	**0**	13	10	12	13	12	**3**
FAC-001-2	R4	3	3	3	3	3.00	**0**	13	10	11	13	11.75	**3**
FAC-002-2	R1	3	2	3	3	2.75	**1**	13	13	12	13	12.75	**1**
FAC-002-2	R2	3	2	3	3	2.75	**1**	13	13	12	13	12.75	**1**
FAC-002-2	R3	3	2	2	3	2.50	**1**	13	13	12	13	12.75	**1**
FAC-002-2	R4	3	2	3	3	2.75	**1**	13	13	12	13	12.75	**1**
FAC-002-2	R5	3	2	3	3	2.75	**1**	13	13	12	13	12.75	**1**
IRO-009-2	R1	3	3	3	3	3.00	**0**	13	12	13	13	12.75	**1**
IRO-009-2	R2	3	3	3	3	3.00	**0**	13	12	13	13	12.75	**1**
IRO-009-2	R3	3	3	3	3	3.00	**0**	13	12	13	13	12.75	**1**
IRO-009-2	R4	3	3	3	3	3.00	**0**	13	12	13	13	12.75	**1**
MOD-032-1	R1	3	2	1	2	2.00	**2**	13	13	11	13	12.5	**2**
MOD-032-1	R2	3	2	2	2	2.25	**1**	13	13	13	13	13	**0**
MOD-032-1	R3	3	2	2	2	2.25	**1**	13	13	13	13	13	**0**
MOD-032-1	R4	3	2	3	3	2.75	**1**	13	13	12	13	12.75	**1**
TPL-001-4	R1	3	3	3	3	3.00	**0**	13	13	12	13	12.75	**1**
TPL-001-4	R2	3	3	2	3	2.75	**1**	13	13	10	13	12.25	**3**
TPL-001-4	R3	3	2	3	3	2.75	**1**	13	11	10	13	11.75	**3**
TPL-001-4	R4	3	2	3	3	2.75	**1**	13	11	11	13	12	**2**
TPL-001-4	R5	3	3	3	3	3.00	**0**	13	13	11	13	12.5	**2**
TPL-001-4	R6	3	3	3	3	3.00	**0**	13	13	11	13	12.5	**2**
TPL-001-4	R7	3	3	3	3	3.00	**0**	13	13	10	13	12.25	**3**
TPL-001-4	R8	3	3	2	3	2.75	**1**	13	13	11	13	12.5	**2**

Standard Number	Requirement Number	Text of Requirement *(if text is incomplete, please use entire requirement pasted on NERC.com)*	Supports a Reliability Objective (as defined by the Reliability Principles) (Yes or No)	Meets the Paragraph 81 criteria* (Yes or No)	Appropriate as a guide rather than a standard? (Yes or No)	Content Questions from the Standards Independent Experts Report Q1 (Yes or No) Is the content of the requirement technically correct, including identifying who does what and when?	Q2 (Yes or No) Are the correct functional entities identified?	Q3 (Yes or No) Are the appropriate actions, for which there should be accountability, included or is there a gap?	Quality Questions from the Standards Independent Experts Report Q4 (Yes or No) Should the requirement stand alone or, is it or should it be consolidated with other standards?	Q5 (Yes or No) Is it written as a results-based standard (RBS) requirement (states what, not prescriptive, capability) and does it follow the VRS format (e.g., sub-requirement structure)?	Q6 (Yes or No) Is it technologically neutral?	Q7 (Yes or No) Are the expectations for each function clear?	Q8 (Yes or No) Does the requirement align with the purpose?	Q9 (Yes or No) Is it a higher solution than the lowest common denominator?	Q10 (Yes or No) Is it measurable?	Q11 (Yes or No) Does it have a technical basis in engineering and operations?	Q12 (Yes or No) Is it complete and self-contained?	Q13 (Yes or No) Is the language clear and direct, not contain ambiguous or outdated terms?	Q14 (Yes or No) Can it be practically implemented?	Q15 (Yes or No) Does it use consistent terminology?	Q16 (Yes or No) Is the standard used effective in achieving the reliability purpose or objective of the Standard and mitigating the risk to the BES?	Content Score 0-3	Quality Score 0-12	Comment/Rationale
BAL-003-1.1	R1	R1: Each Frequency Response Sharing Group (FRSG) or Balancing Authority that is not a member of a FRSG shall achieve an annual Frequency Response Measure (FRM) (as calculated and reported in accordance with Attachment A) that is equal to or more negative than its Frequency Response Obligation. The Frequency Response Obligation for a Frequency Response is provided by each FRSG or BA that is not a member of a FRSG to maintain Interconnection Frequency Response equal to or more negative than the Interconnection Frequency Response Obligation. [Risk Factor: High][Time Horizon:Real-time Operations]	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	12	Balancing Authorities and groups of BAs are the logical place to put this obligation.
BAL-003-1.1	R2	R2: Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting shall maintain a Frequency Bias Setting that is, to the extent practical, equal to Attachment A, as validated by the ERO, into its Area Control Error (ACE) calculation during the implementation period specified by the ERO and shall use this Frequency Bias Setting until directed to change by the ERO. [Risk Factor:Medium][Time Horizon: Operations Planning]	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	12	This is the essence of coordinated frequency operations in a multiple BA interconnect.
BAL-003-1.1	R3	R3: Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and is utilizing a variable Frequency Bias Setting shall maintain a Frequency Bias Setting that is: [Risk Factor: Medium][Time Horizon: Operations Planning] R3.1: Less than zero at all times, and R3.2: Equal to or more negative than its Frequency Response Obligation when frequency varies from 60 Hz by more than +/- 0.036 Hz.	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	12	Necessary to identify bounds for variable frequency bias.
BAL-003-1.1	R4	R4: Each Balancing Authority that is performing Overlap Regulation Service shall modify its Frequency Bias Setting in its ACE calculation, or order to represent the Frequency Bias Setting for the combined Balancing Authority Area, to be equivalent to either: [Risk Factor: Medium][Time Horizon: Operations Planning] • The sum of the Frequency Bias Settings as shown on FRS Form 1 and FRS Form 2 for the participating Balancing Authorities as validated by the ERO, or • The Frequency Bias Setting shown on FRS Form 1 and FRS Form 2 for the entirety of the participating Balancing Authorities' Areas.	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	12	Technical description of the requirements allowing overlap regulation. This wouldn't be necessary if overlap regulation were not allowed.
COM-001-2.1	R1	R1: Each Reliability Coordinator shall have Interpersonal Communication capability with the following entities (unless the Reliability Coordinator detects a failure of its Interpersonal Communication capability in which case Requirement R10 shall apply): [Violation Risk Factor: High] [Time Horizon: Real-time Operations]. R1.1.: All Transmission Operators and Balancing Authorities within its Reliability Coordinator Area. R1.2.: Each adjacent Reliability Coordinator within the same Interconnection.	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	12	Note: I was on this SDT. We wanted to put this into certification, but FERC's opinion at the time was that registration wasn't enforceable.
COM-001-2.1	R2	R2: Each Reliability Coordinator shall designate an Alternative Interpersonal Communication capability with the following entities: [Violation Risk Factor: High][Time Horizon: Real-time Operations] R2.1.: All Transmission Operators and Balancing Authorities within its Reliability Coordinator Area. R2.2.: Each adjacent Reliability Coordinator within the same Interconnection.	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	12	I was on this SDT. It does feel very administrative and unduly burdensome as a standard, when a simple guide that says that you ought to back up critical communication systems would be sufficient.
COM-001-2.1	R3	R3: Each Transmission Operator shall have Interpersonal Communication capability with the following entities (unless the Transmission Operator detects a failure of its Interpersonal Communication capability in which case Requirement R10 shall apply): [Violation Risk Factor: High] [Time Horizon: Real-time Operations]. R3.1.: Its Reliability Coordinator. R3.2.: Each Balancing Authority within its Transmission Operator Area. R3.3.: Each Distribution Provider within its Transmission Operator Area. R3.4.: Each Generator Operator within its Transmission Operator Area. R3.5.: Each adjacent Transmission Operator synchronously connected. R3.6.: Each adjacent Transmission Operator asynchronously connected.	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	Note: I was on this SDT. We wanted to put this into certification, but FERC's opinion at the time was that registration wasn't enforceable.
COM-001-2.1	R4	R4: Each Transmission Operator shall designate an Alternative Interpersonal Communication capability with the following entities: [Violation Risk Factor: High] [Time Horizon: Real-time Operations]. R4.1.: Its Reliability Coordinator. R4.2.: Each Balancing Authority within its Transmission Operator Area. R4.3.: Each adjacent Transmission Operator synchronously connected. R4.4.: Each adjacent Transmission Operator asynchronously connected.	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	I was on this SDT. It does feel very administrative and unduly burdensome as a standard, when a simple guide that says that you ought to back up critical communication systems would be sufficient.
COM-001-2.1	R5	R5: Each Balancing Authority shall have Interpersonal Communication capability with the following entities (unless the Balancing Authority detects a failure of its Interpersonal Communication capability in which case Requirement R10 shall apply): [Violation Risk Factor: High] [Time Horizon: Real-time Operations]. R5.1.: Its Reliability Coordinator. R5.2.: Each Transmission Operator that operates Facilities within its Balancing Authority Area. R5.3.: Each Distribution Provider within its Balancing Authority Area. R5.4.: Each Generator Operator that operates Facilities within its Balancing Authority Area. R5.5.: Each adjacent Balancing Authority.	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	Note: I was on this SDT. We wanted to put this into certification, but FERC's opinion at the time was that registration wasn't enforceable.
COM-001-2.1	R6	R6: Each Balancing Authority shall designate an Alternative Interpersonal Communication capability with the following entities: [Violation Risk Factor: High] [Time Horizon:Real-time Operations]. R6.1.: Its Reliability Coordinator. R6.2.: Each Transmission Operator that operates Facilities within its Balancing Authority Area. R6.3.: Each Adjacent Balancing Authority.	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	I was on this SDT. It does feel very administrative and unduly burdensome as a standard, when a simple guide that says that you ought to back up critical communication systems would be sufficient.
COM-001-2.1	R7	R7: Each Distribution Provider shall have Interpersonal Communication capability with the following entities (unless the Distribution Provider detects a failure of its Interpersonal Communication capability in which case Requirement R11 shall apply): [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]. R7.1.: Its Balancing Authority. R7.2.: Its Transmission Operator.	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	Note: I was on this SDT. We wanted to put this into certification, but FERC's opinion at the time was that registration wasn't enforceable.
COM-001-2.1	R8	R8: Each Generator Operator shall have Interpersonal Communication capability with the following entities (unless the Generator Operator detects a failure of its Interpersonal Communication capability in which case Requirement R11 shall apply): [Violation Risk Factor: High] [Time Horizon: Real-time Operations]. R8.1.: Its Balancing Authority. R8.2.: Its Transmission Operator.	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	Note: I was on this SDT. We wanted to put this into certification, but FERC's opinion at the time was that registration wasn't enforceable.
COM-001-2.1	R9	R9: Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall test its Alternative Interpersonal Communication capability at least once each calendar month. If the test is unsuccessful, the responsible entity shall initiate action to repair or designate a replacement Alternative Interpersonal Communication capability within 2 hours. [Violation Risk Factor: Medium][Time Horizon: Real-time Operations, Same-day Operations]	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	3	13	This could easily be a guide. The testing of backup communications presumes that the primary communications medius is functional - so I doubt this to be a Medium Risk and it is overly prescriptive when the only point is to make sure your backup comms are functioning.
COM-001-2.1	R10	R10: Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall notify entities as identified in Requirements R1, R3, and R5, respectively within 60 minutes of the detection of a failure of its Interpersonal Communication capability that lasts 30 minutes or longer. [Violation Risk Factor: Medium][Time Horizon: Real-time Operations]	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	This one is a necessary requirement in a mandatory compliance environment, but the time limits are arbitrary and that creates unnecessary grief. 31 minutes, an hour, both of these could be acceptable equipment outage time limits.
COM-001-2.1	R11	R11: Each Distribution Provider and Generator Operator that detects a failure of its Interpersonal Communication capability shall consult each entity affected by the failure, as identified by the Distribution Provider or Generator Operator, within 60 minutes of the detection of the failure, to determine a mutually agreeable action for the restoration of its Interpersonal Communication capability. [Violation Risk Factor: Medium][Time Horizon: Real-time Operations]	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	This could easily be a guide. Just tell them to contact their BA/TOP and works something out as a backup (cell phone or something similar.)
COM-002-4	R1	R1: Each Balancing Authority, Reliability Coordinator, and Transmission Operator shall develop documented communications protocols for its operating personnel that issue and receive Operating Instructions. The protocols shall, at a minimum: [Violation Risk Factor: Low][Time Horizon: Long-term Planning] R1.1.: Require its operating personnel that issue oral or oral or written Operating Instruction to use the English language, unless agreed to otherwise. An alternate language may be used for internal operations. R1.2.: Require its operating personnel that issue an oral two-party, person-to-person Operating Instruction to take one of the following actions: • Confirm the receiver's response if the repeated information is correct. • Reissue the Operating Instruction if the repeated information is incorrect or if requested by the receiver, or • Take an alternative action if a response is not received or if the Operating Instruction was not understood by the receiver. R1.3.: Require its operating personnel that issue oral two-party, person-to-person Operating Instruction to take one of the following actions: • Repeat, not necessarily verbatim, the Operating Instruction and receive confirmation from the issuer that the response was correct, or • Request that the issuer reissue the Operating Instruction. R1.4.: Require its operating personnel that issue a written or oral single-party to multiple-party burst Operating Instruction to confirm or verify that the Operating Instruction was received by at least one receiver of the Operating Instruction. R1.5.: Specify the instances that require time identification when issuing an oral or written Operating Instruction and the format for that time identification. R1.6.: Specify the nomenclature for Transmission interface Elements and Transmission Interface Facilities when issuing an oral or written Operating Instruction.	Yes	No	Yes	Yes	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	3	13	This never should have included three part communications in the requirement. The English part is okay. Three part should have been a guide and strongly encouraged. FERC Lowered this requirement during the SDT. What they did not understand is that this is only a problem during some other requirement violation, not at any other time. Publishing a guide and enforcing the other, core reliability requirements with extra emphasis when they are violated in part by communication issues is a better approach. We've elevated mundane speech and consequently deemphasized the important speech.
COM-002-4	R2	R2: Each Balancing Authority, Reliability Coordinator, and Transmission Operator shall conduct initial training for each of its operating personnel responsible for the Realtime operation of the interconnected Bulk Electric System on the documented communications protocols developed in Requirement R1 prior to that individual operator issuing an Operating Instruction. [Violation Risk Factor: Low][Time Horizon: Long-term Planning]	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	Governs emergencies - okay here.
COM-002-4	R3	R3: Each Distribution Provider and Generator Operator shall conduct initial training for each of its operating personnel who can receive an oral two-party, person-to-person Operating Instruction prior to that individual operator receiving an oral two-party, person-to-person Operating Instruction to either: [Violation Risk Factor: Low][Time Horizon: Long-term Planning] • Repeat, not necessarily verbatim, the Operating Instruction and receive confirmation from the issuer that the response was correct, or • Request that the issuer reissue the Operating Instruction.	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	Governs emergencies - okay here.
COM-002-4	R4	R4: Each Balancing Authority, Reliability Coordinator, and Transmission Operator shall at least once every twelve (12) calendar months: [Violation Risk Factor:Medium][Time Horizon: Operations Planning] R4.1.: Assess adherence to the documented communications protocols in Requirement R1 by its operating personnel that issue and receive Operating Instructions, and provide feedback to those operating personnel and take corrective action, as deemed appropriate by the entity, to address deviations from the documented protocols. R4.2.: Assess the effectiveness of its documented communications protocols in Requirement R1 for its operating personnel that issue and receive Operating Instructions and modify its documented communication protocols, as necessary.	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	Governs emergencies - okay here.
COM-002-4	R5	R5: Each Balancing Authority, Reliability Coordinator, and Transmission Operator that issues an oral two-party, person-to-person Operating Instruction during an Emergency, excluding written or oral single-party to multiple-party burst Operating Instructions, shall either: [Violation Risk Factor: High][Time Horizon: Real-time Operations] • Confirm the receiver's response if the repeated information is correct (in accordance with Requirement R6). • Reissue the Operating Instruction if the repeated information is incorrect or if requested by the receiver, or • Take an alternative action if a response is not received or if the Operating Instruction was not understood by the receiver.	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	3	12	Should have been a guide.
COM-002-4	R6	R6: Each Balancing Authority, Distribution Provider, Generator Operator, and Transmission Operator that receives an oral two-party, person-to-person Operating Instruction during an Emergency, excluding written or oral single-party to multiple-party burst Operating Instructions, shall either: [Violation Risk Factor: High][Time Horizon: Real-time Operations] • Repeat, not necessarily verbatim, the Operating Instruction and receive confirmation from the issuer that the response was correct, or • Request that the issuer reissue the Operating Instruction.	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	3	12	Should have been a guide.
COM-002-4	R7	R7: Each Balancing Authority, Reliability Coordinator, and Transmission Operator that issues a written or oral single-party to multiple-party burst Operating Instruction during an Emergency shall confirm or verify that the Operating Instruction was received by at least one receiver of the Operating Instruction. [Violation Risk Factor:High][Time Horizon: Real-time Operations]	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	3	12	Should have been a guide.
FAC-001-2	R1	R1: Each Transmission Owner shall document Facility interconnection requirements, update them as needed, and make them available upon request. Each Transmission Owner's Facility interconnection requirements shall address interconnection requirements for: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] R1.1. generation Facilities; R1.2.: transmission Facilities; and R1.3. end-user Facilities.	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	I wonder about why we need this series of standards while FERC also has a LGIA and SGIA?
FAC-001-2	R2	R2: Each applicable Generator Owner shall document Facility interconnection requirements and make them available upon request within 45 calendar days of full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system. [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	I wonder about why we need this series of standards while FERC also has a LGIA and SGIA?
FAC-001-2	R3	R3: Each Transmission Owner shall address the following items in its Facility interconnection requirements: [Violation Risk Factor: Lower] [Time Horizon: Long-Term Planning] R3.1.: Procedures for coordinated studies of new or materially modified existing interconnections and their impacts on affected system(s). R3.2.: Procedures for notifying those responsible for the reliability of affected system(s) of new interconnections.	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	I wonder about why we need this series of standards while FERC also has a LGIA and SGIA?
FAC-001-2	R4	R4: Each applicable Generator Owner shall address the following items in its Facility interconnection requirements: [Violation Risk Factor: Lower] [Time Horizon: Long-Term Planning] R4.1.: Procedures for coordinated studies of new interconnections and their impacts on affected system(s). R4.2.: Procedures for notifying those responsible for the reliability of affected system(s) of new interconnections.	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	I wonder about why we need this series of standards while FERC also has a LGIA and SGIA?
FAC-002-2	R1	R1: Each Transmission Planner and each Planning Coordinator shall study the reliability impact of: (i) interconnecting new generation, transmission, or electricity end-user Facilities and (ii) materially modifying existing interconnections of transmission Facilities or electricity end-user Facilities. The following shall be studied: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] R1.1.: The reliability impact of the new interconnection, or materially modified existing interconnection, on affected system(s); R1.2.: Adherence to applicable NERC Reliability Standards, regional and Transmission Owner planning criteria, and Facility interconnection requirements; R1.3.: Steady-state, short-circuit, and dynamics studies, as necessary, to evaluate system performance under both normal and contingency conditions; and R1.4.: Study assumptions, system performance, alternatives considered, and coordinated recommendations. While these studies may be performed independently, the results shall be evaluated and coordinated by the entities involved.	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	I wonder about why we need this series of standards while FERC also has a LGIA and SGIA?
FAC-002-2	R2	R2: Each Generator Owner seeking to interconnect new generation Facilities, or to materially modify existing interconnections of generation Facilities, shall coordinate and cooperate on studies with its Transmission Planner or Planning Coordinator, including but not limited to the provision of data as described in R1, Parts 1.2-1.4. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	I wonder about why we need this series of standards while FERC also has a LGIA and SGIA?
FAC-002-2	R3	R3: Each Transmission Owner, each Distribution Provider, and each Load-Serving Entity seeking to interconnect new transmission Facilities or electricity end-user Facilities, or to materially modify existing interconnections of transmission Facilities or electricity end-user Facilities, shall coordinate and cooperate on studies with its Transmission Planner or Planning Coordinator, including but not limited to the provision of data as described in R1, Parts 1.1-1.4. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	I wonder about why we need this series of standards while FERC also has a LGIA and SGIA?
FAC-002-2	R4	R4: Each Transmission Owner shall coordinate and cooperate with its Transmission Planner or Planning Coordinator on studies regarding requested new or materially modified interconnections to its Facilities, including but not limited to the provision of data as described in R1, Parts 1.1-1.4. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	I wonder about why we need this series of standards while FERC also has a LGIA and SGIA?
FAC-002-2	R5	R5: Each applicable Generator Owner shall coordinate and cooperate with its Transmission Planner or Planning Coordinator on studies regarding requested interconnections to its Facilities, including but not limited to the provision of data as described in R1, Parts 1.1-1.4. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	I wonder about why we need this series of standards while FERC also has a LGIA and SGIA?
IRO-009-2	R1	R1: For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability Coordinator shall have one or more Operating Processes, Procedures, or Plans that identify actions the Reliability Coordinator shall take or actions the Reliability Coordinator shall direct others to take (up to and including load shedding): [Violation Risk Factor: Medium] [Time Horizon: Operations Planning or Same Day Operations] R1.1.: That can be implemented in time to prevent the identified IROL exceedance. R1.2.: To mitigate the magnitude and duration of an IROL exceedance such that the IROL exceedance is relieved within the IROL's Tv.	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
IRO-009-2	R2	R2: Each Reliability Coordinator shall initiate one or more Operating Processes, Procedures, or Plans (not limited to the Operating Processes, Procedures, or Plans developed for Requirement R1) that are intended to prevent an IROL exceedance, as identified in the Reliability Coordinator's Real-time monitoring or Real-time Assessment. [Violation Risk Factor: High] [Time Horizon: Real-time Operations]	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
IRO-009-2	R3	R3: Each Reliability Coordinator shall act or direct others to act so that the magnitude and duration of an IROL exceedance is mitigated within the IROL's Tv, as identified in the Reliability Coordinator's Real-time monitoring or Real-time Assessment. [ViolationRisk Factor: High] [Time Horizon: Real-time Operations]	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
IRO-009-2	R4	R4: Each Reliability Coordinator shall operate to the most limiting IROL and Tv in instances where there is a difference in the values identified by different Reliability Coordinators for the responsible for that Facility (or group of Facilities). [Violation Risk Factor: High] [Time Horizon: Real-time Operations]	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
MOD-032-1	R1	R1:Each Planning Coordinator and each of its Transmission Planners shall jointly develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for the Planning Coordinator's planning area that include: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning] R1.1.: The data listed in Attachment 1; R1.2.: Specifications of the following items consistent with procedures for building the interconnection-wide case(s): R1.2.1.: Data format; R1.2.2.: Level of detail to which equipment shall be modeled; R1.2.3.: Case types or scenarios to be modeled; and R1.2.4.: A schedule for submission of data at least once every 13 calendar months. R1.3.: Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those entities responsible for providing the data.	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
MOD-032-1	R2	R2: Each Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, and Transmission Service Provider in the Planning Coordinator's area, and each of its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1 for data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. [Violation Risk Factor: Medium] [Time Horizon:Long-term Planning]	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
MOD-032-1	R3	R3: Upon receipt of written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2, including the technical basis or reason for the technical concerns, each notified Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider shall respond to the notifying Planning Coordinator or Transmission Planner as follows: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] R3.1.: Provide either updated data or an explanation with a technical basis for maintaining the current data. R3.2.: Provide the response within 90 calendar days of receipt, unless a longer time period is agreed upon by the notifying Planning Coordinator or Transmission Planner.	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
MOD-032-1	R4	R4: Each Planning Coordinator shall make available models for its planning area reflecting data provided to it under Requirement R2 to the Electric Reliability Organization (ERO) or its designee to support creation of the interconnection-wide case(s) that includes the Planning Coordinator's planning area. [Violation Risk Factor: Medium] [Timehorizon: Long-term Planning]	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
TPL-001-4	R1	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 the data used for the Planning Assessment, the MOD-032 and MOD-033 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] R1.1.: System models shall represent: R1.1.1.: Existing Facilities R1.1.2.: Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months. R1.1.3.: New planned Facilities and changes to existing Facilities R1.1.4.: Real and reactive Load forecasts R1.1.5.: Known commitments for Firm Transmission Service and Interchange R1.1.6.: Resource (supply or demand side) required for Load	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
TPL-001-4	R2	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 analysis, short-circuit analysis, and Stability analysis. [Violation Risk Factor: High] [Time Horizon: Long-term Planning] R2.1.: 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: R2.1.1.: System peak Load for either Year One or year two, and for year five. R2.1.2.: System Off-Peak Load for one of the five years. R2.1.3.: P1 events in Table 1, with no Contingency modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled. R2.1.4.: 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: • Generator output level and 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. R2.2.5.: When an entity's bank equipment regularly counts near 0 in the unavailability of	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
TPL-001-4	R3	and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizon portions of the steady-state, Part 3.1.1 and 3.1.2. The studies shall be based on computer simulation models using data provided in Requirement R1. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] R3.1.: 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. R3.2.: Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.3. R3.3.: Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall: R3.3.1.: 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: R3.3.2.1.: 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 voltage ride-through capability. Include in the assessment any assumptions made. R3.3.2.2.: Tripping of Transmission elements where relay loadability limits are exceeded. R3.3.2.: Simulate the expected automatic operation of existing and planned device 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. R3.4.: Document assumptions, and summarize steady-state, dynamics, and short-circuit analysis results 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. R3.4.1.: The Planning Coordinator and Transmission Planner shall coordinate with adjacent	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
TPL-001-4	R4	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] R4.1.: 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. R4.1.1.: 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. R4.1.2.: 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. R4.1.3.: For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner. R4.2.: Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.3. R4.3.: Contingency analyses

TPL-001-4	R6	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]	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13			
TPL-001-4	R7	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]	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13			
TPL-001-4	R8	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 need and that submits a written request for the information within 30 days of such a request. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] R8.1. 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.	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13			

Standard Number	Requirement Number	Text of Requirement *(if text is incomplete, please cut entire requirement pasted on NERC.com)*	Supports a Reliability Objective (as defined by the Reliability Principles)	Meets the Paragraph 81 criteria? (Yes or No)	Appropriate as a guide rather than a standard? (Yes or No)	Content Questions from the Standards Independent Experts Report Q1 (Yes or No) Is the content of the requirement technically correct, including identifying who does what and when?	Q2 (Yes or No) Are the correct functional entities identified?	Q3 (Yes or No) Are the appropriate actions, for which there should be accountability, included in them a gap?	Should the requirement stand alone as it is or should it be combined with other standards?	Is it: A) effect vs a multi-tiered standard (R6); requirement (performance, risk (prevention) or capability) and does it follow the NRS format (e.g., sub-requirement structure)?	Is it technologically neutral?	Are the expectations for each function clear?	Does the requirement align with the purpose?	Is it a higher solution than the lowest common denominator?	Is it measurable?	Does it have a technical basis in engineering and operations?	Is it complete and self-contained?	Is the language clear and does not contain ambiguous or outdated terms?	Can it be practically implemented?	Does it use consistent terminology?	Is the Standard cost effective in achieving the reliability purpose? Have you considered the cost and mitigating the risk to the BES?	Content Score 0-3	Quality Score 0-12	Comment/Rationale
BAL-003-1.1	R1	R1: Each Frequency Response Sharing Group (FRSG) or Balancing Authority that is not a member of a FRSG shall achieve an annual Frequency Response Measure (FRM) (as calculated and reported in accordance with Attachment A) that is equal to or more negative than its Frequency Response Obligation (FRO) to ensure that sufficient Frequency Response is provided by each FRSG or BA that is not a member of a FRSG to maintain Interconnection Frequency Response equal to or more negative than the Interconnection Frequency Response Obligation. [Risk Factor: High] [Time Horizon Real-time Operations]	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
BAL-003-1.1	R2	R2: Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting shall implement the Frequency Bias Setting determined in accordance with Attachment A, as validated by the ERO, into its Area Control Error (ACE) calculation during the implementation period specified by the ERO and shall use this Frequency Bias Setting until directed to change by the ERO. [Risk Factor: Medium] [Time Horizon: Operations Planning]	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
BAL-003-1.1	R3	R3: Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and is utilizing a variable Frequency Bias Setting shall implement a variable Frequency Bias Setting that is: [Risk Factor: Medium] [Time Horizon: Operations Planning] R3.1: Less than zero at all times, and R3.2: Equal to or more negative than its Frequency Response Obligation when Frequency varies from 60 Hz by more than +/- 0.036 Hz.	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	2	13	There was a confusion on the interpretation of applicability on Interconnection versus Area
BAL-003-1.1	R4	R4: Each Balancing Authority that is performing Overlap Regulation Service shall modify its Frequency Bias Setting in its ACE calculation, in order to represent the Frequency Bias Setting for the combined Balancing Authority Area, by one of the following methods: either: [Risk Factor: Medium] [Time Horizon: Operations Planning] • The sum of the Frequency Bias Settings as shown on FRS Form 1 and FRS Form 2 for the participating Balancing Authorities as validated by the ERO; or • The Frequency Bias Setting shown on FRS Form 1 and FRS Form 2 for the entirety of the participating Balancing Authorities' Areas.	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	2	13	There was a confusion on the interpretation of applicability on Interconnection versus Area
COM-001-2.1	R1	R1: Each Reliability Coordinator shall have Interpersonal Communication capability with the following entities (unless the Reliability Coordinator detects a failure of its Interpersonal Communication capability in which case Requirement R10 shall apply): [Violation Risk Factor: High] [Time Horizon: Real-time Operations] R1.1.: All Transmission Operators and Balancing Authorities within its Reliability Coordinator Area. R1.2.: Each adjacent Reliability Coordinator within the same Interconnection.	Yes	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes	Yes	Yes	Yes	no	Yes	Yes	2	11	ICC is too broadly interpreted, guidance should show acceptable examples, not generically applied
COM-001-2.1	R2	R2: Each Reliability Coordinator shall designate an Alternative Interpersonal Communication capability with the following entities: [Violation Risk Factor: High] [Time Horizon: Real-time Operations] R2.1.: All Transmission Operators and Balancing Authorities within its Reliability Coordinator Area. R2.2.: Each adjacent Reliability Coordinator within the same Interconnection.	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	2	12	RCs need to be directed to include communications to other RCs in other Interconnections where appropriate. Single entity RC/Interconnections are proof of this.
COM-001-2.1	R3	R3: Each Transmission Operator shall have Interpersonal Communication capability with the following entities (unless the Transmission Operator detects a failure of its Interpersonal Communication capability in which case Requirement R13 shall apply): [Violation Risk Factor: High] [Time Horizon: Real-time Operations] R3.1.: Its Reliability Coordinator. R3.2.: Each Balancing Authority within its Transmission Operator Area. R3.3.: Each Distribution Provider within its Transmission Operator Area. R3.4.: Each Generator Operator within its Transmission Operator Area. R3.5.: Each adjacent Transmission Operator synchronously connected. R3.6.: Each adjacent Transmission Operator asynchronously connected.	Yes	Yes	Yes	Yes		Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
COM-001-2.1	R4	R4: Each Transmission Operator that designates an Alternative Interpersonal Communication capability with the following entities: [Violation Risk Factor: High] [Time Horizon: Real-time Operations] R4.1.: Each Balancing Authority within its Transmission Operator Area. R4.2.: Each adjacent Transmission Operator synchronously connected. R4.3.: Each adjacent Transmission Operator asynchronously connected.	Yes	Yes	Yes	Yes		Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
COM-001-2.1	R5	R5: Each Balancing Authority shall have Interpersonal Communication capability with the following entities (unless the Balancing Authority detects a failure of its Interpersonal Communication capability in which case Requirement R10 shall apply): [Violation Risk Factor: High] [Time Horizon: Real-time Operations] R5.1.: Its Reliability Coordinator. R5.2.: Each Transmission Operator that operates Facilities within its Balancing Authority Area. R5.3.: Each Distribution Provider within its Balancing Authority Area. R5.4.: Each Generator Operator that operates Facilities within its Balancing Authority Area. R5.5.: Each Adjacent Balancing Authority.	Yes	Yes	Yes	Yes		Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
COM-001-2.1	R6	R6: Each Balancing Authority that designates an Alternative Interpersonal Communication capability with the following entities: [Violation Risk Factor: High] [Time Horizon: Real-time Operations] R6.1.: Its Reliability Coordinator. R6.2.: Each Transmission Operator that operates Facilities within its Balancing Authority Area. R6.3.: Each Adjacent Balancing Authority.	Yes	Yes	Yes	Yes		Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
COM-001-2.1	R7	R7: Each Distribution Provider shall have Interpersonal Communication capability with the following entities (unless the Distribution Provider detects a failure of its Interpersonal Communication capability in which case Requirement R11 shall apply): [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations] R7.1.: Its Balancing Authority. R7.2.: Its Transmission Operator.	Yes	Yes	Yes	Yes		Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
COM-001-2.1	R8	R8: Each Generator Operator shall have Interpersonal Communication capability with the following entities (unless the Generator Operator detects a failure of its Interpersonal Communication capability in which case Requirement R11 shall apply): [Violation Risk Factor: High] [Time Horizon: Real-time Operations] R8.1.: Its Balancing Authority. R8.2.: Its Transmission Operator.	Yes	Yes	Yes	Yes		Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
COM-001-2.1	R9	R9: Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall test its Alternative Interpersonal Communication capability at least once each calendar month. If the test is unsuccessful, the responsible entity shall initiate action to repair or designate a replacement Alternative Interpersonal Communication capability within 2 hours. [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations, Same-day Operations]	Yes	Yes	Yes	Yes		Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
COM-001-2.1	R10	R10: Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall notify entities as identified in Requirements R1, R3, and R5, respectively within 60 minutes of the detection of a failure of its Interpersonal Communication capability that lasts 30 minutes or longer. [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations].	Yes	Yes	Yes	Yes		Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
COM-001-2.1	R11	R11: Each Distribution Provider and Generator Operator that detects a failure of its Interpersonal Communication capability shall consult each entity affected by the failure, as identified in Requirement R7 for a Distribution Provider or Requirement R8 for a Generator Operator, to determine a mutually agreeable action for the restoration of its Interpersonal Communication capability. [Violation Risk Factor: Medium][Time Horizon: Real-time Operations]	Yes	Yes	Yes	Yes		Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
FAC-002-2	R1	R1: Each Transmission Planner and each Planning Coordinator shall study the reliability impacts of new interconnections, new generation Facilities, and materially modified existing and (2) materially modifying existing interconnections of generators, transmission, and electricity end-user Facilities. The following shall be studied: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] R1.1.: The reliability impact of the new interconnection, or materially modified existing interconnection, on affected system(s). R1.2.: Adherence to applicable NERC Reliability Standards, regional and Transmission Planner criteria, and Facility Interconnection Requirements resulting from; R1.3.: Steady-state, short-circuit, and dynamics studies, as necessary, to evaluate system performance under both normal and contingency conditions; and R1.4.: Study assumptions, system performance, alternatives considered, and coordinated recommendations. While these studies may be performed independently, the results shall be evaluated and coordinated by the entities involved.	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes		Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	2	13	The applicability is not clear as it may require entities to duplicate work of one another. Suggest - PC in coordination with the TP, instead of saying PC and TP. Also, when the requirement specifies TP or PC, what if the other doesn't get told.
FAC-002-2	R2	R2: Each Generator Owner seeking to interconnect new generation Facilities, or to materially modify existing interconnections of generation Facilities, shall coordinate and cooperate on studies with its Transmission Planner or Planning Coordinator, including but not limited to the provision of data as described in R1, Parts 1.1-1.4. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes		Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	2	13	
FAC-002-2	R3	R3: Each Transmission Owner, each Distribution Provider, and each Load-Serving Entity, seeking to interconnect new transmission Facilities, or to materially modify existing or materially modify existing interconnections of transmission Facilities or electricity end-user Facilities, shall coordinate and cooperate on studies with its Transmission Planner or Planning Coordinator, including but not limited to the provision of data as described in R1, Parts 1.1-1.4. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes		Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	2	13	
FAC-002-2	R4	R4: Each Transmission Owner shall coordinate and cooperate with its Transmission Planner or Planning Coordinator on studies regarding requested new or materially modified interconnections to its Facilities, including but not limited to the provision of data as described in R1, Parts 1.1-1.4. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes		Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	2	13	
FAC-002-2	R5	R5: Each applicable Generator Owner shall coordinate and cooperate with its Transmission Planner or Planning Coordinator on studies regarding requested interconnections to its Facilities, including but not limited to the provision of data as described in R1, Parts 1.1-1.4. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	2	13	
IRO-009-2	R1	R1: For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability Coordinator shall have one or more Operating Processes, Procedures, or Plans that identify actions the Reliability Coordinator shall take or actions the Reliability Coordinator shall direct others to take (up to and including load shedding). [Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Real-time Operations] R1.1.: That can be implemented in time to prevent the identified IROL exceedance. R1.2.: To mitigate the magnitude and duration of an IROL exceedance such that the IROL exceedance is relieved within the IROL's Tv.	Yes	Yes	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	12	Where appropriate, this standard should be looked at to consolidate with IRO-008
IRO-009-2	R2	R2: Each Reliability Coordinator shall initiate one or more Operating Processes, Procedures, or Plans (not limited to the Operating Processes, Procedures, or Plans developed for Requirement R1) that are intended to prevent an IROL exceedance, as identified in the Reliability Coordinator's Real-time monitoring or Real-time Assessment. [Violation Risk Factor: High] [Time Horizon: Real-time Operations]	Yes	Yes	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	12	Where appropriate, this standard should be looked at to consolidate with IRO-009
IRO-009-2	R3	R3: Each Reliability Coordinator shall act or direct others to act so that the magnitude and duration of an IROL exceedance is mitigated within the IROL's Tv, as identified in the Reliability Coordinator's Real-time monitoring or Real-time Assessment. [Violation Risk Factor: High] [Time Horizon: Real-time Operations]	Yes	Yes	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	12	Where appropriate, this standard should be looked at to consolidate with IRO-010
IRO-009-2	R4	R4: Each Reliability Coordinator shall operate to the most limiting IROL and Tv in instances where there is a difference in an IROL or its Tv between Reliability Coordinators that are responsible for that Facility (or group of Facilities). [Violation Risk Factor: High] [Time Horizon: Real-time Operations]	Yes	Yes	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	12	Where appropriate, this standard should be looked at to consolidate with IRO-011
MOD-032-1	R1	R1.Each Planning Coordinator and each of its Transmission Planners shall jointly develop steady-state, dynamics, and short-circuit modeling data requirements and reporting procedures for the Planning Coordinator's planning area that include [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]: R1.1.: The data listed in Attachment 1. R1.2.: Specifications of the following items consistent with procedures for building the Interconnection-wide case(s): R1.2.1.: Data format; R1.2.2.: Level of detail to which equipment shall be modeled; R1.2.3.: Case types or scenarios to be modeled; and R1.2.4.: A schedule for submission of data at least once every 13 calendar months. R1.3.: Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those entities responsible for providing the data.	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	2	13	ERO needs to be dropped from the applicability of the standard
MOD-032-1	R2	R2. Each Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short-circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. [Violation Risk Factor: Medium] [Time Horizon:Long-term Planning]	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	2	13	ERO needs to be dropped from the applicability of the standard
MOD-032-1	R3	R3. Upon receipt of written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2, including the technical basis or reason for the technical concerns, each notified Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider shall respond to the notifying Planning Coordinator or Transmission Planner as follows. [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] R3.1.: Provide either updated data or an explanation with a technical basis for maintaining the current data. R3.2.: Provide the response within 90 calendar days of receipt, unless a longer time period is agreed upon by the notifying Planning Coordinator or Transmission Planner.	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	2	13	ERO needs to be dropped from the applicability of the standard

MOD-032-1	R4	R4: Each Planning Coordinator shall make available models for its planning area reflecting data provided to it under Requirement R2 to the Electric Reliability Organization (ERO) or its designee to support creation of the Interconnection-wide case(s) that includes the Planning Coordinator's planning area. [Violation Risk Factor: Medium] [Timeframe: Long-term Planning]	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	2	13	ERO needs to be dropped from the applicability of the standard
TPL-001-4	R1	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 required by other Requirements of this standard. The models shall represent System conditions. This establishes Category P0 as the normal System condition in Table 1 [Violation Risk Factor: High] [Time Horizon: Long-term Planning] R1.1.: System models shall represent: R1.1.1.: Existing Facilities R1.1.2.: Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months. R1.1.3.: New planned Facilities and changes to existing Facilities R1.1.4.: Real and reactive Load forecasts R1.1.5.: Known commitments for firm Transmission Service and Interchange R1.1.6.: Resources (supply or demand-side) required for Load	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
TPL-001-4	R2	Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R1, Part 2.6), document assumptions, and document summarized results of the steady state analysis, short circuit analysis, and Stability analyses. [Violation Risk Factor: High] [Time Horizon: Long-term Planning] R2.1.: 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 address the following periods: R2.1.1.: System peak Load for either Year One or year two, and for year five. R2.1.2.: System Off-Peak Load for one of the five years. R2.1.3.: 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. R2.1.4.: For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, the Planning Assessment shall model and document the conditions and system topology 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 reasonable change in System response: • Real and reactive forecasted Load. • Expected transfers. • Expected in-service status of Transmission Facilities. • Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios.•ICControllable Loads and Demand Side Management. • Duration or timing of known Transmission outages. R2.1.5.: When an entity's spare-equipment strategy could result in the unavailability of	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
TPL-001-4	R3	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] R3.1.: 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 3.3. R3.2.: 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. R3.3.: Contingency analysis for Requirement R3, Parts 3.1 & 3.2 shall: R3.3.1.: 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 analysis shall include the impact of subsequent: R3.3.1.1.: 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. R3.3.1.2.: Tripping of Transmission elements where relay loadability limits are exceeded. R3.3.2.: 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, static var devices, and switched shunts. [Violation Risk Factor: Medium] R3.4.: 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. R3.4.1.: The Planning Coordinator and Transmission Planner shall coordinate with adjacent	Yes	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	no	Yes	no	2	11	The question here is in the conduct of all extreme cases being measured. Is it all necessary?
TPL-001-4	R4	Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analysis 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] R4.1.: 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 4.3. R4.1.1.: 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. R4.1.2.: 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 element other than the generating unit and its directly connected facilities. R4.1.3.: For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner. R4.2.: 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. R4.3.: Contingency analysis for Requirement R4, Parts 4.1 and 4.2 shall: R4.3.1.: 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 analysis shall include the impact of subsequent: R4.3.1.1.: Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a fault where high speed reclosing is utilized. R4.3.1.2.: 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.	Yes	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	no	Yes	no	2	11	The question here is in the conduct of all extreme cases being measured. Is it all necessary?
TPL-001-4	R5	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. These criteria shall include, but are not limited to, 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]	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
TPL-001-4	R6	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]	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
TPL-001-4	R7	R7: Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identifyeach entity's individual and joint responsibilities for performing the required studies for the Planning Assessment. [Violation Risk Factor: Low] [Time Horizon:Long-term Planning]	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
TPL-001-4	R8	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 information within 30 days of such a request. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] R8.1.: 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.	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	

| Number | Title | Name | Yes/No/Abstain | Yes/No/Abstain | Yes/No/Abstain

Standard Number	Requirement Number	Text of Requirement *If text is incomplete, please cut entire requirement posted on NERC.com*	Supports a Reliability Objective (as defined by the Reliability Principles) (Yes or No)	Meets the Paragraph 81 criteria? (Yes or No)	Appropriate as a guide rather than a standard? (Yes or No)	Content Questions from the Standards Independent Experts Report Q1 (Yes or No) Is the content of the requirement technically correct, including identifying who does what and when?	Q2 (Yes or No) Are the correct functional entities identified?	Q3 (Yes or No) Are the appropriate actions, for which there should be accountability, included or is there a gap?	Quality Questions from the Standards Independent Experts Report Q4 (Yes or No) Should the requirement stand alone or is it more appropriate with other standards?	Q5 (Yes or No) Is it worthy of a metric (i.e. level of performance, risk prevention) or capability and does it follow the 'KBL for'or e.g., 'sub-requirement structure'?	Q6 (Yes or No) Is it technologically neutral?	Q7 (Yes or No) Are the expectations for each function clear?	Q8 (Yes or No) Does the requirement align with the purpose?	Q9 (Yes or No) Is it a higher solution than the lowest common denominator?	Q10 (Yes or No) Is it measurable?	Q11 (Yes or No) Does it have a technical basis in engineering and operations?	Q12 (Yes or No) Is it complete and self-contained?	Q12A (Yes or No) Is the language clear and does not contain ambiguous or outdated terms ?	Q13 (Yes or No) Can it be practically implemented?	Q14 (Yes or No) Does it use consistent terminology?	Q15 (Yes or No) Is the Standard cost effective in achieving the reliability purpose or mitigating the risk identified and mitigating the risk to the BES?	Content Score 0-3	Quality Score 0-13	Comment/Rationale
BAL-003-1.1	R1	R1: Each Frequency Response Sharing Group (FRSG) or Balancing Authority that is not a member of a FRSG shall achieve an annual Frequency Response Measure (FRM) (as calculated and reported in accordance with Attachment A) that is equal to or more negative than its Frequency Response Obligation (FRO) to ensure that sufficient Frequency Response is maintained by each FRSG and Balancing Authority to support Interconnection Frequency Response equal to or more negative than the Interconnection Frequency Response Obligation. [Risk Factor: High][Time Horizon: Real-time Operations].	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
BAL-003-1.1	R2	R2: Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting shall implement the Frequency Bias Setting determined in accordance with Attachment A, or a documented local FRO annually filed with the ERO, on or before the date specified by the implementation period specified by the ERO and shall use this Frequency Bias Setting until directed to change by the ERO. [Risk Factor:Medium][Time Horizon: Operations Planning]	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
BAL-003-1.1	R3	R3: Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and is utilizing a variable Frequency Bias Setting shall implement a variable Frequency Bias Setting that is: [Risk Factor: Medium] [Time Horizon: Operations Planning] R3.1: Less than zero at all times, and R3.2: Equal to or more negative than its Frequency Response Obligation when frequency varies from 60 Hz by more than +/- 0.036 Hz.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
BAL-003-1.1	R4	R4: Each Balancing Authority that is performing Overlap Regulation Service shall modify its Frequency Bias Setting in its ACE calculation, in order to represent the Frequency Bias Setting for the combined Balancing Authority Area, to be equivalent to either: [Risk Factor: Medium][Time Horizon: Operations Planning] • The sum of the Frequency Bias Settings as shown on FRS Form 1 and FRS Form 2 for the participating Balancing Authorities as validated by the ERO, or • The Frequency Bias Setting shown on FRS Form 1 and FRS Form 2 for the entirety of the participating Balancing Authorities' Areas.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
COM-001-2.1	R1	R1: Each Reliability Coordinator shall have Interpersonal Communication capability with the following entities (unless the Reliability Coordinator detects a failure of its Interpersonal Communication capability in which case Requirement R10 shall apply): [Violation Risk Factor: High] [Time Horizon: Real-time Operations] R1.1.: All Transmission Operators and Balancing Authorities within its Reliability Coordinator Area. R1.2.: Each adjacent Reliability Coordinator within the same Interconnection.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
COM-001-2.1	R2	R2: Each Reliability Coordinator shall designate an Alternative Interpersonal Communication capability with the following entities: [Violation Risk Factor: High][Time Horizon: Real-time Operations] R2.1.: All Transmission Operators and Balancing Authorities within its Reliability Coordinator Area. R2.2.: Each adjacent Reliability Coordinator within the same Interconnection.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
COM-001-2.1	R3	R3: Each Transmission Operator shall have Interpersonal Communication capability with the following entities (unless the Transmission Operator detects a failure of its Interpersonal Communication capability in which case Requirement R10 shall apply): [Violation Risk Factor: High] [Time Horizon: Real-time Operations] R3.1.: Its Reliability Coordinator. R3.2.: Each Balancing Authority within its Transmission Operator Area. R3.3.: Each Distribution Provider within its Transmission Operator Area. R3.4.: Each Generator Operator within its Transmission Operator Area. R3.5.: Each adjacent Transmission Operator synchronously connected. R3.6.: Each adjacent Transmission Operator asynchronously connected.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
COM-001-2.1	R4	R4: Each Transmission Operator shall designate an Alternative Interpersonal Communication capability with the following entities: [Violation Risk Factor: High] [Time Horizon: Real-time Operations] R4.1.: Its Reliability Coordinator. R4.2.: Each Balancing Authority within its Transmission Operator Area. R4.3.: Each adjacent Transmission Operator synchronously connected. R4.4.: Each adjacent Transmission Operator asynchronously connected.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
COM-001-2.1	R5	R5: Each Balancing Authority shall have Interpersonal Communication capability with the following entities (unless the Balancing Authority detects a failure of its Interpersonal Communication capability in which case Requirement R10 shall apply): [Violation Risk Factor: High] [Time Horizon: Real-time Operations] R5.1.: Its Reliability Coordinator. R5.2.: Each Transmission Operator that operates Facilities within its Balancing Authority Area. R5.3.: Each Distribution Provider within its Balancing Authority Area. R5.4.: Each Generator Operator that operates Facilities within its Balancing Authority Area. R5.5.: Each Adjacent Balancing Authority.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
COM-001-2.1	R6	R6: Each Balancing Authority shall designate an Alternative Interpersonal Communication capability with the following entities: [Violation Risk Factor: High] [Time Horizon: Real-time Operations] R6.1.: Its Reliability Coordinator. R6.2.: Each Transmission Operator that operates Facilities within its Balancing Authority Area. R6.3.: Each Adjacent Balancing Authority.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
COM-001-2.1	R7	R7: Each Distribution Provider shall have Interpersonal Communication capability with the following entities (unless the Distribution Provider detects a failure of its Interpersonal Communication capability in which case Requirement R10 shall apply): [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations] R7.1.: Its Balancing Authority. R7.2.: Its Transmission Operator.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
COM-001-2.1	R8	R8: Each Generator Operator shall have Interpersonal Communication capability with the following entities (unless the Generator Operator detects a failure of its Interpersonal Communication capability in which case Requirement R10 shall apply): [Violation Risk Factor: High] [Time Horizon: Real-time Operations]. R8.1.: Its Balancing Authority. R8.2.: Its Transmission Operator.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
COM-001-2.1	R9	R9: Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall test its Interpersonal Communication capability required by R1, R2, R3, R4, R5, R6, R7, and R8. If the test is unsuccessful, the responsible entity shall initiate action to repair or designate a replacement Alternative Interpersonal Communication capability within 2 hours. [Violation Risk Factor: Medium][Time Horizon: Real-time Operations, Same-day Operations]	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
COM-001-2.1	R10	R10: Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall notify entities as identified in Requirements R1, R3, and R5, respectively within 60 minutes of the detection of a failure of its Interpersonal Communication capability that lasts 30 minutes or longer. [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	For consistency with VAR-002, should notification be made immediately of any failure of communication lasting greater than 30 minutes?
COM-001-2.1	R11	R11: Each Distribution Provider and Generator Operator that detects a failure of its Interpersonal Communication capability shall consult each entity affected by the failure, as identified in Requirement R7 for a Distribution Provider or Requirement R8 for a Generator Operator, to determine a mutually agreeable action for the restoration of its Interpersonal Communication capability. [Violation Risk Factor: Medium][Time Horizon: Real-time Operations]	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	For consistency with VAR-002, should notification be made immediately of any failure of communication lasting greater than 30 minutes?
COM-002-4	R1	R1: Each Balancing Authority, Reliability Coordinator, and Transmission Operator shall have communications (voice and data, redundant and diverse) facilities to issue and receive Operating Instructions. The protocols shall, at a minimum: [Violation Risk Factor: Low][Time Horizon: Long-term Planning] R1.1.: Require its operating personnel that issue and receive oral or written Operating Instruction to use the English language, unless agreed to otherwise. An alternate language may be used for internal operations. R1.2.: Require its operating personnel that issue an oral two-party, person-to-person Operating Instruction to take one of the following actions: • Confirm the receiver's response if the repeated information is correct. • Reissue the Operating Instruction if the repeated information is incorrect or if requested by the receiver. • Take an alternative action if a response is not received or if the Operating Instruction was not understood by the receiver. R1.3.: Require its operating personnel that receive an oral two-party, person-to-person Operating Instruction to take one of the following actions: • Repeat, not necessarily verbatim, the Operating Instruction and receive confirmation from the issuer that the response was correct, or • Request that the issuer reissue the Operating Instruction. R1.4.: Require its operating personnel that issue a written or oral single-party to multiple-party burst Operating Instruction to confirm or verify that the Operating Instruction was received by at least one receiver of the Operating Instruction. R1.5.: Specify the instances that require time identification when issuing an oral or written Operating Instruction and the format for that time identification. R1.6.: Specify the facilities where the Transmission Interface Elements and Transmission Interface Facilities which issuing an oral or written Operating Instruction	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
COM-002-4	R2	R2: Each Balancing Authority, Reliability Coordinator, and Transmission Operator shall conduct initial training for each of its operating personnel responsible for the Realtime operation of the interconnected Bulk Electric System on the documented communications protocols developed in Requirement R1 prior to the individual operator's being assigned operating duties. [Violation Risk Factor: Low] [Time Horizon: Long-term Planning]	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	Does verifying initial training for well-seasoned personnel create challenges?
COM-002-4	R3	R3: Each Distribution Provider and Generator Operator shall conduct initial training for each of its operating personnel who can receive an oral two-party, person-to-person Operating Instruction prior to that individual operator receiving an oral two-party, person-to-person Operating Instruction to either: [Violation Risk Factor: Low][Time Horizon: Long-term Planning] • Repeat, not necessarily verbatim, the Operating Instruction and receive confirmation from the issuer that the response was correct, or • Request that the issuer reissue the Operating Instruction.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	Does verifying initial training for well-seasoned personnel create challenges?
COM-002-4	R4	R4: Each Balancing Authority, Reliability Coordinator, and Transmission Operator shall at least once every twelve (12) calendar months: [Violation Risk Factor:Medium][Time Horizon:Operations Planning] R4.1.: Assess adherence to the documented communications protocols in Requirement R1 by its operating personnel that issue and receive Operating Instructions, provide feedback to those operating personnel and take corrective action, as deemed appropriate by the entity, to address deviations from the documented protocols. R4.2.: Assess the effectiveness of its documented communications protocols in Requirement R1 for its operating personnel that issue and receive Operating Instructions and modify its documented communication protocols, as necessary.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
COM-002-4	R5	R5: Each Balancing Authority, Reliability Coordinator, and Transmission Operator that issues an oral two-party, person-to-person Operating Instruction during an Emergency, excluding written or oral single-party to multiple-party burst Operating Instructions, shall either: [Violation Risk Factor: High][Time Horizon: Real-time Operations] • Confirm the receiver's response if the repeated information is correct (in accordance with Requirement R6). • Reissue the Operating Instruction if the repeated information is incorrect or if requested by the receiver, or • Take an alternative action if a response is not received or if the Operating Instruction was not understood by the receiver.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	No	YES	YES	YES	YES	YES	YES	3	13	
COM-002-4	R6	R6: Each Balancing Authority, Distribution Provider, Generator Operator, and Transmission Operator that receives an oral two-party, person-to-person Operating Instruction during an Emergency, excluding written or oral single-party to multiple-party burst Operating Instructions, shall either: [Violation Risk Factor: High][Time Horizon: Real-time Operations] • Repeat, not necessarily verbatim, the Operating Instruction and receive confirmation from the issuer that the response was correct, or • Request that the issuer reissue the Operating Instruction.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
COM-002-4	R7	R7: Each Balancing Authority, Distribution Provider, and Transmission Operator that issues a written or oral single-party to multiple-party burst Operating Instruction during an Emergency shall confirm or verify that the Operating Instruction was received by at least one receiver of the Operating Instruction. [Violation Risk Factor:High][Time Horizon: Real-time Operations]	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	No	YES	YES	YES	YES	YES	YES	3	13	
FAC-001-2	R1	R1: Each Transmission Owner shall document Facility interconnection requirements, update them as needed, and make them available upon request. Each Transmission Owner's Facility interconnection requirements shall address interconnection requirements for: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] R1.1.: Generation Facilities, and R1.2.: transmission Facilities, and R1.3.: end-user Facilities.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
FAC-001-2	R2	R2: Each applicable Generator Owner shall document Facility interconnection requirements and make them available upon request within 45 calendar days of full execution of an interconnection agreement or a modification to existing interconnection agreement to a Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system. [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
FAC-001-2	R3	R3: Each Transmission Owner shall address the following items in its Facility interconnection requirements: [Violation Risk Factor: Lower] [Time Horizon: Long-Term Planning] R3.1.: Procedures for coordinated joint studies of new or materially modified existing interconnections and their impacts on affected system(s). R3.2.: Procedures for notifying those responsible for the reliability of affected system(s) of new or materially modified existing interconnections.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	No	YES	YES	YES	YES	YES	YES	3	13	
FAC-001-2	R4	R4: Each applicable Generator Owner shall address the following items in its Facility interconnection requirements: [Violation Risk Factor: Lower] [Time Horizon: Long-Term Planning] R4.1.: Procedures for coordinated joint studies of new interconnections and their impacts on affected system(s). R4.2.: Procedures for notifying those responsible for the reliability of affected system(s) of new interconnections.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
FAC-002-2	R1	R1: Each Transmission Planner and each Planning Coordinator shall study the reliability impact of: (i) interconnecting new generation, transmission, or electricity end-user Facilities and (ii) materially modifying existing interconnections of generation, transmission, or electricity end-user Facilities. The following shall be studied: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] R1.1.: The reliability impact of the new interconnection, or materially modified existing interconnection, on affected system(s). R1.2.: Adherence to applicable NERC Reliability Standards, regional and Transmission Planner criteria, and applicable Nuclear Plant Interface Requirements (NPIRs). R1.3.: Steady-state, short-circuit, and dynamics studies, as necessary, to evaluate system performance under both normal and contingency conditions; and R1.4.: Study assumptions, system performance, alternatives considered, and coordinated recommendations. While these studies may be performed independently, the results shall be evaluated and coordinated by the entities involved.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
FAC-002-2	R2	R2: Each Generator Owner seeking to interconnect new generation Facilities, or to materially modify existing interconnections of generation Facilities, shall coordinate and cooperate on studies with its Transmission Planner or Planning Coordinator, including but not limited to the provision of data as described in R1, Parts 1.1-1.4. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
FAC-002-2	R3	R3: Each Transmission Owner, each Distribution Provider, and each Load-Serving Entity seeking to interconnect new transmission Facilities or electricity end-user Facilities, or to materially modify existing interconnections of transmission Facilities or electricity end-user Facilities, shall coordinate and cooperate on studies with its Transmission Planner or Planning Coordinator, including but not limited to the provision of data as described in R1, Parts 1.1-1.4. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
FAC-002-2	R4	R4: Each Transmission Owner shall coordinate and cooperate with its Transmission Planner or Planning Coordinator on studies regarding requested new or materially modified interconnections to its Facilities, including but not limited to the provision of data as described in R1, Parts 1.1-1.4. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	No	YES	YES	YES	YES	YES	YES	3	13	
FAC-002-2	R5	R5: Each applicable Generator Owner shall coordinate and cooperate with its Transmission Planner or Planning Coordinator on studies regarding requested interconnections to its Facilities, including but not limited to the provision of data as described in R1, Parts 1.1-1.4. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
IRO-009-2	R1	R1: For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability Coordinator shall have one or more Operating Processes, Procedures, or Plans that identify actions the Reliability Coordinator shall take or actions the Reliability Coordinator shall direct others to take (up to and including Emergency procedures): [Violation Risk Factor: High] [Time Horizon: Operations Planning or Same-Day Operations] R1.1.: That can be implemented in time to prevent the identified IROL exceedance. R1.2.: To mitigate the magnitude and duration of an IROL exceedance such that the IROL exceedance is relieved within the IROL's T_V.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	Does it adequately cover the right entities; e.g., should it include Adjacent RC, and perhaps Transmission Operator?
IRO-009-2	R2	R2: Each Reliability Coordinator shall initiate one or more Operating Processes, Procedures, or Plans (not limited to the Operating Processes, Procedures, or Plans developed for Requirement R1) that are intended to prevent an IROL exceedance, as identified in the Reliability Coordinator's Real-time monitoring or Real-time Assessment. [Violation Risk Factor: High] [Time Horizon: Real-time Operations]	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	Does it adequately cover the right entities; e.g., should it include Adjacent RC, and perhaps Transmission Operator?
IRO-009-2	R3	R3: Each Reliability Coordinator shall act or direct others to act so that the magnitude and duration of an IROL exceedance is mitigated within the IROL's T_V, as identified in the Reliability Coordinator's Real-time monitoring or Real-time Assessment. [ViolationRisk Factor: High] [Time Horizon: Real-time Operations]	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	Does it adequately cover the right entities; e.g., should it include Adjacent RC, and perhaps Transmission Operator?
IRO-009-2	R4	R4: Each Reliability Coordinator shall operate to the most limiting IROL and T_V in instances where there is a difference in an IROL or its T_V between Reliability Coordinators that are responsible for that Facility (or group of Facilities). [Violation Risk Factor: High] [Time Horizon: Real-time Operations]	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	Does it adequately cover the right entities; e.g., should it include Adjacent RC, and perhaps Transmission Operator?
MOD-032-1	R1	R1:Each Planning Coordinator and each of its Transmission Planners shall jointly develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for the Planning Coordinator's planning area that include: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] R1.1.: The data listed in Attachment 1. R1.2.: Specifications of the following items consistent with procedures for building the interconnection-wide case(s): R1.2.1: Data formats; R1.2.2.: Level of detail to which equipment shall be modeled; R1.2.3.: Case types or scenarios to be modeled; and R1.2.4.: A schedule for submission of data at least once every 13 calendar months. R1.3.: Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those entities responsible for providing the data.	YES	YES	NO	YES	No	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	2	11	LSE is no longer in Registry.
MOD-032-1	R2	R2: Each Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. [Violation Risk Factor: Medium] [Time Horizon:Long-term Planning]	YES	YES	NO	YES	NO	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	2	11	LSE is no longer in Registry.
MOD-032-1	R3	R3: Upon receipt of written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2, including the technical basis or reason for the technical concerns, each notified Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider shall provide to the notifying Planning Coordinator or Transmission Planner as follows: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] R3.1.: Provide either updated data or an explanation with a technical basis for maintaining the current data. R3.2.: Provide the response within 90 calendar days of receipt, unless a longer time period is agreed upon by the notifying Planning Coordinator or Transmission Planner.	YES	YES	NO	YES	NO	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	2	11	LSE is no longer in Registry.
MOD-032-1	R4	R4: Each Planning Coordinator shall make available models for its planning area reflecting data provided to it under Requirement R2 to the Electric Reliability Organization (ERO) or its designee to support creation of the interconnection-wide case(s) that includes the Planning Coordinator's planning area. [Violation Risk Factor: Medium] [TimeHorizon: Long-term Planning]	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
TPL-001-4	R1	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] R1.1.: Models shall represent: R1.1.1.: Existing Facilities R1.1.2.: Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months. R1.1.3.: New planned Facilities and changes to existing Facilities R1.1.4.: Real and reactive Load forecasts R1.1.5.: Known commitments for firm Transmission Service and Interchange R1.1.6.: Resources (supply or demand side) required for Load	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	Should models capture adjacent Transmission Planner area?
TPL-001-4	R2	R2: Each Transmission Planner and Planning Coordinator shall perform an annual Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies, as allowed in Requirement R2, Part 2.4; document assumptions and document summarized results of the steady-state analyses, short circuit analysis, and Stability analyses. [Violation Risk Factor: High] [Time Horizon: Long-term Planning] R2.1.: 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 2.4. Qualifying studies need to include the following conditions: R2.1.1.: System Peak Load for one of the five years and for year five. R2.1.2.: System Off-Peak Load for one of the five years. R2.1.3.: P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.2.2, under those System peak or Off-Peak conditions when known outages are scheduled. R2.1.4.: 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 base assumptions used in the models listed in Requirement R1. 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 demonstrates 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.•Uncontrollable Loads and generation. • Duration or timing of known Transmission outages. R2.1.5.: When an entity's spare equipment strategy could result in the unavailability of	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	Should adjacent system be monitored for reliability issues and model outages in adjacent planning area?
TPL-001-4	R3	R3: 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] R3.1.: 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. R3.2.: 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. R3.3.: Contingency analysis for Requirement R3, Parts 3.1 & 3.2 shall: R3.3.1.: 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 analysis shall include the impact of subsequent: R3.3.2.: Tripping of Transmission elements where relay loadability limits are exceeded. R3.3.2: 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, such as generator voltage regulators, load tap changing transformers, and switched capacitors and inductors. R3.4.: 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.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	Should contingencies from the adjacent planning models be included?
TPL-001-4	R4	R4: 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] R4.1.: 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. R4.1.1.: 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. R4.1.2.: 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. R4.1.3.: For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner. R4.2.: 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. R4.3.: Contingency analysis for Requirement R4, Parts 4.5 and 4.2 shall : R4.3.1.: 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 analysis shall include the impact of subsequent: R4.3.1.1.: Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a fault where high speed reclosing is utilized. R4.3.2.2.: Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed minimum generator voltage ride through capability. Include in the assessment any assumptions made.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	Should contingencies from the adjacent planning models be included?
TPL-001-4	R5	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]	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	No	YES	YES	YES	YES	YES	YES	3	13	Should most limiting criteria be included? Reference for this would be Requirement R1, Part 1.1.2 of FAC-001-2.

TPL-001-4	R6	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]	YES		YES		NO		YES		YES		YES		YES		YES		YES		YES		YES		YES		YES	3		Should most limiting criteria be included? Reference for this would be Requirement R1, Part 1.1.2 of FAC-002-2.
TPL-001-4	R7	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]	YES		YES		NO		YES		YES		YES		YES		YES		YES		YES		YES		YES		YES	3		Should most limiting criteria be included? Reference for this would be Requirement R1, Part 1.1.2 of FAC-002-2.
TPL-001-4	R8	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 the receiving entity shall have a reliability need if it cannot duplicate, using publicly available models, the results of the Planning Assessment. The receiving entity may submit a written request for the information within 30 days of such a request. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] R8.1: 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.	YES		YES		NO		YES		YES		YES		YES		YES		YES		YES		YES		YES		YES	3		Should most limiting criteria be included? Reference for this would be Requirement R1, Part 1.1.2 of FAC-002-2. Should third-party impact be identified and followed by coordination of study results?

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2017-04 Periodic Review of Interchange Scheduling and Coordination Standards

Periodic Review Team Nomination Period Open through May 15, 2017

Now Available

Nominations are being sought for periodic review team members through **8 p.m. Eastern, Monday, May 15, 2017**.

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 Drafting Team Vacancies page and the project page.

Previous drafting or periodic review team experience is beneficial, but not required. See the project page and unofficial nomination form for additional information.

Next Steps

The Standards Committee is expected to appoint members to the team July 2017. Nominees will be notified shortly after they have been appointed**.**

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

For more information or assistance, contact Standards Developer, Laura Anderson (via email) or at (404) 446-9671.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Standard Authorization Request (SAR) Form

Complete and please email this form, with attachment(s) to: sarcomm@nerc.net

The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

Requested information			
SAR Title:	Standards Alignment with Registration		
Date Submitted:			
SAR Requester			
Name:	NERC Standards Staff		
Organization:	NERC		
Telephone:		Email:	
SAR Type (Check as many as apply)			
☐ New Standard ☒ Revision to Existing Standard ☐ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☒ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☐ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☐ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
This project will align the standards that are impacted by the Risk-Based Registration (RBR) initiative.			
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):			
This project aligns Standards with the FERC-approved RBR initiative.			
Project Scope (Define the parameters of the proposed project):			
This project will review and align standards impacted by the RBR initiative.			
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[1] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.* research paper) to guide development of the Standard or definition):			
This project will formally address any remaining edits to the standards that are needed to align the existing standards with the RBR initiatives. The edits include updates to the BAL, CIP, FAC, INT, IRO, MOD, NUC, and TOP family of standards to remove the references to Purchasing-Selling Entities (PSEs) and Interchange Authorities (IAs); references to the Load-Serving Entity (LSEs) will be replaced by either the Distribution Provider (DP) or the Balancing Authority (BA). Additionally, PRC-005 will replace the distribution provider with the Underfrequency Load Shedding (UFLS)-only DPs.			

[1] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.

Requested information
The clean-up effort of the standards can be categorized into the following: 1. Modifications to existing standards where the removal of the retired function may need replacement by another function. Specifically, Reliability Standard MOD-032-1 specifies certain data from LSEs that may need to be provided by other functional entities going forward. A SAR has been submitted to modify the MOD standards, and it would be posted with the Alignment with Registration SAR. 2. Modifications where the applicable entity and references may be removed. These updates may be able to follow a similar process to the Paragraph 81 initiatives where standards are redlined and posted for industry comment and ballot. A majority of the edits would simply remove deregistered functional entities and their applicable requirements/references. The impacted standards include the BAL, CIP, IRO, and TOP family of standards. Additionally PRC-005 will be updated to replace distribution providers with the more-limited UFLS-only DP to align with the post-RBR registration impacts. 3. Initiatives that can address RBR updates through the periodic review process. This would include the INT-004 and NUC-001 standards. In other words, rather than making the revisions immediately, this information would be provided to the periodic review teams currently reviewing INT-004 and NUC-001 so that any changes resulting from those periodic reviews, if any, may be proposed at the same time after completion of each periodic review.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
No additional costs outside of the time and resources needed to serve on the SAR and SC team.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g*. Dispersed Generation Resources):
NA
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g*. Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Since LSE is being replaced by either a Distribution Provider or Balancing Authority for the standards that need to be updated, those entities will like be best suited for the MOD and PRC updates.
Do you know of any consensus building activities[2] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
NA
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so which standard(s) or project number(s)?
A separate SAR on the MOD standards was recently received that would be addressed by this project.
Are there alternatives (e.g. guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.

[2] Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

Reliability Principles	
Does this proposed standard development project support at least one of the following Reliability Principles (Reliability Interface Principles)? Please check all those that apply.	
☐	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☐	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

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

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
e.g. NPCC	

For Use by NERC Only

SAR Status Tracking (Check off as appropriate)	
☐ Draft SAR reviewed by NERC Staff ☐ Draft SAR presented to SC for acceptance ☐ DRAFT SAR approved for posting by the SC	☐ Final SAR endorsed by the SC ☐ SAR assigned a Standards Project by NERC ☐ SAR denied or proposed as Guidance document

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	January X, 2017	Standards Information Staff	Revised

Standard Authorization Request (SAR) Form

Complete and please email this form, with attachment(s) to: sarcomm@nerc.com

The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

Requested information			
SAR Title:	MOD-032-1 Entity Change Due to Rules of Procedure Modification		
Date Submitted:	06/15/2017		
SAR Requester			
Name:	Rich Hydzik on behalf of NERC Essential Reliability Resources Work Group		
Organization:	NERC ERSWG / Avista		
Telephone:	509 495 4005	Email:	rich.hydzik@avistacorp.com
SAR Type (Check as many as apply)			
☐ New Standard ■ Revision to Existing Standard ☐ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☐ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☐ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ■ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
This project is intended to facilitate accurate data collection to facilitate modeling of the Distribution Provider's (DP) facilities.			
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):			
Accurate modeling of distribution facilities is required to ensure that power system models accurately reflect the bulk power system (BPS) performance. These models are used in system analysis for planning purposes and construction of a reliable BPS. These models are in used in system analysis for operating purposes to ensure a reliable BPS in both short term, day-ahead, and real-time operational planning analyses.			
Project Scope (Define the parameters of the proposed project):			
This project proposes removing the Load Serving Entity (LSE) from the Applicability Section (4.1.3) and replacing LSE with Distribution Provider (DP) as the applicable entity for Section 4.1.3. LSE is no longer considered a reliability entity due to a change in the NERC Rules of Procedure. The DP is defined as "provides and operates the 'wires' between the transmission system and the end use customer." The DP is the applicable entity to provide data for power system modeling and analysis for distribution systems. Attachment 1 should be modified by replacing the applicable entity LSE with DP.			

Requested information
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[1]which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.* research paper) to guide development of the Standard or definition):
This project proposes removing the Load Serving Entity (LSE) from the Applicability Section (4.1.3) and replacing LSE with Distribution Provider (DP) as the applicable entity for Section 4.1.3. LSE is no longer considered a reliability entity due to a change in the NERC Rules of Procedure. The DP is defined as "provides and operates the 'wires' between the transmission system and the end use customer." The DP is the applicable entity to provide data for power system modeling and analysis for distribution systems.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
Cost impacts should be minimal. Planning Coordinator and Transmission Planners are required to collect modeling data under MOD-032-1. In the past, Planning Coordinator and Transmission Planners collected from LSE's. This entity would be the DP under the proposed change.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g*. Dispersed Generation Resources):
None
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g*. Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Planning Coordinator Transmission Planner Transmission Operator Distribution Provider
Do you know of any consensus building activities[2] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
No
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so which standard(s) or project number(s)?
No
Are there alternatives (e.g. guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives. None identified

Reliability Principles	
Does this proposed standard development project support at least one of the following Reliability Principles (Reliability Interface Principles)? Please check all those that apply.	
■	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

[1] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.

[2] Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

Reliability Principles	
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
■	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

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

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
e.g. NPCC	

For Use by NERC Only

SAR Status Tracking (Check off as appropriate)	
☐ Draft SAR reviewed by NERC Staff ☐ Draft SAR presented to SC for acceptance ☐ DRAFT SAR approved for posting by the SC	☐ Final SAR endorsed by the SC ☐ SAR assigned a Standards Project by NERC ☐ SAR denied or proposed as Guidance document

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	January X, 2017	Standards Information Staff	Revised

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
1	Project 2007-24	Request for Interpretation - TPL-002 and TPL-003 - Ameren_in	Initial Ballot	4/25/2008	5/7/2008	Quorum: 82.61% Approval: 80.73%			
2	Project 2007-26	Request for Interpretation - TPL-002 and TPL-003 - MISO_in	Initial Ballot	4/25/2008	5/7/2008	Quorum: 83.01% Approval: 79.89%			
3	Project 2008-04	FAC-010_FAC-011_FAC-014_Order_705_in	Initial Ballot	6/2/2008	6/11/2008	Quorum: 88.83% Approval: 95.43%			
4	Project 2008-07	Interpretation Request - EOP-002 - Brookfield_in	Initial Ballot	6/2/2008	6/11/2008	Quorum: 89.67% Approval: 76.47%			
5	Project 2008-04	FAC-010_FAC-011_FAC-014_Order_705_rc	Recirculation Ballot	6/13/2008	6/22/2008	Quorum: 89.36% Approval: 95.21%			
6	Project 2008-09	Request for Interpretation - EOP-001-0 - RECM_in	Initial Ballot	6/19/2008	7/2/2008	Quorum: 84.82% Approval: 85.79%			
7	Project 2007-24	Request for Interpretation - TPL-002 and TPL-003 - Ameren_rc	Recirculation Ballot	6/27/2008	7/7/2008	Quorum: 83.57% Approval: 79.13%			
8	Project 2007-26	Request for Interpretation - TPL-002 and TPL-003 - MISO_rc	Recirculation Ballot	6/27/2008	7/7/2008	Quorum: 83.98% Approval: 78.31%			
9	Pre-2006	IROL Standard - IRO-010_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 92.71% Approval: 88.40%			
10	Pre-2006	IROL Standard - IRO-009_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 92.63% Approval: 89.44%			
11	Pre-2006	IROL Standard - IRO-008_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 92.67% Approval: 91.71%			
12	Project 2006-07	ATC et al Standard - MOD-030_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 94.37% Approval: 56.56%			
13	Project 2006-07	ATC et al Standard - MOD-029_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 94.67% Approval: 92.62%			
14	Project 2006-07	ATC et al Standard - MOD-028_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 94.64% Approval: 79.47%			
15	Project 2006-07	ATC et al Standard - MOD-008_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 94.27% Approval: 80.44%			
16	Project 2006-07	ATC et al Standard - MOD-001_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 94.02% Approval: 75.97%			
17	Project 2008-10	Request for Interpretation - CIP-006-1 - Progress Energy_in	Initial Ballot	8/7/2008	8/16/2008	Quorum: 88.18% Approval: 21.52%			
18	Pre-2006	IROL Standard - IRO-008_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 93.72% Approval: 89.49%			
19	Pre-2006	IROL Standard - IRO-009_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 93.68% Approval: 86.53%			
20	Pre-2006	IROL Standard - IRO-010_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 93.75% Approval: 85.95%			
21	Project 2006-07	ATC et al Standards - MOD-001_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 94.87% Approval: 76.83%			
22	Project 2006-07	ATC et al Standard - MOD-008_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 95.15% Approval: 81.49%			
23	Project 2006-07	ATC et al Standard - MOD-028_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 95.54% Approval: 79.34%			
24	Project 2006-07	ATC et al Standard - MOD-029_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 95.56% Approval: 92.24%			
25	Project 2006-07	ATC et al Standard - MOD-030_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 95.24% Approval: 74.26%			
26	Project 2008-11	Request for Interpretation - VAR-002-1 - ICF Consulting_in	Initial Ballot	9/9/2008	9/17/2008	Quorum: 85.78% Approval: 90.37%			
27	Project 2006-07	ATC et al Standard - MOD-004_in	Initial Ballot	9/11/2008	9/21/2008	Quorum: 79.26% Approval: 66.29%			
28	Project 2007-14	Permanent Changes to CI Timing Tables_in	Initial Ballot	9/12/2008	9/22/2008	Quorum: 79.74% Approval: 100.00%			
29	Project 2008-07	Request for Interpretation - Brookfield Power - EOP-002_rb	Re-ballot	10/6/2008	10/24/2008	Quorum: 82.61% Approval: 74.67%			
30	Project 2008-13	Request for Interpretation - TOP-002-2 - Orlando Utilities Commission_in	Initial Ballot	10/21/2008	10/30/2008	Quorum: 83.33% Approval: 96.94%			
31	Project 2006-01	Project 2006-01 - PER-005-1_in	Initial Ballot	10/27/2008	11/5/2008	Quorum: 90.13% Approval: 82.47%			
32	Project 2006-09	Project 2006-09 - FAC-008-2 - Facility Ratings_in	Initial Ballot	10/27/2008	11/5/2008	Quorum: 89.13% Approval: 70.01%			
33	Project 2006-07	ATC et al Standard - MOD-004_rc	Recirculation Ballot	10/28/2008	11/6/2008	Quorum: 91.49% Approval: 83.71%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
34	Project 2006-07	Project 2006-07 (ATC) MOD-030-2_in	Initial Ballot	12/1/2008	12/10/2008	Quorum: 83.77% Approval: 86.51%			
35	Project 2006-09	Project 2006-09 - FAC-008-2 - Facility Ratings_rc	Recirculation Ballot	12/10/2008	12/19/2008	Quorum: 93.04% Approval: 57.37%			
36	Project 2008-13	Request for Interpretation - TOP-002-2 - Orlando Utilities Commission_rc	Recirculation Ballot	12/10/2008	12/19/2008	Quorum: 87.62% Approval: 97.47%			
37	Project 2006-01	Project 2006-01 - PER-005-1_rc	Recirculation Ballot	12/12/2008	12/22/2008	Quorum: 91.48% Approval: 80.63%			
38	Project 2008-15	Request for Interpretation - CIP-006-1a - US Army COE_in	Initial Ballot	1/5/2009	1/14/2009	Quorum: 91.15% Approval: 97.39%			
39	Project 2008-16	TOP-004-2 VSL Revisions_in	Initial Ballot	1/5/2009	1/14/2009	Quorum: 91.20% Approval: 93.93%			
40	Project 2008-11	Request for Interpretation - VAR-002-1 - ICF Consulting_rc	Recirculation Ballot	1/6/2009	1/15/2009	Quorum: 91.47% Approval: 91.21%			
41	Project 2006-07	Project 2006-07 (ATC) MOD-030-2_rc	Recirculation Ballot	1/20/2009	1/29/2009	Quorum: 85.86% Approval: 86.39%			
42	Project 2008-16	TOP-004-2 VSL Revisions_rc	Recirculation Ballot	1/28/2009	2/6/2009	Quorum: 92.59% Approval: 96.06%			
43	Project 2008-15	Request for Interpretation - CIP-006-1a - US Army COE_rc	Recirculation Ballot	2/6/2009	2/16/2009	Quorum: 93.81% Approval: 99.12%			
44	Project 2008-09	Interpretation Request - EOP-001 - R1 - RECM_in	Initial Ballot	2/27/2009	3/9/2009	Quorum: 89.67% Approval: 89.03%			
45	Project 2008-18	Project 2008-18 Interpretation-Manitoba Hydro_in	Initial Ballot	3/19/2009	3/30/2009	Quorum: 89.78% Approval: 92.62%			
46	Project 2008-06	Project 2008-06: CIP-002-1-CIP-009-1 Revisions_in	Initial Ballot	4/1/2009	4/10/2009	Quorum: 91.90% Approval: 84.06%			
47	Project 2009-10	Project 2009-10 Interpretation - CMPWG - PRC-005-1 R1_in	Initial Ballot	4/8/2009	4/17/2009	Quorum: 92.70% Approval: 92.71%			
48	Project 2006-03	Project 2006-03 EOP-001_EOP-005_EOP-006 System Restoration and Blackstart_in	Initial Ballot	4/14/2009	4/23/2009	Quorum: 89.81% Approval: 76.63%			
49	Project 2008-06	Project 2008-06: CIP-002-1-CIP-009-1 Revisions_rc	Recirculation Ballot	4/17/2009	4/27/2009	Quorum: 94.37% Approval: 88.32%			
50	Project 2008-18	Project 2008-18 Interpretation-Manitoba Hydro_rc	Recirculation Ballot	4/17/2009	4/27/2009	Quorum: 95.56% Approval: 92.81%			
51	Project 2009-11	Project 2009-11 Interpretation WECC Reliability Coordination Subcommittee IRO-10-1_in	Initial Ballot	4/22/2009	5/1/2009	Quorum: 88.64% Approval: 84.77%			
52	Project 2006-03	Project 2006-03 EOP-001_EOP-005_EOP-006 System Restoration and Blackstart_rc	Recirculation Ballot	5/6/2009	5/18/2009	Quorum: 92.08% Approval: 75.39%			
53	Project 2009-15	Project 2009-15 Interpretation - NYISO - MOD-001-1, MOD-029-1_in	initial Ballot	5/25/2009	6/4/2009	Quorum: 85.13% Approval: 82.10%			
54	Project 2009-11	Project 2009-11 Interpretation WECC Reliability Coordination Subcommittee IRO-10-1_rc	Recirculation Ballot	5/26/2009	6/5/2009	Quorum: 90.45% Approval: 85.76%			
55	Project 2009-14	Project 2009-14 Interpretation - PacifiCorp - TPL-002-0a_in	Initial Ballot	6/1/2009	6/11/2009	Quorum: 87.10% Approval: 95.71%			
56	Project 2009-08	Project 2009-08 - Nuclear Plant Interface Coordination for Order 716_in	Initial Ballot	6/12/2009	6/22/2009	Quorum: 81.72% Approval: 94.09%			
57	Project 2008-14	Project 2008-14 VSLs for CIP-002-1 through CIP-009-1_in	Initial Ballot	6/15/2009	6/24/2009	Quorum: 87.23% Approval: 83.94%			
58	Project 2008-14	Project 2008-14 VSLs for CIP-002-1 through CIP-009-1_rc	Recirculation Ballot	7/7/2009	7/16/2009	Quorum: 92.77% Approval: 84.96%			
59	Project 2009-15	Project 2009-15 Interpretation - NYISO - MOD-001-1, MOD-029-1_rc	Recirculation Ballot	7/8/2009	7/17/2009	Quorum: 90.26% Approval: 82.25%			
60	Project 2009-08	Project 2009-08 - Nuclear Plant Interface Coordination for Order 716_rc	Recirculation Ballot	7/10/2009	7/20/2009	Quorum: 87.10% Approval: 96.94%			
61	Project 2009-10	Project 2009-10 Interpretation - CMPWG - PRC-005-1 R1_rc	Recirculation Ballot	7/24/2009	8/6/2009	Quorum: 95.26% Approval: 95.62%			
62	Project 2009-14	Project 2009-14 Interpretation - PacifiCorp - TPL-002-0a_rc	Recirculation Ballot	7/24/2009	8/6/2009	Quorum: 91.24% Approval: 98.85%			
63	Project 2007-23	Project 2007-23 TPL Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 85.71% Approval: 90.46%			
64	Project 2007-23	Project 2007-23 TOP Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 86.40% Approval: 89.14%			
65	Project 2007-23	Project 2007-23 PRC Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 86.32% Approval: 88.26%			
66	Project 2007-23	Project 2007-23 IRO Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 86.16% Approval: 90.15%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
67	Project 2007-23	Project 2007-23 INT, PER, and NUC Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 85.71% Approval: 88.63%			
68	Project 2007-23	Project 2007-23 FAC and MOD Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 86.64% Approval: 87.63%			
69	Project 2007-23	Project 2007-23 CIP, COM, and VAR Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 86.50% Approval: 85.78%			
70	Project 2007-23	Project 2007-23 BAL Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 86.28% Approval: 89.56%			
71	Project 2008-08	Project 2008-08 EOP Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 87.98% Approval: 87.31%			
72	Project 2009-17	Project 2009-17 Interpretation - Y-W Electric and Tri-State - PRC-004-1 and PRC-005-1_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 90.32% Approval: 62.15%			
73	RSDP V7	Reliability Standards Development Procedure - Version 7 - June 2009_rb	Re-ballot	7/27/2009	8/14/2009	Quorum: 84.65% Approval: 74.79%			
74	Project 2009-09	Project 2009-09 - Interpretation - Covanta Energy - CIP-001-1_in	Initial Ballot	8/6/2009	8/17/2009	Quorum: 84.68% Approval: 68.92%			
75	Project 2007-23	Project 2007-23 TPL Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 91.96% Approval: 89.28%			
76	Project 2007-23	Project 2007-23 BAL Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 92.04% Approval: 89.41%			
77	Project 2007-23	Project 2007-23 CIP, COM, and VAR Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 92.41% Approval: 84.64%			
78	Project 2007-23	Project 2007-23 FAC and MOD Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 92.67% Approval: 88.04%			
79	Project 2007-23	Project 2007-23 INT, PER, and NUC Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 92.17% Approval: 88.73%			
80	Project 2007-23	Project 2007-23 IRO Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 91.96% Approval: 90.77%			
81	Project 2007-23	Project 2007-23 PRC Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 92.31% Approval: 86.93%			
82	Project 2007-23	Project 2007-23 TOP Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 92.11% Approval: 88.26%			
83	Project 2008-08	Project 2008-08 EOP Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 92.70% Approval: 85.80%			
84	Order 706-B	Order 706-B Nuclear Implementation Plan_in	Initial Ballot	8/19/2009	8/28/2009	Quorum: 81.96% Approval: 97.37%			
85	Project 2008-07	Request for Interpretation - Brookfield Power - EOP-002_rc	Recirculation Ballot	8/20/2009	8/31/2009	Quorum: 86.96% Approval: 70.85%			
86	Project 2009-12	Project 2009-12 - Interpretation - PacifiCorp - CIP-005-1_in	Initial Ballot	8/27/2009	9/8/2009	Quorum: 84.68% Approval: 80.37%			
87	Project 2009-13	Project 2009-13 - Interpretation - PacifiCorp - CIP-006-1_in	Initial Ballot	8/27/2009	9/8/2009	Quorum: 84.92% Approval: 79.04%			
88	Project 2009-18	Project 2009-18 - Withdraw Three Midwest ISO Waivers_in	Initial Ballot	8/27/2009	9/8/2009	Quorum: 85.28% Approval: 99.62%			
89	Order 706-B	Order 706-B Nuclear Implementation Plan_rc	Recirculation Ballot	9/1/2009	9/10/2009	Quorum: 87.11% Approval: 97.18%			
90	RSDP V7	Reliability Standards Development Procedure - Version 7 - June 2009_rc	Recirculation Ballot	9/2/2009	9/14/2009	Quorum: 86.31% Approval: 76.09%			
91	Project 2008-06	Project 2008-06 Cyber Security (VRFs and VSLs for Version 2 CIP Standards)_in	Initial Ballot	9/10/2009	9/21/2009	Quorum: 87.45% Approval: 94.18%			
92	Project 2009-16	Project 2009-16 - Interpretation - WECC - CIP-007-1_in	Initial Ballot	9/9/2009	9/21/2009	Quorum: 85.31% Approval: 100.00%			
93	Project 2006-04	Project 2006-04 - Back-up Facilities - EOP-008-1_in	Initial Ballot	9/16/2009	9/28/2009	Quorum: 82.69% Approval: 72.86%			
94	Project 2009-09	Project 2009-09 - Interpretation - Covanta Energy - CIP-001-1_rc	Recirculation Ballot	9/29/2009	10/9/2009	Quorum: 89.92% Approval: 68.31%			
95	Project 2008-10	Project 2008-10 - Interpretation of CIP-006-1 Revised R1 for Progress Energy	Initial Ballot	9/30/2009	10/12/2009	Quorum: 79.92% Approval: 74.47%			
96	Project 2009-12	Project 2009-12 - Interpretation - PacifiCorp - CIP-005-1_rc	Recirculation Ballot	10/16/2009	10/26/2009	Quorum: 86.29% Approval: 83.25%			
97	Project 2008-06	Project 2008-06 Cyber Security (VRFs and VSLs for Version 2 CIP Standards)_rc	Recirculation Ballot	11/2/2009	11/12/2009	Quorum: 88.70% Approval: 94.24%			
98	Project 2008-09	Project 2008-09 - Interpretation - RECM - Revision 2_in	Initial Ballot	11/5/2009	11/16/2009	Quorum: 85.97% Approval: 98.07%			
99	Project 2009-21	Project 2009-21 - Cyber Security Ninety-day Response_in	Initial Ballot	11/20/2009	11/30/2009	Quorum: 89.58% Approval: 88.07%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
100	Project 2009-17	Project 2009-17 - Interpretation Y-W Electric and Tri-State (Revision 1)_in	Initial Ballot	11/19/2009	12/7/2009	Quorum: 85.83% Approval: 58.91%			
101	Project 2009-20	Project 2009-20 - Interpretation - BAL-003-0 - Energy Mark, Inc._in	Initial Ballot	11/20/2009	12/7/2009	Quorum: 87.11% Approval: 93.40%			
102	Project 2009-21	Project 2009-21 - Cyber Security Ninety-day Response_rc	Recirculation Ballot	12/3/2009	12/14/2009	Quorum: 93.33% Approval: 85.55%			
103	Project 2009-23	Project 2009-23 - Interpretation - CIP-004-2 - U.S. Army Corps of Engineers_in	Initial Ballot	12/1/2009	12/14/2009	Quorum: 86.13% Approval: 72.11%			
104	Project 2009-13	Project 2009-13 - Interpretation - PacifiCorp - CIP-006-1_rc	Recirculation Ballot	12/11/2009	12/23/2009	Quorum: 90.08% Approval: 78.77%			
105	Project 2009-24	Project 2009-24 - Interpretation - FMPA - EOP-005-1_in	Initial Ballot	1/5/2010	1/15/2010	Quorum: 87.68% Approval: 17.79%			
106	Project 2009-25	Project 2009-25 - Interpretation - BPA - BAL-001-01.a and BAL-002-0_in	Initial Ballot	1/5/2010	1/15/2010	Quorum: 88.00% Approval: 34.28%			
107	Project 2009-26	Project 2009-26 - Interpretation - WECC - CIP-004-1_in	Initial Ballot	1/6/2010	1/19/2010	Quorum: 84.21% Approval: 42.24%			
108	Project 2009-06	Project 2009-06 - Facility Ratings: FAC-008-2	Initial Ballot	1/12/2010	1/22/2010	Quorum: 89.16% Approval: 75.16%			
109	Project 2009-27	Project 2009-27 - Interpretation - TOP-002-2a for FMPAA_in	Initial Ballot	2/10/2010	2/22/2010	Quorum: 84.98% Approval: 90.82%			
110	Project 2009-28	Project 2009-28 - Interpretation - EOP-001-1 and EOP-001-2 for FMPP_in	Initial Ballot	2/10/2010	2/22/2010	Quorum: 87.36% Approval: 91.79%			
111	Project 2009-29	Project 2009-29 - Interpretation - TOP-002-2a for FMPP_in	Initial Ballot	2/11/2010	2/22/2010	Quorum: 84.34% Approval: 84.56%			
112	Project 2009-19	Project 2009-19 - Interpretation - BAL-002-0 Northwest Power Pool RSG_in	Initial Ballot	2/15/2010	2/26/2010	Quorum: 89.83% Approval: 48.60%			
113	Project 2009-20	Project 2009-20 - Interpretation - BAL-003-0 - Energy Mark, Inc._rc	Recirculation Ballot	2/16/2010	2/26/2010	Quorum: 92.44% Approval: 91.90%			
114	Project 2009-30	Project 2009-30 - Interpretation - PRC-001-1 for WPSC_in	Initial Ballot	2/15/2010	2/26/2010	Quorum: 89.51% Approval: 48.74%			
115	Project 2006-02	Project 2006-02 - Assess Transmission Future Needs - TPL-001-1_in	Initial Ballot	2/19/2010	3/1/2010	Quorum: 91.38% Approval: 35.36%			
116	Project 2009-31	Project 2009-31 - Interpretation - TOP-001-1 for FMPP_in	Initial Ballot	3/3/2010	3/16/2010	Quorum: 88.24% Approval: 98.27%			
117	Project 2009-06	Project 2009-06 - Facility Ratings: FAC-008-2	Recirculation Ballot	3/8/2010	3/18/2010	Quorum: 93.71% Approval: 78.15%			
118	Project 2009-32	Project 2009-32 - Interpretation - EOP-003-1 for FMPP_rb	Re-ballot	3/10/2010	3/31/2010	Quorum: 91.37% Approval: 77.66%			
119	Project 2009-23	Project 2009-23 - Interpretation - CIP-004-2 - U.S. Army Corps of Engineers (Revision 1)_in	Initial Ballot	3/29/2010	4/8/2010	Quorum: 88.52% Approval: 63.43%			
120	Project 2008-09	Project 2008-09 - Interpretation - RECM - Revision 3_in	Initial Ballot	4/15/2010	4/26/2010	Quorum: 81.97% Approval: 98.64%			
121	SPM	Standards Process Manual Revisions_in	Initial Ballot	4/19/2010	4/29/2010	Quorum: 87.82% Approval: 80.48%			
122	Project 2009-17	Project 2009-17 - Interpretation Y-W Electric and Tri-State (Revision 2)_in	Initial Ballot	4/28/2010	5/10/2010	Quorum: 83.15% Approval: 74.55%			
123	SPM	Standards Process Manual Revisions_rc	Recirculation Ballot	4/30/2010	5/10/2010	Quorum: 93.73% Approval: 86.69%			
124	Project 2010-11	Project 2010-11 SAR for TPL Table 1 Order_in	Initial Ballot	5/17/2010	5/27/2010	Quorum: 84.41% Approval: 63.75%			
125	Project 2010-09	Project 2010-09: NUC Implementation Plans for CIP Version 2 and Version 3_in	Initial Ballot	5/19/2010	6/1/2010	Quorum: 84.83% Approval: 90.83%			
126	Project 2010-09	Project 2010-09: NUC Implementation Plans for CIP Version 2 and Version 3_rc	Recirculation Ballot	6/22/2010	7/2/2010	Quorum: 89.10% Approval: 87.24%			
127	Project 2006-04	Project 2006-04 - Backup Facilities - Revision 1_in	Initial Ballot	6/23/2010	7/6/2010	Quorum: 89.05% Approval: 79.45%			
128	Project 2006-08	Project 2006-08 - Reliability Coordination - Transmission Loading Relief_in	Initial Ballot	6/23/2010	7/6/2010	Quorum: 87.04% Approval: 84.98%			
129	Project 2007-01	Project 2007-01 Underfrequency Load Shedding: PRC-006-1 and EOP-003-1	Initial Ballot	7/7/2010	7/17/2010	Quorum: 86.94% Approval: 43.13%			
130	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005-2	Initial Ballot	7/8/2010	7/17/2010	Quorum:91.12 % Approval: 22.91%			
131	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005-2	Non-binding Poll	7/8/2010	7/17/2010	Quorum: 86.00% Approval: 28.00%			
132	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: Protection System definition	Initial Ballot	7/8/2010	7/17/2010	Quorum: 87.85% Approval: 39.35%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
133	Project 2007-07	Project 2007-07 Vegetation Management: FAC-003-2	Initial Ballot	7/9/2010	7/19/2010	Quorum: 86.18% Approval: 65.93%			
134	Project 2006-04	Prokect 2006-04 - Backup Facilities - Revision 1_rc	Recirculation Ballot	7/16/2010	7/26/2010	Quorum: 93.43% Approval: 85.22%			
135	Project 2007-17	Project 2007-17 Protection System Maintenance: Protection System definition	Successive Ballot	7/23/2010	8/2/2010	Quorum: 94.70% Approval: 58.61%			
136	Project 2007-01	Project 2007-01 Underfrequency Load Shedding: PRC-006-1 and EOP-003-1	Successive Ballot	7/24/2010	8/3/2010	Quorum: 92.99% Approval: 49.61%			
137	Project 2006-08	Project 2006-08 - Reliability Coordination - Transmission Loading Relief_rc	Recirculation Ballot	8/20/2010	8/30/2010	Quorum: 88.26% Approval: 93.93%			
138	Project 2007-04	Project 2007-04 - Certifying System Operators: PER-003-1	Initial Ballot	9/14/2010	9/24/2010	Quorum: 92.73% Approval: 79.17%			
139	Project 2010-15	Project 2010-15 - Urgent Action Revisions to CIP-005-3	Initial Ballot	9/17/2010	9/27/2010	Quorum: 96.46% Approval: 21.77%			
140	Project 2007-01	Project 2007-01 Underfrequency Load Shedding: PRC-006-1 and EOP-003-1	Successive Ballot	9/24/2010	10/4/2010	Quorum: 85.71% Approval: 81.72%			
141	Project 2007-17	Project 2007-17 Protection System Maintenance: Protection System definition	Successive Ballot	10/2/2010	10/14/2010	Quorum: 84.11% Approval: 84.52%			
142	Project 2008-09	Project 2008-09 - Interpretation - RECM - Revision 3_rc	Recirculation Ballot	10/4/2010	10/14/2010	Quorum: 88.11% Approval: 99.14%			
143	Project 2009-28	Project 2009-28 - Interpretation - EOP-001-1 and EOP-001-2 for FMPP_rc	Recirculation Ballot	10/5/2010	10/15/2010	Quorum: 92.19% Approval: 94.78%			
144	Project 2009-27	Project 2009-27 - Interpretation - TOP-002-2a for FMPAA_rc	Recirculation Ballot	10/6/2010	10/16/2010	Quorum: 91.21% Approval: 93.44%			
145	Project 2007-01	Project 2007-01 Underfrequency Load Shedding: PRC-006-1 and EOP-003-1	Recirculation Ballot	10/18/2010	10/28/2010	Quorum: 89.84% Approval: 84.67%			
146	Project 2008-06	Project 2008-06 Cyber Security 706 (Version 4 CIP Standards)_in	Initial Ballot	10/20/2010	11/3/2010	Quorum: 93.66% Approval: 43.33%			
147	Project 2010-10	Project 2010-10 FAC-013-2 Planning Transfer Capability_in	Initial Ballot	10/20/2010	11/3/2010	Quorum: 88.54% Approval: 39.85%			
148	2010 SPM	2010 Standard Processes Manual (Proposed Changes)_in	Initial Ballot	10/28/2010	11/7/2010	Quorum: 81.61% Approval: 93.72%			
149	Project 2007-17	Project 2007-17 Protection System Maintenance: Protection System definition	Recirculation Ballot	11/1/2010	11/11/2010	Quorum: 89.41% Approval: 86.83%			
150	2010 SPM	2010 Standard Processes Manual (Proposed Changes)_rc	Recirculation Ballot	11/9/2010	11/13/2010	Quorum: 87.00% Approval: 92.88%			
151	Project 2009-17	Project 2009-17 - Interpretation Y-W Electric and Tri-State (Revision 2)_rc	Recirculation Ballot	11/19/2010	12/3/2010	Quorum: 87.81% Approval: 82.41%			
152	Project 2008-06	Project 2008-06 Cyber Security 706 (Version 4 CIP Standards)_sb_in	Initial Ballot	12/1/2010	12/10/2010	Quorum: 87.07% Approval: 77.06%			
153	Project 2010-15	Project 2010-15 - Expedited Action Revisions to CIP-005-3	Initial Ballot	12/2/2010	12/11/2010	Quorum: 84.46% Approval: 42.89%			
154	Project 2007-04	Project 2007-04 - Certifying System Operators: PER-003-1	Recirculation Ballot	12/2/2010	12/13/2010	Quorum: 95.50% Approval: 86.91%			
155	Project 2010-13	Project 2010-13 - Relay Loadability Order - PRC-023	Initial Ballot	12/7/2010	12/16/2010	Quorum: 88.00% Approval: 51.51%			
156	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005-2	Successive Ballot	12/10/2010	12/20/2010	Quorum: 79.88% Approval: 44.65%			
157	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005-2	Non-binding Poll	12/10/2010	12/20/2010	Quorum: 78.00% Approval: 53.00%			
158	Project 2008-06	Project 2008-06 Cyber Security 706 (Version 4 CIP Standards)_sb_rc	Recirculation Ballot	12/20/2010	12/30/2010	Quorum: 90.49% Approval: 80.56%			
159	Project 2010-11	Project 2010-11 TPL Table 1 Footnote B SAR_in	Recirculation Ballot	12/27/2010	1/5/2011	Quorum: 90.42% Approval: 83.33%			
160	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-002-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.62% Approval: 22.09%	Oppose 12/16/11		
161	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-003-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.62% Approval: 33.49%	Oppose 12/16/11		
162	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-004-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.60% Approval: 26.82%	Oppose 12/16/11		
163	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-005-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.60% Approval: 28.04%	Oppose 12/16/11		
164	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-006-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.61% Approval: 29.60%	Oppose 12/16/11		
165	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-007-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.61% Approval: 24.15%	Oppose 12/16/11		

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		

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
386	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Successive Ballot	3/27/2013	4/5/2013	Quorum: 78.39% Approval: 57.50%	No Consensus 4/4/13		The RSC did not reach a full consensus however the majority of respondents had indicated they will support the standard - see comment form for further details. Some believe the standard is not necessary and that existing whitepapers alleviate the need for it. In recognition of the NERC BOT's expectations that COM-003 will be approved by the industry and brought before them for approval, NPCC has voted affirmatively and will supply comments for the record outlining our concerns.
387	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Non-binding Poll	3/27/2013	4/5/2013	Quorum: 77.97% Approval: 54.28%			
388	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-001-2	Initial Ballot	4/16/2013	4/25/2013	Quorum: 88.60% Approval: 66.98%	No Consensus 4/23/13		The majority of NPCC's Balancing Authorities have indicated support for the standard, however NPCC as the Regional Entity has concerns based on results of the field trials that were conducted. These field trials have indicated the potential for an increased number of SOL violations as well as potential for increased ACE due to large inadvertent flows with the proposed BAAL limits based on frequency triggers. To be respectful of the positions of the NPCC BAs who will have to implement this new methodology and the support expressed, NPCC as the Regional Entity will cast an Abstention
389	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-002-2	Initial Ballot	4/16/2013	4/25/2013	Quorum: 88.51% Approval: 42.75%	Oppose 4/23/13		There is a lack of technical justification for the 500 MW threshold within the standard-NPCC will submit suggested improvements

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
390	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-013-1	Initial Ballot	4/16/2013	4/25/2013	Quorum: 88.51% Approval: 23.84%	Oppose 4/23/13		Losses of large blocks of load are typically caused by coincident transmission contingencies. Excessive and uninformed adjustments made to generation in order to bring the ACE to zero may well lead to further transmission issues. NPCC will submit suggested improvements
391	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-001-2	Non-binding Poll	4/16/2013	4/25/2013	Quorum: % Approval: %			
392	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-002-2	Non-binding Poll	4/16/2013	4/25/2013	Quorum: % Approval: %			
393	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-013-1	Non-binding Poll	4/16/2013	4/25/2013	Quorum: % Approval: %			
394	Project 2012-08.1	Project 2012-08.1 - Phase 1 of Glossary Updates: Statutory Definitions	Recirculation Ballot	4/18/2013	4/29/2013	Quorum: 80.70% Approval: 88.15%	No Consensus 3/22/13		
395	Project 2010-13.2	Project 2010-13.2 Phase 2 of Relay Loadability: Generation	Successive ballot	5/15/2013	5/24/2013	Quorum: 81.25% Approval: 69.23%	Support 5/23/13		The Regional Standard Committee has not expressed any concerns of significance that would warrant a ballot to reject, therefore the RSC recommends a yes vote, "Affirmative", to accept the standard
396	Project 2010-13.2	Project 2010-13.2 Phase 2 of Relay Loadability: Generation	Non-binding Poll	5/15/2013	5/24/2013	Quorum: 80.17% Approval: 61.11%			
397	Project 2007-06	Project 2007-06 - System Protection Coordination - PRC-001 and PRC-027	Successive Ballot	6/24/2013	7/3/2013	Quorum: 77.65% Approval: 52.71%			
398	Project 2007-06	Project 2007-06 - System Protection Coordination - PRC-001 and PRC-027	Non-binding Poll	6/24/2013	7/3/2013	Quorum: 77.12% Approval: 52.48%			
399	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	Initial Ballot	7/3/2013	7/12/2013	Quorum: 85.53% Approval: 49.73%			
400	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-003	Successive Ballot	7/10/2013	7/19/2013	Quorum: 76.32% Approval: 58.36%	No Consensus 7/19/13 [Due to the concerns expressed over the potential actions by the NERC BOT and FERC as well as the incremental improvement of the standard over the previous versions, NPCC as the Regional Entity will support the standard and submit comments.]		organizations support the standard as written however some members expressed concern that in order to measure compliance with R1 and R2, the standard will require all Reliability Directives to be investigated to determine if RC approved and documented communication protocols have been violated. Also it was identified that TO, BA communication protocols would have to approved by the RC potentially causing some legal issues if protocols aren't approved and casts question on the enforcement of those protocols. NPCC will be submitting some helpful comments should the standard pass and some non-substantive revision be performed prior to the "final" (previously named recirculation) ballot.
401	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-003	Non-binding Poll	7/10/2013	7/19/2013	Quorum: 76.20% Approval: 55.37%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
402	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-025	Successive Ballot	7/10/2013	7/19/2013	Quorum: 85.05% Approval: 72.43%	Support 7/19/13		
403	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-025	Non-binding Poll	7/10/2013	7/19/2013	Quorum: 82.51% Approval: 64.59%			
404	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-001-2	Final Ballot	7/16/2013	7/25/2013	Quorum: 92.31% Approval: 74.54%	No Consensus 7/22/13		The RSC has not reached a full consensus however the majority are in support. Issues outstanding for those not in support are concern over "hitting limits" more frequently and potential issues with BA's potentially "dragging" on the interconnection. NPCC will be voting affirmative on the standard.
405	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-023-3	Initial Ballot	7/26/2013	8/5/2013	Quorum: 80.05% Approval: 93.00%	Support 8/5/13		
408	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-025-1	Final Ballot	8/2/2013	8/12/2013	Quorum: 89.13% Approval: 76.52%	Support 8/12/13		
406	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation - EOP-010-1	Initial Ballot	8/2/2013	8/12/2013	Quorum: 76.32% Approval: 62.74%	Support 8/9/13		
407	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation - EOP-010-1	Non-binding Poll	8/2/2013	8/12/2013	Quorum: 75.89% Approval: 55.45%			
409	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Reclosing Relays) - PRC-005-3	Initial Ballot	8/14/2013	8/23/2013	Quorum: 78.33% Approval: 79.42%	Support 8/23/13		
410	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Reclosing Relays) - PRC-005-3	Non-binding Poll	8/14/2013	8/23/2013	Quorum: 77.45% Approval: 81.37%			
411	Project 2012-05	Project 2012-05 ATC Revisions (MOD A) - MOD-001-2	Ballot	8/16/2013	8/26/2013	Quorum: 76.14% Approval: 51.10%	No Consensus 8/26/13		NPCC to support with comments
412	Project 2012-05	Project 2012-05 ATC Revisions (MOD A) - MOD-001-2	Non-binding Poll	8/16/2013	8/26/2013	Quorum: 75.98% Approval: 53.29%			
413	Project 2010-01	Project 2010-01 - Training - PER-005-2	Ballot	8/23/2013	9/3/2013	Quorum: 75.25% Approval: 34.46%	No Consensus 8/31/13		NPCC to support with comments The most contentious issues raised by RSC members was surrounding the Control Center definition and the potential to vastly expand those needing training subject to the standard and compliance and that there was no need for a standard, rather, the FERC Directives should be addressed through other means.
414	Project 2010-01	Project 2010-01 - Training - PER-005-2	Non-binding Poll	8/23/2013	9/3/2013	Quorum: 80.45% Approval: 34.24%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
415	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4, VAR-002-3	Ballot	8/23/2013	9/3/2013	Quorum: 81.89% Approval: 43.79%	Oppose 8/31/13		The standard, in the view of the group, has extensive issues including but not limited to, applicability issues, lacks clarity, missing measures, quality, and other substantive issues. NPCC will be submitting detailed comments to address these issues. The RSC does not believe it would be beneficial to support the standard at this point as the next step, if it fails the initial ballot, would still require an additional ballot prior to moving to recirculation due to the substantive changes that are needed for the next revision. NPCC will be submitting helpful comments to NERC and supporting the drafting team effort.
416	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4, VAR-002-3	Non-binding Poll	8/23/2013	9/3/2013	Quorum: 79.95% Approval: 44.23%			
417	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-032-1, MOD-033-1	Ballot	8/26/2013	9/4/2013	Quorum: 82.29% Approval: 41.24%	Support 8/31/13		
418	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-032-1, MOD-033-1	Non-binding Poll	8/26/2013	9/4/2013	Quorum: 79.66% Approval: 40.00%			
419	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	Ballot	8/26/2013	9/4/2013	Quorum: 81.96% Approval: 55.76%	Support 8/31/13		
420	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	Non-binding Poll	8/26/2013	9/4/2013	Quorum: 80.35% Approval: 58.97%			
421	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	Additional Ballot	8/26/2013	9/4/2013	Quorum: 78.68% Approval: 66.11%	Support 8/31/13		
426	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-023-3	Final Ballot	9/4/2013	9/13/2013	Quorum: 85.93% Approval: 90.83%	Support 8/5/13		
422	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves - BAL-002-2, BAL-013-1	Ballot	9/6/2013	9/16/2013	Quorum: 76.15% Approval: 58.23%	No Consensus 9/12/13		
423	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves - BAL-002-2, BAL-013-1	Non-binding Poll	9/6/2013	9/16/2013	Quorum: 75.69% Approval: 59.66%			
424	Project 2012-INT-04	Project 2012-INT-04 - Interpretation of CIP-007-3 for ITC	Final Ballot	9/11/2013	9/20/2013	Quorum: 91.64% Approval: 98.61%	Support 3/14/13		
425	Project 2012-INT-06	Project 2012-INT-06 - Interpretation of CIP-003-3 for Consumers Energy	Final Ballot	9/11/2013	9/20/2013	Quorum: 90.98% Approval: 98.92%	Support 3/14/13		
427	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation - EOP-010-1	Additional Ballot	10/9/2013	10/21/2013	Quorum: 77.58% Approval: 88.75%	Support 10/16/13		
428	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation - EOP-010-1	Non-binding Poll	10/9/2013	10/21/2013	Quorum: 75.89% Approval: 90.04%			
429	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Reclosing Relays) - PRC-005-3	Final Ballot	10/16/2013	10/25/2013	Quorum: 85.71% Approval: 85.38%			
430	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	Additional Ballot	10/18/2013	10/29/2013	Quorum: 75.83% Approval: 72.55%	Support 10/21/13		
431	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation - EOP-010-1	Final Ballot	10/25/2013	11/4/2013	Quorum: 86.90% Approval: 91.95%			
432	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-002-4	Additional Ballot	10/25/2013	11/7/2013	Quorum: 76.67% Approval: 58.24%	No Consensus 11/1/13		
433	Project 2010-01	Project 2010-01 - Training - PER-005-2	Additional Ballot	11/1/2013	11/12/2013	Quorum: 76.23% Approval: 56.48%	Support 11/11/13		

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
434	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-004-3	Initial Ballot	11/4/2013	11/13/2013	Quorum: 76.12% Approval: 67.35%	Support 11/5/13		
435	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-006-4	Initial Ballot	11/4/2013	11/13/2013	Quorum: 75.82% Approval: 75.58%	Support 11/5/13		
436	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-009-2	Initial Ballot	11/4/2013	11/13/2013	Quorum: 75.82% Approval: 68.40%	Support 11/5/13		
437	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-010-2	Initial Ballot	11/4/2013	11/13/2013	Quorum: 75.82% Approval: 58.03%	Support 11/5/13		
438	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-011-1	Initial Ballot	11/4/2013	11/13/2013	Quorum: 75.52% Approval: 71.35%	Support 11/5/13		
439	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - Definition	Initial Ballot	11/4/2013	11/15/2013	Quorum: 76.42% Approval: 77.82%	Support 11/5/13		
440	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	Final Ballot	11/8/2013	11/18/2013	Quorum: 81.68% Approval: 74.34%	Support 10/21/13		
441	Project 2012-05	Project 2012-05 ATC Revisions (MOD A) - MOD-001-2	Additional Ballot	11/8/2013	11/20/2013	Quorum: 81.69% Approval: 82.97%	No Consensus 8/26/13		
442	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-032-1	Additional Ballot	11/8/2013	11/20/2013	Quorum: 79.05% Approval: 73.46%	Support 8/31/13		
443	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-033-1	Additional Ballot	11/8/2013	11/20/2013	Quorum: 79.84% Approval: 69.42%	Support 8/31/13		
444	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	Additional Ballot	11/13/2013	11/22/2013	Quorum: 80.54% Approval: 57.59%	Support 8/31/13		
445	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4	Additional Ballot	11/15/2013	11/25/2013	Quorum: 80.81% Approval: 69.43%			
446	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-002-3	Additional Ballot	11/15/2013	11/25/2013	Quorum: 81.06% Approval: 66.09%			
447	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves - BAL-002-2	Additional Ballot	12/2/2013	12/12/2013	Quorum: 75.29% Approval: 64.24%	No Consensus 12/9/13	Affirmative	
448	Project 2007-11	Project 2007-11 Disturbance Monitoring - PRC-002-2	Initial Ballot	12/6/2013	12/16/2013	Quorum: 82.25% Approval: 43.29%	No Consensus 12/15/13	Affirmative	Highlights of comments received expressed: • Agreement with the methodology to determine BES locations for which data had to be captured • Use of the term "locations" • DDR for Flowgates, IROLs • Clarification needed for some data that is to be captured • Editorial suggestions
449	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-032-1	Final Ballot	12/6/2013	12/16/2013	Quorum: 87.53% Approval: 77.49%	Support 8/31/13	Affirmative	
450	Project 2008-12	Project 2008-12 Coordinate Interchange Standards - INT-006-4	Final Ballot	12/10/2013	12/20/2013	Quorum: 85.07% Approval: 80.77%	Support 11/5/13	Affirmative	
451	Project 2008-12	Project 2008-12 Coordinate Interchange Standards - INT-009-2	Final Ballot	12/10/2013	12/20/2013	Quorum: 85.07% Approval: 72.86%	Support 11/5/13	Affirmative	
452	Project 2008-12	Project 2008-12 Coordinate Interchange Standards - INT-011-1	Final Ballot	12/10/2013	12/20/2013	Quorum: 84.78% Approval: 72.91%	Support 11/5/13	Affirmative	
453	Project 2012-05	Project 2012-05 ATC Revisions (MOD A) - MOD-001-2	Final Ballot	12/11/2013	12/20/2013	Quorum: 87.16% Approval: 86.40%	No Consensus 8/26/13	Affirmative	
454	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4	Final Ballot	12/13/2013	12/23/2013	Quorum: 84.34% Approval: 75.35%		Affirmative	
455	Project 2007-06	Project 2007-06 - System Protection Coordination - PRC-027-1	Additional Ballot	12/9/2013	12/31/2013	Quorum: 76.60% Approval: 65.71%	No Consensus 12/27/13	Affirmative	
456	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-033-1	Additional Ballot	1/10/2014	1/21/2014	Quorum: 76.92% Approval: 81.41%	Support 8/31/13	Affirmative	
457	Project 2010-01	Project 2010-01 - Training - PER-005-2	Additional Ballot	1/8/2014	1/22/2014	Quorum: 7912% Approval: 74.63%	Support 11/11/13	Affirmative	
458	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-004-3	Additional Ballot	1/10/2014	1/22/2014	Quorum: 75.22% Approval: 81.19%	Support 11/5/13	Affirmative	
459	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-010-2	Additional Ballot	1/10/2014	1/22/2014	Quorum: 75.22% Approval: 90.23%	Support 11/5/13	Affirmative	

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments	
460	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - Definition	Additional Ballot	1/16/2014	1/29/2014	Quorum: 76.12% Approval: 92.17%	Support 11/5/13	Affirmative		
461	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-002-4	Additional Ballot	1/22/2014	1/31/2014	Quorum: 76.03% Approval: 71.86%	No Consensus 11/1/13	Affirmative	Ballot Period Extended to 2/4/14	
462	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-004-3	Final Ballot	1/27/2014	2/5/2014	Quorum: 83.88% Approval: 83.44%	Support 11/5/13	Affirmative		
463	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-010-2	Final Ballot	1/27/2014	2/5/2014	Quorum: 83.58% Approval: 91.51%	Support 11/5/13	Affirmative		
464	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-033-1	Final Ballot	1/27/2014	2/5/2014	Quorum: 82.49% Approval: 82.45%	Support 8/31/13	Affirmative		
465	Project 2010-01	Project 2010-01 - Training - PER-005-2	Final Ballot	1/27/2014	2/5/2014	Quorum: 84.02% Approval: 77.06%	Support 11/11/13	Affirmative		
466	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - Definition	Final Ballot	1/31/2014	2/10/2014	Quorum: 81.79% Approval: 90.12%	Support 11/5/13	Affirmative		
467	Project 2010-05.1	Project 2010-05.1 –Protection Systems: Phase 1 (Misoperations): PRC-004-3	Additional Ballot	2/21/2014	3/3/2014	Quorum: 75.06% Approval: 62.63%	Support 9/5/12	Affirmative	Ballot Period Extended to 3/11/14	
468	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-002-4	Final Ballot	3/28/2014	4/7/2014	Quorum: 78.21% Approval: 77.62%	Support 3/28/14	Affirmative		
469	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	Additional Ballot	4/1/2014	4/10/2014	Quorum: 76.92% Approval: 83.40%	Support 8/31/13	Affirmative		
470	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-002-3	Additional Ballot	4/4/2014	4/14/2014	Quorum: 78.03% Approval: 82.40%		--		
471	Project 2014-04	Project 2014-04 Physical Security - CIP-014-1	Initial Ballot	4/20/2014	4/24/2014	Quorum: 88.60% Approval: 82.07%	Support 4/23/14	Abstain		
472	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	Final Ballot	4/25/2014	5/5/2014	Quorum: 80.37% Approval: 90.00%	Support--4/25/14	Affirmative		
473	Project 2013-04	Project 2013-04 - Voltage and Reactive Control - VAR-001-4, VAR-002-3	Final Ballot	4/23/2014	5/5/2014	Quorum: 83.84% Approval: 88.26%	Support--4/10/14	Affirmative		
474	Project 2014-04	Project 2014-04 - Physical Security - CIP-014-1	Final Ballot	5/1/2014	5/5/2014	Quorum: 92.53% Approval: 85.61%	Support--4/23/14	Abstain		
475	Project 2010-02	Project 2010-02 - Connecting Facilities to the Grid - FAC-001-2 and FAC-002-2	Initial Ballot	5/6/2014	5/15/2014	Quorum: 85.79%/79.08% Approval: 86.28%/78.81%	No Consensus--5/15/14	Reject		
476	Project 2012-13	Project 2012-13 - NUC - Nuclear Plant Interface Coordination	Initial Ballot	5/13/2014	5/22/2014	Quorum: 80.60% Approval: 97.36%	Support--5/20/14	Affirmative		
477	Project 2007-17.3	Project 2007-17.3 - Protection System Maintenance and Testing - Phase 3 (Sudden Pressure Relays) - PRC-005-X	Initial Ballot	5/23/2014	6/2/2014	Quorum: 85.42% Approval: 47.89%	Support	Affirmative		
478	Project 2010-13.3	Project 2010-13.3 - Phase 3 of Relay Loadability: Stable Power Swings	Initial Ballot	5/30/2014	6/9/2014	Quorum: 79.06% Approval: 17.02%	Does not Support--6/6/14	Negative		
475	Project 2010-02	Project 2010-02 - Connecting Facilities to the Grid - FAC-001-2 and FAC-002-2	Final Ballot	6/12/2014	6/23/2014	Quorum: Approval: 89.03%/83.46%	Support	Affirmative		
479	Project 2007-11	Project 2007-11 - Disturbance Monitoring - PRC-002-2	Additional Ballot	6/13/2014	6/23/2014	Quorum: 77.69% Approval: 52.29%	Support	Affirmative	Extended to achieve a quorum.	Last RSC Meeting
480	Project 2010-05.1	Project 2010-05.1 - Protection System: Phase 1 (Misoperations) - PRC-004	Additional Ballot	6/20/2014	7/9/2014	Quorum: 76.98% Approval: 74.53%	Support	Affirmative	Extended to achieve a quorum.	
481	Project 2014-03	Project 2014-03 - Revisions to TOP/IRO Reliability Standards	Ballot	6/23/2014	7/2/2014	Quorum: 82.32%/82.59%/82.59%/82.85%/82.85%/82.06%/82.59%/82.85%/82.85%/81.00%/80.74% Approval: 68.57%/36.94%/47.87%/60.26%/61.67%/57.94%/30.99%/62.18%/63.07%/62.64%/64.70%	No Consensus--6/24/14	Affirmative Negative Affirmative Affirmative Affirmative Affirmative Negative Affirmative Affirmative		
482	Project 2012-13	Project 2012-13 NUC - Nuclear Plant Interface Coordination	Final Ballot	6/24/2014	7/3/2014	Quorum: 88.63% Approval: 97.23%	Support--6/23/14	Affirmative		
483	Project 2014-02	Project 2014-02 Critical Infrastructure Protection Standards Version 5 Revisions Rich HTML Content 1	Final Ballot	7/7/2014	7/16/2014	Quorum: 80.73%/80.49%/80.00%/80.24%/80.24%/80.49%/80.24%/78.29%	CIP-003 No CIP-004 Yes CIP-006 Yes CIP-007 Yes CIP-009 Yes			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
483	Project 2014-02	Rich Hydro Content 1 http://www.nerc.com/pa/Stand/Pages/Project-2014-XX-Critical-Infrastructure-Protection-Version-5-Revisions.aspx	Final Ballot	7/7/2014	7/16/2014	Approval: 35.67%/80.76%/76.24%/78.41%/85.32%/49.42%/82.55%/78.58%	CIP-003 Yes CIP-010 Yes CIP-011 Yes Definitions Yes Support--7/14/14		
484	Project 2010-05.2	Project 2010-05.2 – Special Protection Systems (Phase 2 of Protection Systems)	Final Ballot	7/16/2014	7/25/2014	Quorum: 78.92% Approval: 58.88%	Support--7/23/14		
485	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Final Ballot	7/18/2014	7/28/2014	Quorum: 79.49%/80.15%/80.00%/80.83%/80.36% Approval: 91.38%/92.20%/89.51%/90.58%/87.09%	Support--7/24/14	Affirmative	
486	Project 2012-13	Project 2013-03 Geomagnetic Disturbance Mitigation	Final Ballot	7/21/2014	7/30/2014	Quorum: 82.67% Approval: 55.77%		Affirmative	
487	Project 2012-13	Project 2008-02 Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS)	Initial Ballot	7/29/2014	8/7/2014	Quorum: 76.37% Approval: 76.91%		Affirmative	
488	Project 2012-13	Project 2009-03 Emergency Operations	Initial Ballot	8/6/2014	8/15/2014	Quorum: 77.66% Approval: 42.27%	Negative--8/14/14	Negative	
489	Project 2014-01	Project 2010-05.1 - Protection System: Phase 1 (Misoperations) - PRC-004	Final Ballot	7/29/2014	8/7/2014	Quorum: 77.94% Approval: 79.75%	Support	Affirmative	
490	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Final Ballot	8/27/2014	9/5/2014	Quorum: 85.32%/86.01% Approval: 95.35%/95.86%	Support	Affirmative	
491	Project 2007-17.3	Project 2007-17.3 - Protection System Maintenance and	Additional Ballot	9/3/2014	9/12/2014	Quorum: 84.33% Approval: 76.03%	Support--9/4/14	Affirmative	
492	Project 2014-03	Project 2014-03 - Revisions to TOP/IRO Reliability Standards	Additional Ballot	9/10/2014	9/19/2014	Quorum: 85.75%/84.96%/84.96%/85.22%/84.96%/85.22%/85.49%/85.22%/86.28%/83.11%/83.91% Approval: 76.12%/74.23%/75.67%/85.49%/75.96%/78.67%/48.73%/78.87%/87.03%/93.34%/90.13%	TOP-001-3: Negative TOP-002-4: Affirmative TOP-003-3: Affirmative IRO-001-4: No consensus however the majority indicated an Affirmative vote IRO-002-4: Negative IRO-008-2: No consensus, a majority indicated a Negative and the others indicated abstention IRO-010-2: Affirmative IRO-014-3: Negative IRO-017-1: Affirmative Implementation Plan and Definitions: Affirmative 9/18/14		
493	Project 2010-14.1	Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves	Additional Ballot	9/23/2014	10/2/2014	Quorum: 79.94% Approval: 46.73%	Negative--10/1/14		
494	Project 2010-13.3	Project 2010-13.3 - Phase 3 of Relay Loadability: Stable Power Swings	Additional Ballot	9/26/2014	10/6/2014	Quorum: 79.01% Approval: 53.02%	Affirmative--10/1/14		
495	Project 2012-13	Project 2008-02 Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS)	Additional Ballot	9/29/2014	10/8/2014	Quorum: 83.24%/84.82% Approval: 80.69%/84.05%	Affirmative--10/7/14	Affirmative	
496	Project 2012-13	Project 2013-03 Geomagnetic Disturbance Mitigation	Additional Ballot	10/1/2014	10/10/2014	Quorum: 82.93% Approval: 57.95%	Affirmative--10/7/14		
497	Project 2010-05.2	Project 2010-05.2 – Special Protection Systems (Phase 2 of Protection Systems)	Additional Ballot	10/3/2014	10/14/2014	Quorum: 80.54% Approval: 75.79% Approval:	Affirmative--10/7/14		
498	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Additional Ballot	10/7/2014	10/16/2014	Quorum: 81.91%/82.12% Approval: 94.92%/94.37%	Affirmative--10/14/14		

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
499	Project 2014-02	Project 2014-02 Critical Infrastructure Protection Standards Version 5 Revisions	Additional Ballot	10/8/2014	10/17/2014	Quorum: 84.63%/84.15%/84.15%/83.90%/83.41%/83.66%/83.96%/84.49%/83.96%/83.96%/84.22 Approval: 93.21%/68.09%/74.25%/79.91%/85.68%/89.01%/91.79%/81.34%/96.63%/96.63%/95.52%/85.93%/98.13%	CIP-003-6 no consensus CIP-010-2 no consensus New Definitions-Affirmative Updated Definitions-Affirmative Implementation Plan-Affirmative Version X Materials-Affirmative Non-binding polls-Affirmative	CIP-003-6 and CIP-010-2 Affirmative	
500	Project 2009-03	Project 2009-03 Emergency Operations	Additional Ballot	10/10/2014	10/20/2014	Quorum: 80.93% Approval: 70.41%	Affirmative--10/17/14		
501	Project 2014-03	2014-03 - Revisions to TOP and IRO Standards (IRO-001-4, IRO-002-4, IRO-010-2, two Definitions, and Implementation Plan)	Final Ballot	10/10/2014	10/20/2014	Quorum: 90/77%/89.97%/89.97%/88.39%/88.39% Approval: 82.64%/85.96%/86.22%/94.07%/91.84%	Affirmative--10/17/14		
502	Project 2014-03	2014-03 - Revisions to TOP and IRO Standards (TOP-002-4, TOP-003-3, IRO-008-2, IRO-014-3, and IRO-017-1)	Final Ballot	10/10/2014	10/20/2014	Quorum: 89.71%/88.39%/89.71%/89.71%/89.97% 84.76%/86.55%/83.73%/89.88%/82.58%	Affirmative--10/17/14		
503	Project 2007-11	Project 2007-11 Disturbance Monitoring	Additional Ballot	10/10/2014	10/21/2014	Quorum: 77..69% Approval: 71.38%	Affirmative--10/17/14		
504	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Additional Ballot	10/10/2014	10/22/2014	Quorum: 85.13%/83.29% Approval: 94.75%/93.98%	Affirmative--10/20/14		
505	Project 2014-03	Project 2007-17.3 (PRC-005-X) Protection System Maintenance and Testing - Phase 3 (Sudden Pressure Relays)	Final Ballot	10/20/2014	10/29/2014	Quorum: 88.25% Approval: 74.14%	Affirmative--10/28/14		
506	Project 2014-03	Project 2008-02 Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS)	Final Ballot	10/28/2014	11/6/2014	Quorum: 87.53% Approval: 83.12%	Affirmative--10/31/14		
507	Project 2007-11	Project 2007-11 Disturbance Monitoring	Final Ballot	10/28/2014	11/6/2014	Quorum: 81.89% Approval: 68.51%	Affirmative--10/31/14		
508	Project 2007-11	Project 2010-05.2 Phase 2 of Special Protection Systems	Final Ballot	10/28/2014	11/6/2014	Quorum: 85.41% Approval: 73.33%	Negative--10/14/14		
509	Project 2007-11	Project 2009-03 Emergency Operations	Final Ballot	10/28/2014	11/6/2014	Quorum: 87.19% Approval: 73.20%	Affirmative--10/17/14		
510	Project 2007-11	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Final Ballot	10/28/2014	11/6/2014	Quorum: 89.49%/87.66%/87.08% Approval: 92.91%/92.15%/95.62%	Affirmative--10/20/14		
511	Project 2014-03	Project 2014-02 Critical Infrastructure Protection Standards Version 5 Revisions	Final Ballot	10/28/2014	11/6/2014	Quorum: 87.56%/87.32%87.07%/87.56%/87.80%87.56%86.59% Approval: 83.84%/95.34%/86.00%/95.35%91.17%/83.88%/95.40%/92.76%	CIP-003-6 no consensus CIP-010-2 no consensus New Definitions-Affirmative Updated Definitions-Affirmative Implementation Plan-Affirmative Version X Materials-Affirmative Non-binding polls-Affirmative		
512	Project 2014-03	2014-03 - Revisions to TOP and IRO Standards	Additional Ballot	11/4/2014	11/10/2014	Quorum: 78.36% Approval: 60.21%	Affirmative--11/4/14		
513	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation	Additional Ballot	11/12/2014	11/21/2014	Quorum: 79.73% Approval: 77.29%	Affirmative--11/21/14		
514	Project 2014-03	Project 2010-13.3 Phase 3 of Relay Loadability: Stable Power Swings	Additional Ballot	11/14/2014	11/24/2014	Quorum: 79.83% Approval: 67.39%	Affirmative--10/1/14		
515	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation	Final Ballot	12/5/2014	12/16/2014	Quorum: 84.27% Approval: 78.05%	Affirmative--12/12/14		

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
516	Project 2014-03	Project 2010-13.3 Phase 3 of Relay Loadability: Stable Power Swings	Final Ballot	12/5/2014	12/16/2014	Quorum: 84.81% Approval: 68.08%	Affirmative--12/15/14		
517	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Initial Ballots	12/10/2014	12/23/2014	Quorum: 79.38%/79.72%/79.60 % Approval: 92.69%/93.55%/93.67 %	Affirmative--12/22/14		
518	Project 2014-03	2014-03 - Revisions to TOP and IRO Standards	Additional Ballot	12/19/2014	1/7/2015	Quorum: 80.47% Approval: 72.43%	Affirmative--1/6/15		
519	Project 2014-02	2014-02 - Critical Infrastructure Protection Standards Version 5 Revisions	Additional Ballot	12/30/2014	1/9/2015	Quorum: 81.22%/81.71%/81.46 %/81.71%/81.71%/81. 22%/81.71%/81.46% Approval: 81.92%/98.89%/98.86 %/88.13%/98.89%/86. 02%/89.63%/97.21%	CIP-003-7 Binding and non-binding polls-no consensus CIP-003-7 Definition-Affirmative CIP-010-7 Binding and non-binding polls- Affirmative CIP-010-7 Definition- Affirmative CIP-004-7 Binding and non-binding polls – Affirmative CIP-007-7 Binding and non-binding polls –Affirmative CIP-011-7 Binding and non-binding polls –Affirmative CIP Implementation Plan- Affirmative 1/8/2015		
520	Project 2014-03	2014-03 - Revisions to TOP and IRO Standards - TOP-001-3	Final Ballots	1/15/2015	1/21/2015	Quorum: 84.70% Approval: 72.69%	Affirmative--1/6/15		
521	Project 2014-01	2014-01 - Standards Applicability for Dispersed Generation Resources - PRC-005-5	Initial Ballots	1/12/2015	1/22/2015	Quorum: 77.93% Approval: 93.74%	Affirmative--1/22/15		
522	Project 2014-01	2014-01 - Standards Applicability for Dispersed Generation Resources - PRC-001-1.1(ii), PRC-019-2, and PRC-024-2	Final Ballots	1/13/2015	1/22/2015	Quorum: 89.27%/89.30%/89.52 % Approval: 93.99%/94.03%/95.82 %	Affirmative--1/22/15		
523	Project 2014-02	2014-02 - Critical Infrastructure Protection Standards Version 5 Revisions CIP-003-7, CIP-004-7, CIP-010-3, and CIP-011-3	Final Ballot	1/23/2015	2/2/2015	Quorum: 84.15%/84.39%/84.15 %/84.39%/84.39%/83. 90%/84.39%/83.66% Approval: 79.76%/98.94%/98.94 %/86.76%/98.93%/84. 07%/90.10%/97.32%	Affirmative--1/29/15		
524	Project 2014-01	2014-01 - Standards Applicability for Dispersed Generation Resources - PRC-005-5	Final Ballot	3/2/2015	3/11/2015	Quorum: 83.52% Approval: 98.03%	Affirmative--1/22/15		
525	Project 2010-14.1	Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves	Additional Ballot	3/6/2015	3/16/2015	Quorum: 77.29% Approval: 59.30%	Negative--3/13/2015		
526	Project 2008-02.2	Project 2008-02.2 Phase 2 of Undervoltage Load Shedding (UVLS): Misoperations	Initial Ballot	3/27/2015	4/7/2015	Quorum: 79.93% Approval: 84.31%	Affirmative--3/31/15		
527	Project 2014-04	Project 2014-04 Physical Security	Initial Ballot	3/31/2015	4/9/2015	Quorum: 88.33% Approval: 89.95%	Affirmative--3/31/15		
528	Project 2008-02.2	Project 2008-02.2 Phase 2 of Undervoltage Load Shedding (UVLS): Misoperations	Final Ballot	4/17/2015	4/27/2015	Quorum: 84.86% Approval: 89.63%	Affirmative--3/31/15		
529	Project 2014-04	Project 2014-04 Physical Security	Final Ballot	4/20/2015	4/29/2015	Quorum: 92.00% Approval: 92.35%	Affirmative--3/31/15		
530	Project 2007-06	Project 2007-06 System Protection Coordination	Additional Ballot	5/6/2015	5/15/2015	Quorum: 81.79% Approval: 39.63%	Negative--5//13/15		
531	Project 2015-06	2015-06 Interconnection Reliability Operations and Coordination	Initial Ballot	6/29/2015	7/8/2015	Quorum: 75.23%/84.00% Approval: 90.35%/97.50%	Affirmative--7/7/15		

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
532	Project 2015-04	2015-04 Alignment of Terms	Initial Ballot	7/17/2015	7/27/2015	Quorum: 90.43%/91.17%/91.10%/91.01%/91.10%/91.17%/91.17%/91.34%/90.97%/91.40%/90.10%/91.01%/91.07%/91.07%/91.07%/91.34%/91.43%/90.75%/91.34%/91.01%/91.40%/91.01%/91.01%/91.01%/91.01%/91.01% Approval: 91.46%/88.57%/86.68%/97.06%/97.10%/81.06%/80.73%/96.38%/97.03%/69.80%/95.38%/93.62%/96.83%/97.00%/98.55%/87.37%/89.99%/84.38%/88.06%/90.37%/97.75%/91.28%/87.71%/89.44%/87.15%/98.24%	Affirmative--7/24/15		
533	Project 2015-06	2015-06 Interconnection Reliability Operations and Coordination	Final Ballots	7/22/2015	7/31/2015	Quorum: 85.98%/90.67%% Approval: 88.23%/96.84%	Affirmative--7/7/15		
534	Project 2010-14.1	Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves	Additional Ballot	8/11/2015	8/20/2015	Quorum: 75.92% Approval: 69.26%	Affirmative--8/17/15		
535	Project 2007-06	Project 2007-06 System Protection Coordination	Additional Ballot	9/2/2015	9/11/2015	Quorum: 84.34% Approval: 69.76%	Affirmative--9/8/15		
536	Project 2007-06	Project 2007-06.2 Phase 2 of System Protection Coordination	Initial Ballot	9/2/2015	9/11/2015	Quorum: 87.16% Approval: 62.55%	Affirmative--9/11/15		
537	Project 2010-14.2.1	Project 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls – BAL-005 and BAL-006	Initial Ballot	9/4/2015	9/14/2015	Quorum: 83.81% Approval: 55.97%	Abstention--9/14/15		
538	Project 2015-04	2015-04 Alignment of Terms	Final Ballot	9/4/2015	9/14/2015	Quorum: 96.81%/97.53%/97.51%/97.48%/97.51%/97.53%/97.53%/97.11%/97.11%/97.85%/96.80%/97.12%/97.14%/97.14%/97.14%/97.11%/97.14%/96.80%/97.11%/97.48%/97.85%/97.48%/97.48%/97.48%/97.48%/97.48% Approval: 93.13%/92.89%/91.33%/98.07%/98.07%/84.78%/84.75%/98.30%/98.06%/75.63%/95.46%/94.48%/98.31%/97.11%/98.57%/90.80%/95.60%/90.46%/92.07%/92.49%/97.81%/92.84%/91.09%/91.32%/90.80%/98.29%	Affirmative--7/24/15		
539	Project 2007-17.4	Project 2007-17.4 PRC-005 FERC Order No. 803 Directive	Initial Ballot	9/4/2015	9/16/2015	Quorum: 86.97% Approval: 96.73%	Affirmative--9/16/15		
540	Project 2010-04.1	Project 2010-04.1 MOD-031 FERC Order No. 804 Directives	Initial Ballot	9/9/2015	9/18/2015	Quorum: 85.57%	Affirmative--9/18/15		

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
						Approval: 87.36%			
541	Project 2010-05.3	Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS)	Initial Ballot	9/25/2015	10/5/2015	Quorum: 83.70% Approval: 48.10%	N egative--10/2/15		
542	Project 2010-05.3	Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves	Final Ballot	9/29/2015	10/8/2015	Quorum: 84.28% Approval: 74.61%	Affirmative--8/17/15		
543	Project 2010-05.3	Project 2007-06 System Protection Coordination	Final Ballot	10/5/2015	10/14/2015	Quorum: 89.16% Approval: 80.94%	Affirmative--9/8/15		
544	Project 2010-05.3	Project 2010-04.1 MOD-031 FERC Order No. 804 Directives	Final Ballot	10/6/2015	10/15/2015	Quorum: 89.60% Approval: 90.01%	Affirmative--9/18/15		
545	Project 2007-17.4	Project 2007-17.4 PRC-005 FERC Order No. 803 Directive	Final Ballot	10/15/2015	10/26/2015	Quorum: 90.00% Approval: 96.38%	Affirmative--9/16/15		
546	Project 2010-05.3	Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities	Initial Ballot	10/30/2015	11/9/2015	Quorum: 84.59%/84.49% Approval: 47.38%/48.00%	Abstention--11/5/15		
547	Project 2010-05.3	Project 2010-14.2.2 Phase 2 of Balancing Authority Reliability-based Controls - BAL-004-2	Initial Ballot	11/3/2015	11/12/2015	Quorum: 84.40% Approval: 98.17%	Affirmative--11/5/15		
548	Project 2015-07	Project 2015-07 Internal Communications Capabilities	Initial Ballot	11/6/2015	11/16/2015	Quorum: 88.18% Approval: 53.60%	Affirmative--11/13/15		
549	Project 2007-06.2	Project 2007-06.2 Phase 2 of System Protection Coordination	Additional Ballot	11/10/2015	11/19/2015	Quorum: 83.18% Approval: 57.29%	Affirmative--11/18/15		
550	Project 2010-07.1	Project 2010-07.1 Vegetation Management	Initial Ballot	12/7/2015	12/16/2015	Quorum: 85.38% Approval: 82.56%	Negative--12/8/15		
547	Project 2010-05.3	Project 2010-14.2.2 Phase 2 of Balancing Authority Reliability-based Controls - BAL-004-2	Final Ballot	12/8/2015	12/17/2015	Quorum: 88.65% Approval: 98.26%	Affirmative--11/5/15		
551	Project 2010-05.3	Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS)	Additional Ballot	12/30/2015	1/8/2016	Quorum: 83.39%/80.88% Approval: 60.39%/92.94%	Affirmative--12/3015		
552	Project 2010-14.2.1	Project 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls – BAL-005 and BAL-006	Additional Ballot	12/31/2015	1/11/2016	Quorum: 84.13%/83.17%/84.44% Approval: 70.64%/75.54%/94.30%	BAL-005-1--Negative--1/10/16 BAL-006--Affirmative--1/10/16 FAC-003-1--Abstention--1/10/16		
553	Project 2010-05.3	Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities	Additional Ballot	1/15/2016	1/25/2016	Quorum: 82.88%/82.18% Approval: 72.13%/68.01%	Affirmative--1/25/16		
554	Project 2010-07.1	Project 2010-07.1 Vegetation Management	Final Ballot	1/29/2016	2/8/2016	Quorum:90.03% Approval: 96.18%	Affirmative--2/1/16		
552	Project 2010-14.2.1	Project 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls – BAL-005 and BAL-006	Final Ballot	1/29/2016	2/8/2016	Quorum: 86.35%/86.98%/86.67% Approval: 72.06%/94.61%/80.15%	Affirmative--2/3/15		
551	Project 2010-05.3	Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities	Final Ballot	2/17/2016	2/26/2016	Quorum: 88.36%/87.79% Approval: 75.68%/73.87%	Affirmative--1/25/16		
552	Project 2010-05.3	Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS)	Additional Ballot	3/9/2016	3/18/2016	Quorum: 75.55% Approval: 78.87%	Affirmative--3/10/16		
553	Project 2007-06.2	Project 2007-06.2 Phase 2 of System Protection Coordination	Initial Ballot	4/15/2016	4/25/2016	Quorum: 83.39%/83.33% Approval: 80.57%/78..39%	Affirmative--4/20/16		
554	Project 2010-05.3	Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS)	Final Ballot	4/20/2016	4/29/2016	Quorum: 81.19%/87.15%	Affirmative--3/10/16		

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
						Approval: 80.36%/93.43%	~~Affirmative--5/16/16~~		
555	Project 2015-07	Project 2015-07 Internal Communications Capabilities	Additional Ballot	4/27/2016	5/6/2016	Quorum: 81.03% Approval: 82.64%	Affirmative--5/6/16		
556	Project 2007-06.2	Project 2007-06.2 Phase 2 of System Protection Coordination	Final Ballot	5/17/2016	5/26/2016	Quorum: 88.96%/88.36% Approval: 82.52%/83.37%	Affirmative--4/20/16		
557	Project 2015-07	Project 2015-07 Internal Communications Capabilities	Final Ballot	6/15/2016	6/24/2016	Quorum: 84.52% Approval: 83.25%	Affirmative--5/6/16		
558	Project 2016-01	Project 2016-01 Modifications to TOP and IRO Standards	Initial Ballot	7/25/2016	8/3/2016	Quorum: 84.50%/85.51% Approval: 67.25%/64.59%	Affirmative--8/1/16		
559	Project 2015-08	Project 2015-08 Emergency Operations EOP-005-3 EOP-006-3 EOP-008-2	Initial Ballot	8/4/2016	8/15/2016	Quorum: 80.45%/81.14%/80.79% Approval: 52.90%/66.87%/84.13%	Negative--8/4/16		
560	Project 2016-02	Project 2016-02 Modifications to CIP Standards	Initial Ballot	8/26/2016	9/6/2016	Quorum: 85.00%/84.37%/84.62% Approval: 41.54%/41.77%/30.63%	Negative--9/6/16		
561	Project 2015-08	Project 2015-08 Emergency Operations EOP-004-4	Initial Ballot	8/30/2016	9/8/2016	Quorum: 82.75% Approval: 80.32%	Affirmative--9/8/16		
562	Project 2015-INT-01	Project 2015-INT-01 Interpretation of CIP-002-5.1 for Energy Sector Security Consortium (EnergySec)	Initial Ballot	9/2/2016	9/12/2016	Quorum: 75.43% Approval: 91.68%	Affirmative--9/12/16		
563	Project 2016-01	Project 2016-01 Modifications to TOP and IRO Standards	Additional Ballot	10/5/2016	10/14/2016	Quorum: 83.33%/81.79% Approval: 70.77%/68.85%	Affirmative--10/13/16		
564	Project 2015-INT-01	Project 2015-INT-01 Interpretation of CIP-002-5.1 for Energy Sector Security Consortium (EnergySec)	Final Ballot	10/13/2016	10/24/2016	Quorum: 81.25% Approval: 91.31%	Affirmative--9/12/16		
565	Project 2016-02	Project 2016-02 Modifications to CIP Standards	Additional Ballot	11/23/2016	12/5/2016	Quorum: 76.40%/76.63% Approval: 85.56%/75.54%	Affirmative--12/1/16		
566	Project 2015-08	Project 2015-08 Emergency Operations EOP-005-3 and EOP-006-3	Additional Ballot	11/30/2016	12/9/2016	Quorum: 80.71%/82.43% Approval: 76.93%/77.17%	Affirmative--11/30/16		
567	Project 2015-08	Project 2015-08 Emergency Operations EOP-008-2	Final Ballot	11/30/2016	12/9/2016	Quorum: 93.36% Approval: 93.17%	Affirmative--11/30/16		
568	Project 2016-01	Project 2016-01 Modifications to TOP and IRO Standards	Final Ballot	12/2/2016	12/12/2016	Quorum: 90.74%/90.40% Approval: 74.30%/72.52%	Affirmative--12/2/16		
569	Project 2016-02	Project 2016-02 Modifications to CIP Standards | CIP-003-7 and Implementation	Final Ballot	12/9/2016	12/19/2016	Quorum: 82.89%/83.14% Approval: 87.95%/83.03%	Affirmative--12/1/16		
570	Project 2015-08	Project 2015-08 Emergency Operations EOP-004-4	Additional Ballot	12/28/2016	1/6/2017	Quorum: 79.47% Approval: 93.55%	Affirmative--1/4/17		
571	Project 2015-08	Project 2015-08 Emergency Operations EOP-005-3, EOP-006-3	Final Ballot	12/28/2016	1/6/2017	Quorum: 91.00%/91.55% Approval: 83.65%/80.56%	Affirmative--1/4/17		
572	Project 2016-02	Project 2016-02 Modifications to CIP Standards | CIP-003-7(i) Implementation Plan and 2 Definitions	Initial Ballot	1/16/2017	1/25/2017	Quorum: 77.81%/76.71%/77.26%/76.71%	~~Affirmative--1/23/17~~		

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
						Approval: 81.30%/87.87%/86.75%/86.47%	Affirmative--1/23/17		
573	Project 2016-03	Project 2016-03 Cyber Security Supply Chain Risk Management	Initial Ballot	2/24/2017	3/6/2017	Quorum: 87.13% Approval: 10.36%	Abstain--3/2/17		
574	Project 2015-08	Project 2015-08 Emergency Operations EOP-004-4	Final Ballot	1/24/2017	2/2/2017	Quorum: 84.46% Approval: 93.80%	Affirmative--1/4/17		
575	Project 2016-02	Project 2016-02 Modifications to CIP Standards | CIP-003-7(i) Implementation Plan and 2 Definitions	Final Ballot	1/30/2017	2/8/2017	Quorum: 86.58%/85.48%/86.03%/85.48% Approval: 78.55%/86.00%/85.81%/85.54%	Affirmative--1/23/17		
576	SPM	Revisions to the NERC Standards Process Manual	Initial Ballot	4/24/2017	5/3/2017	Quorum: 78.21% Approval: 64.72%			
577	Project 2016-03	Project 2016-03 Cyber Security Supply Chain Risk Management	Additional Ballot	6/6/2017	6/15/2017	Quorum: 76.02%/76.02%/77.21% Approval: 89.84%/82.92%/88.64%	Affirmative--6/8/17		
578	Project 2016-03	Project 2016-03 Cyber Security Supply Chain Risk Management	Final Ballot	7/11/2017	7/20/2017	Quorum: 81.59%/81.33%/82.84% Approval: 88.79%/81.40%/84.19%	Affirmative--6/8/17		
579	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation TPL-007-2	Initial Ballot	8/2/2017	8/11/2017	Quorum: 79.87% Approval: 72.67%	Affirmative--8/3/17		
580	Project 2016-04	Project 2016-04 Modifications to PRC-025-1	Initial Ballot	8/29/2017	9/8/2017	Quorum: 80.45% Approval: 78.79%	Affirmative--9/1/17		
581	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-012-1 Control Center Communication Networks	Initial Ballot	8/14/2017	9/12/2017	Quorum: 80.00%	Affirmative--9/1/17		

RSC Meeting #17-4, Agenda Item 6.3: Comment History

(As of 10/4/2017)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
1.	N/A	Standards Project Prioritization Reference Document and Tool	Project Prioritization Tool		1/21/11	2/10/11	Yes 2/10/11
2.	Project 2007-23	Project 2007-23 - Violation Severity Levels	VSLs		1/20/11	2/18/11	Yes 2/18/11
3.	N/A	CAN-0015--Draft CAN-0015 Unavailability of NERC Tools	CAN-0015 Unavailability of NERC Tools		2/4/11	2/18/11	Yes 2/18/11
4	N/A	CAN-0016--Draft CAN-0016 CIP-001-1 R1 - Applicability to Non-BES	CAN-0016 CIP-001-1, R1		2/4/11	2/18/11	Yes 2/18/11
5.	N/A	CAN-0018--Draft CAN-0018 FAC-008 R.1.2.1 - Terminal Equipment	CAN-0018 FAC-008, R.1.2.1		2/4/11	2/18/11	Yes 2/18/11
6.	Regional Standard	Regional Reliability Standards - PRC-006-NPCC-1 - Automatic Underfrequency Load Shedding	PRC-006-NPCC-1		1/10/11	2/24/11	
7.	Project 2007-07	Project 2007-07 - Vegetation Management - FAC-003	FAC-003-2		1/27/11	2/28/11	Yes 2/28/11
8.	N/A	CAN-0017--Draft CAN-0017 CIP-007 R5 System Access and Password Controls	CAN-0017 CIP-007, R5		2/11/11	3/4/11	Yes 3/4/11
9.	Project 2007-12	Project 2007-12 - Frequency Response	BAL-003-1		2/4/11	3/7/11	Yes 3/7/11
10.	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001, COM-002, IRO-001, and IRO-014	COM-001 COM-002 IRO-001 IRO-014		1/18/11	3/7/11	Yes 3/7/11
11.	NERC RoP	Proposed Changes to Rules of Procedure to Add Section 1700 - Challenges to Determinations	RoP Section 1700		2/14/11	3/7/11	Yes 3/7/11
12.	Project 2009-02	Project 2009-02 - Real-time Reliability Monitoring and Analysis Capabilities	Concept White Paper		2/16/11	4/4/11	Yes 4/4/11
13.	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface	Various BAL, CIP, EOP, FAC, IRO, MOD, PER, PRC, TOP, and VAR Standards		3/4/11	4/4/11	Yes 4/4/11

RSC Meeting #17-4, Agenda Item 6.3: Comment History

(As of 10/4/2017)

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	

RSC Meeting #17-4, Agenda Item 6.3: Comment History

(As of 10/4/2017)

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

RSC Meeting #17-4, Agenda Item 6.3: Comment History

(As of 10/4/2017)

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	

RSC Meeting #17-4, Agenda Item 6.3: Comment History

(As of 10/4/2017)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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	

RSC Meeting #17-4, Agenda Item 6.3: Comment History

(As of 10/4/2017)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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

RSC Meeting #17-4, Agenda Item 6.3: Comment History

(As of 10/4/2017)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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

RSC Meeting #17-4, Agenda Item 6.3: Comment History

(As of 10/4/2017)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
			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

RSC Meeting #17-4, Agenda Item 6.3: Comment History

(As of 10/4/2017)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
99.	N/A	Standard Processes Manual Revisions to Implement SPIG Recommendations	SPIG Reco		6/20/12	7/19/12	Yes 7/19/12
100.	Project 2012-INT-02	Project 2012-INT-02 - Interpretation of TPL-003-0a and TPL-004-0 for System Protection and Control Subcommittee	- Interpretation of TPL-003-0a and TPL-004-0		6/20/12	7/20/12	Yes 7/19/12
101.	Project 2012-INT-05	Interpretation of 2012-INT-05 - Interpretation of CIP-002-3 for OGE	Interpretation of CIP-002-3		6/27/12	7/27/12	Yes 7/27/12
102.	Project 2011-INT-02	Project 2011-INT-02 - Rapid Revision to Address Interpretation of VAR-002 for Constellation	Rapid Revision to VAR-002		7/18/12	7/27/12	Yes 7/26/12
103.	Project 2010-INT-01	Project 2010-INT-01 - Rapid Revision of TOP-006 for FMPP	Rapid Revision of TOP-006		6/14/12	7/30/12	Yes 7/27/12
104.	Project 2012-08.1	Project 2012-08.1 - Phase 1 of Glossary Updates: Statutory Definitions	Glossary of Terms		6/19/12	8/2/12	Yes 8/2/12
105.	N/A	Reliability Guideline: System Operator Verbal Communications – Current Industry Practices	System Operator Verbal Communications		6/26/12	8/10/12	Yes 8/9/12
106.	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	PRC-005-2		7/27/12	8/27/12	Yes 8/27/12
107.	Project 2010-11	Project 2010-11 - TPL Table 1 Order TPL-002-1b, footnote ‘b’ and TPL-001-3, footnote 12	TPL-002-1b, footnote ‘b’ and TPL-001-3, footnote 12		7/31/12	8/29/12	Yes 8/29/12
108.	Project 2006-02	Project 2006-02 - Assess Transmission and Future Needs			7/31/12	8/30/12	
109.	Project 2009-19	Project 2009-19 – Interpretation of BAL-002 by NWPP Reserve Sharing Group			7/25/12	9/4/12	
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

RSC Meeting #17-4, Agenda Item 6.3: Comment History

(As of 10/4/2017)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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	

RSC Meeting #17-4, Agenda Item 6.3: Comment History

(As of 10/4/2017)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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

RSC Meeting #17-4, Agenda Item 6.3: Comment History

(As of 10/4/2017)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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

RSC Meeting #17-4, Agenda Item 6.3: Comment History

(As of 10/4/2017)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
155.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	BES Definition		5/29/13	7/12/13	Yes 7/12/13
156.	TRE Regional Standard	Regional Reliability Standard - BAL-001-TRE-01	BAL-001-TRE-01		5/31/13	7/15/13	
157.	N/A	NPCC Regional Standards Process Manual	NPCC RSPM		6/06/13	7/22/13	
158.	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-003	COM-003-1		6/20/13	7/19/13	Yes 7/19/13
159.	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-025	PRC-025-1		6/20/13	7/19/13	Yes 7/19/13
160.	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-023	PRC-023-3	Formal	6/20/13	8/05/13	Yes 8/5/13
161.	N/A	SPP RE Regional Standards Process Manual	SPP RSPM		6/26/13	8/09/13	
162.	Project 2013-03	Project 2013-03 - Geomagnetic Disturbance Mitigation	EOP-010-1	Formal	6/27/13	8/12/13	Yes 8/12/13
163.	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Reclosing Relays) - PRC-005	PRC-005-3	Formal	7/10/13	8/23/13	Yes 8/23/13
164.	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards	INT-004-3 INT-006-4 INT-009-2 INT-010-2 INT-011-1	Informal	7/25/13	8/23/13	Yes 8/23/13
165.	Project 2012-05	Project 2012-05 ATC Revisions (MOD A) - MOD-001-2	MOD-001-2	Formal	7/11/13	8/26/13	Yes 8/26/13
166.	Project 2010-01	Project 2010-01 - Training - PER-005-2	PER-005-2	Formal	7/19/13	9/03/13	Yes 9/3/13
167.	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4, VAR-002-3	VAR-001-4 VAR-002-3	Formal	7/19/13	9/03/13	Yes 9/3/13
168	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-032-1, MOD-033-1	MOD-032-1 MOD-033-1	Formal	7/22/13	9/04/13	Yes 9/4/13

RSC Meeting #17-4, Agenda Item 6.3: Comment History

(As of 10/4/2017)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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

RSC Meeting #17-4, Agenda Item 6.3: Comment History

(As of 10/4/2017)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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

RSC Meeting #17-4, Agenda Item 6.3: Comment History

(As of 10/4/2017)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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

RSC Meeting #17-4, Agenda Item 6.3: Comment History

(As of 10/4/2017)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
213	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	PRC-005-2(X) PRC-005-3(X) PRC-005-X(X) VAR-002-2b(X) VAR-002-4	Formal	04/17/14	05/05/14	Yes 5/5/14
214	Project 2010-02	Project 2010-02 – Connecting New Facilities to the Grid	FAC-001-1 FAC-002-1	Formal	04/01/14	05/15/14	Yes 5/15/14
215	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation	TPL-007-1	Informal	04/22/14	05/21/14	Yes 5/21/14
216	Project 2012-13	Project 2012-13 Nuclear Plant Interface Coordination	NUC-001-3	Formal	04/08/14	05/22/14	Yes 5/22/14
217	Project 2007-17.3	Project 2007-17.3 Protection System Maintenance and Testing – Phase 3 (Sudden Pressure Relays)	PRC-005-X	Formal	04/17/14	06/03/14	Yes 6/3/14
218	Project 2010-13.3	Project 2010-13.3 Relay Loadability: Stable Power Swings	PRC-026-1	Formal	04/25/14	06/09/14	Yes 6/9/14
219	Project 2007-11	Project 2007-11 Disturbance Monitoring	PRC-002-2	Formal	05/09/14	06/25/14	Yes 6/25/14
221	Project 2008-02	Project 2008-02 Undervoltage Load Shedding and Underfrequency Load Shedding	PRC-010 PRC-020 PRC-021 PRC-022	Informal	05/23/14	06/23/14	Yes 6/23/14
222	Project 2010-05-1	Project 2010-05-1 Protection System – Phase 1 – Misoperations	PRC-004	Formal	05/16/14	07/09/14	Yes 7/9/14
223	Project 2014-03	Project 2014-03 Revisions to TOP-IRO Reliability Standards	TOP-001-3 TOP-002-4 TOP-003-3 IRO-001-4 IRO-002-4 IRO-008-2 IRO-010-2 IRO-014-3 IRO-017-1	Formal	05/19/14	07/02/14	Yes 7/2/14
224	Project 2014-02	Project 2014-02 CIP Version 5 Revisions – 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

RSC Meeting #17-4, Agenda Item 6.3: Comment History

(As of 10/4/2017)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
		Development Plan					
226	2010-05.2	Project 2010-05.2 - Phase 2 of Protection Systems - Revised Definition of Special Protection System	SPS Definition	Formal	7/16/14	7/25/14	Yes 7/25/14
227	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	PRC-005-2(X) PRC-005-3(X) PRC-005-X(X) VAR-002-2b(X) VAR-002-4	Formal	06/12/14	7/29/14	Yes 7/29/14
228	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation	TPL-007-1	Formal	06/13/14	07/30/14	Yes 7/30/14
229	Project 2008-02	Project 2008-02 Undervoltage Load Shedding and Underfrequency Load Shedding	PRC-010 PRC-020 PRC-021 PRC-022	Formal	06/23/14	08/8/14	Yes 8/6/14
230	Project 2010-14-2	Project 2010-14-2 Balancing Authority Reliability-based Control Standard Authorization Request for BAL-005 and BAL-006	BAL-005 BAL-006	Informal	07/16/14	08/14/14	Yes 8/12/14
231	Project 2009-03	Project 2009-03 Emergency Operations – EOP-011-1	EOP-011-1	Formal	07/2/14	08/15/14	Yes 8/13/14
232	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	PRC-004-2.1a(X) PRC-004-3(X)	Formal	07/10/14	08/26/14	Yes 8/25/14
233	Project 2007-17.3	Project 2007-17.3 Protection System Maintenance and Testing – Phase 3 (Sudden Pressure Relays) – PRC-005-X	PRC-005-X	Formal	07/30/14	09/12/14	Yes 9/12/14
234	Project 2014-03	Project 2014-03 Revisions to TOP-IRO Reliability Standards	TOP-001-3 TOP-002-4 TOP-003-3 IRO-001-4 IRO-002-4 IRO-008-2 IRO-010-2 IRO-014-3 IRO-017-1	Formal	08/6/14	09/19/14	Yes 9/22/14
235	Project 2010-14.1	Project 2010-14.1 Balancing Authority Reliability-based Control	BAL-002-2	Formal	08/19/14	10/03/14	Yes 10/2/14

RSC Meeting #17-4, Agenda Item 6.3: Comment History

(As of 10/4/2017)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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

RSC Meeting #17-4, Agenda Item 6.3: Comment History

(As of 10/4/2017)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
		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

RSC Meeting #17-4, Agenda Item 6.3: Comment History

(As of 10/4/2017)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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

RSC Meeting #17-4, Agenda Item 6.3: Comment History

(As of 10/4/2017)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
		based Controls					
282	Project 2010-14.2.2	Phase 2 of Balancing Authority Reliability-based Controls: Time Error Correction	BAL-004-0	Survey	8/12/15	8/25/15	Yes 8/25/15
283	Project 2007-06.2	Phase 2 of System Protection Coordination	TOP-009-1	Formal	7/29/15	9/11/15	Yes 9/11/15
284	Project 2007-06	System Protection Coordination	PRC-027-1	Formal	7/29/15	9/11/15	Yes 9/11/15
285	Project 2010-14.2.1	Phase 2 of Balancing Authority Reliability-based Controls	BAL-005-1 BAL-006-3	Formal	7/30/15	9/14/15	Yes 9/14/15
286	Project 2007-17.4	PRC-005 FERC Order No. 803 Directive	PRC-005-6	Formal	7/30/15	9/16/15	Yes 9/16/15
287	Project 2010-04.1	MOD-031 FERC Order No. 804 Directives	MOD-031-2	Formal	7/31/15	9/18/15	Yes 9/18/15
288	Project 2015-09	Establish and Communicate System Operating Limits	FAC-010-3 FAC-011-3 FAC-014-2	Informal	8/20/15	9/21/15	Yes 9/21/15
289	Project 2010-07.1	Vegetation Management	FAC-003-3	Informal	8/24/15	9/28/15	Yes 9/28/15
290	Project 2010-05.3	Phase 3 of Protection Systems: Remedial Action Schemes	PRC-012-2	Formal	8/20/15	10/5/15	Yes 10/5/15
291	Project 2009-02	Real-time Reliability Monitoring and Analysis Capabilities	IRO-018-1 TOP-010-1	Formal	9/24/15	11/9/15	Yes 11/9/15
292	Project 2010-14.2.2	Phase 2 of Balancing Authority Reliability-based Controls	BAL-004-0	Formal	9/24/15	11/12/15	Yes 11/12/15
293	Project 2015-07	Internal Communications Capabilities	COM-001-3	Formal	9/25/15	11/16/15	Yes 11/16/15
294	Project 2007-06.2	Phase 2 of System Protection Coordination	TOP-009-1	Formal	10/6/15	11/19/15	Yes 11/19/15
295	Project 2010-07.1	Vegetation Management	FAC-003-3	Formal	10/30/15	12/16/15	Yes 12/16/15
296	Project 2015-10	Single Points of Failure SAR	TPL-001	Informal	11/12/15	12/17/15	Yes 12/17/15
297	Project 2010-05.3	Phase 3 of Protection Systems RAS	PRC-012-2	Formal	11/25/15	1/8/16	Yes 1/8/16
298	Project 2010-14.2.1	Phase 2 of Balancing Authority Reliability-based Controls	BAL-005-1 FAC-001-3 BAL-006-2	Formal	12/31/15	1/11/16	Yes 1/11/16
299	Project 2009-02	Real-time Reliability Monitoring and Analysis Capabilities	IRO-018-1 TOP-010-1	Formal	12/10/15	1/25/16	Yes 1/25/16
300	Project 2016-01	Modifications to TOP and IRO Standards	SAR	Informal	1/22/16	2/22/16	Yes 2/22/16
301	Project 2010-05.3	Phase 3 of Protection Systems RAS	PRC-012-2	Formal	2/3/16	3/18/16	Yes 3/18/16
302	Project	Modifications to CIP	SAR	Informal	3/23/16	4/21/16	Yes

RSC Meeting #17-4, Agenda Item 6.3: Comment History

(As of 10/4/2017)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
	2016-02	Standards					4/21/16
303	Project 2007-06.2	Phase 2 of System Protection Coordination	PER-006-1 & Two Definitions	Formal	3/10/16	4/25/16	Yes 4/25/16
304	Project 2015-07	Internal Communications Capabilities	COM-001-3	Formal	3/23/16	5/9/16	Yes 5/6/16
305	CEP	Cost Effectiveness Pilot	TPL-001-4	Informal	4/27/16	5/26/16	Yes 5/26/16
306	Project 2013-03	Geomagnetic Disturbance Mitigation Revised White Papers	SAR	Informal	5/12/16	6/13/16	Yes 6/13/16
307	Project 2015-10	Single Points of Failure	SAR	Informal	5/26/16	6/24/16	Yes 6/24/16
308	Project 2016-02	Modifications to CIP Standards	SAR	Informal	6/1/16	6/30/16	Yes 6/30/16
309	Draft 2017-2019	Reliability Standards Development Plan	RSDP	Informal	6/20/16	7/19/16	Yes 7/19/16
310	EPR	Enhanced Periodic Review Standing Review Team	Standards Grading	Informal	6/30/16	8/1/16	Yes 8/1/16
311	Project 2016-01	Modifications to TOP and IRO Standards	IRO-002-5 TOP-001-4	Formal	6/20/16	8/3/16	Yes 8/3/16
312	Project 2015-09	Establish and Communicate System Operating Limits	FAC-014-3	Formal	7/14/16	8/12/16	Yes 8/12/16
313	Project 2015-09	Establish and Communicate System Operating Limits	FAC-011-4	Formal	7/14/16	8/12/16	Yes 8/12/16
314	Project 2015-08	Emergency Operations	EOP-005-3 EOP-006-3 EOP-008-2	Formal	6/30/16	8/15/16	Yes 8/15/16
315	Project 2016-02	Modifications to CIP Standards	CIP-003-7	Formal	7/21/16	9/6/16	Yes 9/6/16
316	FMAG	Functional Model Advisory Group	Reliability Functional Model and Technical Document	Informal	7/21/16	9/7/16	Yes 9/7/16
317	Project 2015-08	Emergency Operations	EOP-004-4	Formal	7/25/16	9/8/16	Yes 9/8/16
318	Project 2015-INT-01	Interpretation of CIP-002-5.1 for Energy Sector Security Consortium (EnergySec)	CIP-002-5.1	Formal	7/27/16	9/12/16	Yes 9/12/16
319	Project 2016-01	Modifications to TOP and IRO Standards SAR	TOP-001-3 IRO-002-4	Formal	8/31/16	10/17/16	Yes 10/14/16
320	Project 2016-04	Modifications to PRC-025-1 SAR	PRC-025-1	Formal	9/16/16	10/18/16	Yes 10/18/16
321	Project 2016-03	Cyber Security Supply Chain Management	SAR	Informal	10/20/16	11/18/16	Yes 11/18/16
322	Project	Modifications of CIP	CIP-003-TCA	Informal	11/1/16	11/18/16	Yes

RSC Meeting #17-4, Agenda Item 6.3: Comment History

(As of 10/4/2017)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
	2016-02	Standards					11/18/16
323	Project 2016-02	Modifications of CIP Standards	CIP-003-7	Formal	11/23/16	12/5/16	Yes 12/5/16
324	Project 2015-08	Emergency Operations	EOP-005-3 EOP-006-3	Formal	10/26/16	12/9/16	Yes 12/9/16
325	Project 2015-08	Emergency Operations	EOP-004-4	Formal	11/18/16	1/6/17	Yes 1/6/17
326	Project 2013-03	Geomagnetic Disturbance Mitigation	SAR	Informal	12/16/16	1/20/17	Yes 1/20/17
327	Project 2016-02	Modifications of CIP Standards	CIP-003-7(i)	Formal	12/12/16	1/25/17	Yes 1/25/17
328	Project 2016-EPR-01	Enhanced Periodic Review of Personnel Performance, Training and Qualifications Standard (PER)	PER-001-0.2 PER-003-1 PER-004-2	Formal	1/10/17	2/23/17	Yes 2/23/17
329	Project 2016-03	Cyber Security Supply Chain Risk Management	CIP-013-1	Formal	1/19/17	3/6/17	Yes 3/6/17
330	Project 2016-04	Modifications to PRC-025-1	SAR	Informal	3/20/17	4/3/17	Yes 4/3/17
331	Project 2016-02	Modifications to CIP Standard	Virtualization	Informal	3/14/17	4/11/17	Yes 4/11/17
332	Project 2016-02	Modifications to CIP Standard	TOCC	Informal	3/14/17	4/11/17	Yes 4/11/17
333	Project 2016-EPR-02	Enhanced Periodic Review of Voltage and Reactive (VAR) Standards	VAR-001-4.1	Formal	2/28/17	4/13/17	Yes 4/13/17
334	Project 2016-EPR-02	Enhanced Periodic Review of Voltage and Reactive (VAR) Standards	VAR-002-4	Formal	2/28/17	4/13/17	Yes 4/13/17
335	SPM	Revisions to the NERC Standard Processes Manual	SPM	Formal	3/20/17	5/3/17	Yes 5/3/17
336	Project 2015-10	Single Points of Failure	TPL-001-5	Informal	4/25/17	5/24/17	Yes 5/24/17
337	Project 2016-03	Cyber Security Supply Chain Risk Management	CIP-005-6 CIP-010-3 CIP-013-1	Formal	5/2/17	6/15/17	Yes 6/15/17
338	Project 2017-01	Modifications to BAL-003-1.1 SAR	BAL-003-1.1	Formal	6/19/17	7/18/17	Yes 7/18/17
339	Project 2017-06	Modifications to BAL-002-2 SAR	BAL-002-2	Informal	6/20/17	7/20/17	Yes 7/20/17
340	Project 2017-02	Modifications to Personnel Performance, Training and Qualifications Standards	PER-003-1 PER-004-2	Informal	6/21/17	7/24/17	Yes 7/24/17
341	2018-2010	Reliability Standards Development Plan		Formal	6/22/17	7/25/17	Yes 7/26/17

RSC Meeting #17-4, Agenda Item 6.3: Comment History

(As of 10/4/2017)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
342	Standards Grading	Periodic Review Standing Review Team	Standards Grading	Informal	6/19/17	8/2/17	Yes 8/2/17
343	Project 2013-03	Geomagnetic Disturbance Mitigation	TPL-007-2	Formal	6/28/17	8/11/17	Yes 8/11/17
344	Project 2017-07	Alignment with Registration	Registration	Formal	8/1/17	8/30/17	Yes 8/30/17
345	Project 2017-07	Alignment with Registration	MOD-032-1 SAR	Formal	8/1/17	8/30/17	Yes 8/30/17
346	Reliability Guideline	Area Control Error Diversity Interchange Process	ACE Process	Formal	7/18/17	8/31/17	Yes 8/31/17
347	Project 2016-04	Modifications to PRC-025-1	PRC-025-2	Formal	7/25/17	9/7/17	Yes 9/7/17
348	Project 2016-02	Modifications to CIP Standard	CIP-012-1	Formal	7/27/17	9/11/17	Yes 9/11/17
349	Project 2016-02	Modifications to CIP Standard	Technical Rationale and Justification for CIP-012-1	Informal	8/14/17	9/12/17	Yes 9/12/17
350	Project 2016-02	Modifications to CIP Standard	Definition of Control Center	Informal	8/14/17	9/12/17	Yes 9/12/17

Note: RSC past comment forms are posted on the NPCC Website under "Standards - Regional Standards Comments."

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

March 30, 2017

NPCC Full and General Members:

The ballot for approval of the revisions to the Quebec Variance in PRC-006-3 *Automatic Underfrequency Load Shedding* closed at 23:59 on March 24, 2017.

The results of the ballot were as follows:

Quorum: 79.59% of the Total Registered
Approval: 89.74%

One negative ballot was received without comments, therefore in accordance with the NPCC Standard Processes Manual, a recommendation for final Regional approval will be sent to the NPCC Board of Directors for consideration at their meeting on May 3, 2017.

Contingent upon the approval of the NPCC BOD, the proposal to adopt the revised variance in PRC-006-3 will be posted for a 45 day comment period by NERC, specifically related to NPCC's Standard development process. Upon receipt of any industry comments, responses to those comments will be posted on the NERC website. NERC will then submit the proposed standard, along with their endorsement, to the NERC Board of Trustees (BOT) for adoption. Upon adoption by the BOT, the standard will then be filed by NERC Legal with the FERC and applicable provincial authorities.

Voting was conducted electronically and the full ballot record may be viewed at:

https://www.npcc.org/Standards/SitePages/DevStandardDetail.aspx?DevDocumentId=123

Thank you for your participation.

Ruida Shu
Northeast Power Coordinating Council, Inc.
Senior Engineer, Reliability Standards and Criteria
Main: 212-840-1070
Direct: 917-934-7976
Fax: 212-302-2782
Email: rshu@npcc.org

	1. Determine Quorum				2. Vote/Ballot Recording		
NPCC Registered Members		**In Attendance**	**By Proxy**		**Affirmative**	**Negative**	**Abstain**
		(denote w/ 1)	(denote w/ 1)		(denote w/ 1)	(denote w/ 1)	(denote w/ 1)
Sector 1, Transmission Owners	**18**	**16**	**0**		**16**	**0**	**0**
Central Hudson Gas and Electric Corporation	1	1			1		
Central Maine Power Company	1	1			1		
Consolidated Edison Company of New York, Inc.	1	1			1		
Emera Maine	1						
Eversource Energy	1	1			1		
Hydro One Inc	1	1			1		
Hydro-Quebec TransEnergie	1	1			1		
Long Island Power Authority	1	1			1		
National Grid	1	1			1		
New Brunswick Power Corporation	1	1			1		
New Hampshire Transmission, LLC	1	1			1		
New York Power Authority	1	1			1		
New York State Electric & Gas Corporation	1						
Nova Scotia Power Inc.	1	1			1		
Orange and Rockland Utilities Inc	1	1			1		
Rochester Gas & Electric Corporation	1	1			1		
The United Illuminating Company	1	1			1		
Vermont Transco	1	1			1		

	1. Determine Quorum				2. Vote/Ballot Recording		
NPCC Registered Members		**In Attendance**	**By Proxy**		**Affirmative**	**Negative**	**Abstain**
		(denote w/ 1)	(denote w/ 1)		(denote w/ 1)	(denote w/ 1)	(denote w/ 1)
Sector 2, Reliability Coordinators	**5**	**5**	**0**		**5**	**0**	**0**
Hydro-Quebec TransEnergie	1	1			1		
Independent Electricity System Operator	1	1			1		
ISO-New England, Inc.	1	1			1		
New Brunswick Power Corporation	1	1			1		
New York Independent System Operator	1	1			1		

	1. Determine Quorum				2. Vote/Ballot Recording		
NPCC Registered Members		**In Attendance**	**By Proxy**		**Affirmative**	**Negative**	**Abstain**
		(denote w/ 1)	(denote w/ 1)		(denote w/ 1)	(denote w/ 1)	(denote w/ 1)
Sector 3, TDUs, Dist. And LSE	**20**	**16**	**0**		**14**	**0**	**2**
Braintree Electric Light Department	1	1			1		
Consolidated Edison Company of New York, Inc.	1	1			1		
Eversource Energy	1	1			1		
Groton Electric Light	1	1			1		
Hingham Municipal Lighting Plant	1	1			1		
Hydro One Inc	1	1			1		
Hydro Quebec Distribution	1	1			1		
Ipswich Municipal Light Department	1	1					1
Long Island Power Authority	1	1			1		
Marblehead Municipal Light Department	1	1			1		
National Grid USA	1	1			1		
New York Power Authority	1	1			1		
Orange and Rockland Utilities, Inc	1	1			1		
Princeton Municipal Light Department	1	1			1		
Shrewsbury Electric & Cable Operations	1	1			1		
Sterling Municipal Light Department	1						
Toronto Hydro Electric System Ltd.	1						
Vermont Electric Cooperative, Inc.	1						
Wakefield Municipal Gas and Light Department	1	1					1
Westfield Gas & Electric Light Department	1						

	1. Determine Quorum				2. Vote/Ballot Recording		
NPCC Registered Members		**In Attendance**	**By Proxy**		**Affirmative**	**Negative**	**Abstain**
		(denote w/ 1)	(denote w/ 1)		(denote w/ 1)	(denote w/ 1)	(denote w/ 1)
Sector 4, Generator Owners	**21**	**15**	**0**		**13**	**1**	**1**
Consolidated Edison Company of New York, Inc.	1	1			1		
Covanta Energy	1						
Dominion Resources, Inc.	1	1			1		
Dynegy, Inc.	1	1				1	
Entergy Nuclear Northeast, Inc	1	1			1		
Eversouce Energy	1	1			1		
Exelon Generation Company, LLC	1						
First Wind Operations & Maintenance	1						
International Power America	1						
Long Island Power Authority	1	1			1		
Massachusetts Municipal Wholesale Electric Company	1	1			1		
New York Power Authority	1	1			1		
NextEra Energy Resources, LLC	1	1			1		
NRG Energy Inc.	1	1			1		
Nova Scotia Power Inc.	1	1					1
Ontario Power Generation Inc.	1	1			1		
PSEG Fossil LLC	1						
Talen Energy Supply, LLC	1	1			1		
TransCanada	1	1			1		
Eastern Generation LLC	1						
Wheelabrator Westchester LP	1	1			1		

	1. Determine Quorum				2. Vote/Ballot Recording		
NPCC Registered Members		**In Attendance**	**By Proxy**		**Affirmative**	**Negative**	**Abstain**
		(denote w/ 1)	(denote w/ 1)		(denote w/ 1)	(denote w/ 1)	(denote w/ 1)
Sector 5, Marketers, Brokers, Aggragators	**13**	**10**	**0**		**9**	**0**	**1**
Brookfield Power Corporation	1	1			1		
Consolidated Edison Company of New York, Inc.	1	1			1		
Consolidated Edison Energy/Development	1	1			1		
Constellation New Energy, Inc.	1						
HQ Energy Marketing Inc.	1	1			1		
H.Q. Energy Services (U.S.) Inc.	1	1			1		
Long Island Power Authority	1						
Massachusetts Municipal Wholesale Electric Company	1	1			1		
Nalcor Energy	1	1					1
New York Power Authority	1	1			1		
Shell Energy North America	1	1			1		
Utility Services Inc.	1	1			1		
Windy Bay Power, LLC	1						

	1. Determine Quorum			2. Vote/Ballot Recording		
NPCC Registered Members	**In Attendance**	**By Proxy**		**Affirmative**	**Negative**	**Abstain**
	(denote w/ 1)	(denote w/ 1)		(denote w/ 1)	(denote w/ 1)	(denote w/ 1)
Sector 6, State and Provincial Reg. and Govt. Authorities	**7**	**6**	**0**	**6**	**0**	**0**
Long Island Power Authority	1	1		1		
Maine Public Utilities Commission	1	1		1		
Massachusetts Attorney General	1	1		1		
New Hampshire Public Utilities Commission	1	1		1		
New York Power Authority	1	1		1		
New York State Department of Public Service	1	1		1		
Vermont Department of Public Service	1					

	1. Determine Quorum				2. Vote/Ballot Recording		
NPCC Registered Members		**In Attendance**	**By Proxy**		**Affirmative**	**Negative**	**Abstain**
		(denote w/ 1)	(denote w/ 1)		(denote w/ 1)	(denote w/ 1)	(denote w/ 1)
Sector 7, Sub Regional Rel. Councils, REs and Others	**14**	**10**	**0**		**7**	**0**	**3**
4g Technologies, LP	1						
Ascendant Energy Solutions, Inc.	1	1			1		
Energy Sector Security Consortium, Inc.	1						
ERLPhase Power Technologies	1	1			1		
International Business Machines Corporation	1						
McCoy Power Consultants, Inc.	1	1					1
Network & Security Technologies, Inc.	1	1					1
New York State Reliability Council, LLC	1	1			1		
Oxbow-Sherman Energy, LLC	1	1			1		
PLM, Inc.	1	1					1
Preti, Flaherty, Beliveau, and Pachios, LLP.	1	1			1		
Proven Compliance Solutions, Inc.	1	1			1		
SGC Engineering, LLC	1	1			1		
VIASYN, Inc.	1						

Determine Electronic Quorum

Sector	Sector Name	Total Registered	In Attendance	By Proxy	Total Represented	Sector % Attending
1	**Transmission Owners**	18	16	0	16	0.89
2	**Reliability Coordinators**	5	5	0	5	1.00
3	**TDUs, Dist. And LSE**	20	16	0	16	0.80
4	**Generator Owners**	21	15	0	15	0.71
5	**Marketers, Brokers, Aggragators**	13	10	0	10	0.77
6	**Customers- large and small**	7	6	0	6	0.86
7	**State and Provincial Reg. and Govt. Authorities**	14	10	0	10	0.71
		98	78	0	78	

Electronic Vote Quorum= at least 2/3 of the Total Registered

Quorum Present? **YES**

Determine if Motion or Item Passes

Sector	Sector Name	Total	Sector %	Affirmative		Negative		Abstain	Votes Cast	Sector has
		Registered	Attending	# of Votes	Fraction	# of Votes	Fraction	# of Votes	Total (- Abstentions)	Voted(1-Y, 0-N)
1	**Transmission Owners**	18	0.89	16	1.000	0	0.000	0	16	1
2	**Reliability Coordinators**	5	1.00	5	1.000	0	0.000	0	5	1
3	**TDUs, Dist. And LSE**	20	0.80	14	1.000	0	0.000	2	14	1
4	**Generator Owners**	21	0.71	13	0.929	1	0.071	1	14	1
5	**Marketers, Brokers, Aggragators**	13	0.77	9	1.000	0	0.000	1	9	1
6	**Customers- large and small**	7	0.86	6	1.000	0	0.000	0	6	1
7	**State and Provincial Reg. and Govt. Authorities**	14	0.71	7	1.000	0	0.000	3	7	1
	Totals	98		70	6.929	1	0.071	7	71	7

Sum of Affirmative/Number of Sectors that Voted
MUST BE AT LEAST 2/3 to pass

0.990

Did MOTION PASS?

PASS

A. Introduction

1. **Title:** **Automatic Underfrequency Load Shedding**

2. **Number:** PRC-006-NPCC-~~2~~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.~~ The NPCC Automatic Underfrequency Load Shedding (UFLS) regional S~~s~~tandard establishes more stringent and specific NPCC UFLS program requirements to ensure that declining frequency is arrested and recovered in accordance with established NPCC performance requirements stipulated in this document.

4. **Applicability:**

   4.1. Generator Owner

   4.2. Planning Coordinator

   ~~4.2.~~ Distribution Providers that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program.

   4.3.

   4.4. Transmission Owners that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program.

~~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 t~~The first day of the first calendar quarter following applicable governmental and regulatory approvals. ~~but no earlier than April 1, 2017.~~

B. Requirements

~~R1~~ R1 ~~NPCC Under frequency Load Shedding Program - More Stringent Criteria~~

Formatted: Font: Not Bold

Commented [DML1]: Dan to move to "purpose" section

Formatted: No bullets or numbering

Commented [RS2]: National Grid:
Should the Applicability List re-ordered to list:
4.1 Planning Coordinator
4.2 Distribution Provider
4.3 Transmission Owner
4.4 Generation Owner
The current NERC guidance regarding the applicability ordering.

Formatted: Indent: First line: 0"

Commented [RS3]: National Grid:
Thought standards now need an Implementation Plan and should say "See Implementation Plan"

~~The NPCC underfrequency Criteria are in addition to, or more stringent or more specific than the NERC PRC Standard on UFLS, or any Regional Reliability standard requirements.~~

~~The intent of the NPCC automatic Under frequency Load Shedding program is to ensure that declining frequency is arrested and recovered in accordance with established NPCC performance requirements stipulated in this document.~~

Commented [DML4]: Dan to move to "purpose" section

~~Each Planning Coordinator shall design a UFLS program 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).~~

Rationale for Requirement R1: ~~Attachment 1~~Figure 1 of this document shows the NPCC underfrequency criteria for the Eastern ~~I~~interconnection portion of NPCC. Note that ~~Attachment 1~~Figure 1 also shows the NERC criteria as defined in the NERC PRC Standard on UFLS.

Formatted Table

R1. Each Planning Coordinator in the Eastern Interconnection portion of NPCC shall design an UFLS program having performance characteristics that prevents the frequency from remaining below 59.5 Hz for greater than 30 seconds in accordance with Figure 1.

Formatted: Font: Italic

~~*R1.1 Frequency decline is arrested at no less than 58.0 Hz for the portions of NPCC in the Eastern Interconnection.*~~

~~*R1.2 Frequency does not remain below 58.5 Hz for greater than 10 seconds, and does not remain below 59.5 Hz for greater than 30 seconds.*~~

~~*[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*~~

Formatted: Normal, Indent: Left: 0", Hanging: 0.25"

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.

Formatted: Font: 12 pt

~~Attachment 1 of this document shows the NPCC underfrequency criteria for the eastern interconnection portion of NPCC. Note that Attachment 1 also shows the NERC criteria as defined in the NERC PRC Standard on UFLS. The Section below need to be move to Rationale Box:~~

~~"Attachment 1 of this document shows the NPCC underfrequency criteria for the eastern interconnection portion of NPCC. Note that Attachment 1 also shows the NERC criteria as defined in the NERC PRC Standard on UFLS."~~

Formatted: Indent: Left: 0", Hanging: 0.63"

R2. ~~-~~Each Planning Coordinator shall provide UFLS island boundaries, as identified per the NERC PRC Standard on UFLS, ~~-~~ to Distribution ~~p~~Providers, Generator Owners, and

Transmission O~~o~~wners within 30 days of receipt of a ~~of a~~ request. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*

M2. ~~—~~Each Planning Coordinator shall have evidence such as dated documentation that demonstrates that it meets requirement R2.

~~**Do not change language of existing R2 but it becomes:**~~

~~**R3.** 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]~~

~~**Rationale for Requirement R3:** Demonstrate to the Regional Entity, via system studies, that the UFLS program will not meet performance requirements if all non-BES generators identified in R3.1 trip above underfrequency trip threshold curve in Figure 1~~

R3. ~~-~~ ~~—~~Each Planning Coordinator shall, within 30 days of completion of its UFLS system studies, identify to the Regional Entity all non-BES generation facilities, within its Planning Coordinator Area, that must not trip above the appropriate generator underfrequency trip threshold curve in Figure 2 in order to support acceptable UFLS program performance.

~~*R3.2 Demonstrate to the Regional Entity, via system studies, that the UFLS program will not meet performance requirements if all non-BES generators identified in R3.1 trip above underfrequency trip threshold curve in Figure 1.*~~

[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

M3. Each Planning Coordinator shall have evidence such as dated documentation that demonstrates that it meets Requirement 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]~~

Formatted: Font: Italic

Formatted: Font: 12 pt

Commented [DML5]: R3 language needs to be rewritten so as to clarify intent. Confusing as is.

Formatted: Requirement, Indent: Left: 0", Hanging: 0.31"

Commented [RS6]: From National Grid: Do we still need rationale box if we have this?

Commented [RS7]: National Grid: Appears to be an administrative requirement which would qualify as a "P81" requirement.

Formatted: Font: Italic

Commented [RS8]: Potentially move to Rationale Box or Dean Latulipe find a way to avoid putting it into rationale box and put specifics into the requirement.

Formatted: Font: Italic

Formatted: Font: Italic

Formatted: Font: Not Bold, Italic

Formatted: Indent: First line: 0"

Formatted: Indent: First line: 0"

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. The automatic UFLS program shall be implemented on an island basis for each island identified per the NERC PRC Standard on UFLS. ~~*for its Facilities*~~ *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

4.1. The UFLS program shall be implemented~~-~~ by each Distribution Provider and Transmission Owner according ~~based~~ to~~on~~ the frequency thresholds, ~~total~~ nominal operating times and load shedding amounts specified in Attachment C, Tables 1 through 3.~~,~~

4.2. Alternatively, the program can be implemented ~~or shall~~ collectively ~~implement , by mutual agreement~~ by ~~with~~ multiple ~~one or more~~ Distribution Providers or~~and~~ Transmission Owners with less than 100 MW of individual peak net Load, as long they reside in the same UFLS Island identified by the Planning Coordinator per R2. ~~within the same island per identified in, Requirement R1,~~ These multiple Distribution Providers or Transmission owners~~and~~, via mutual agreement, shall act~~ing~~ as a single entity to~~,~~ provide an aggregated automatic UFLS program that sheds their coincident peak aggregated net Load according to~~, based on~~ the frequency thresholds, total nominal operating time and amounts specified in Attachment C, Tables 1 through 3.

~~**4.3.** Whether implemented collectively or individually, the automatic UFLS program shall be implemented on an island basis. Each Distribution Provider and Transmission Owner shall provide the required loadshedding amounts and frequency thresholds specified in the Attachment C, Tables 1 through 3, within each island identified in R2.~~

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 in their respective areas, 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). ~~[Violation Risk Factor: High] [Time Horizon: Long Term Planning]~~

~~**R5.**~~

~~If a Distribution Provider or Transmission Owner cannot meet the tolerances and/or number of stages and frequency set points specified in Attachment C, Tables 1 through 3, such Distribution Provider or Transmission Owner shall: .~~

Formatted: Font: Italic

Formatted: Font: Bold

Formatted: Indent: Left: 0.31", Hanging: 0.31"

Formatted: Font: Bold

Formatted: Font: Bold

Formatted: Indent: Left: 0", First line: 0"

Formatted: Font: (Default) Times New Roman, Bold

Formatted: Indent: Left: 0", Hanging: 0.31"

Formatted: Indent: Left: 0", Hanging: 0.31"

Formatted: Indent: Left: 0", Hanging: 0.31"

Formatted: Font color: Text 1

~~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~~**~~5.1.1.~~** ~~and~~;**~~5.1.2.~~**

~~**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.~~.1

~~**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~~**~~5.3.1.~~**

~~**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.~~.1

~~**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.~~

~~**Rationale for Requirement R6:** Operation of underfrequency relays results directly in load being shed, interrupting service to customers. The security of underfrequency relays against misoperation is therefore paramount. The 100 ms minimum time delay specified in R6 serves to prevent premature activation of these relays during short-lived transient frequency excursions that may occur on a localized basis in the absence of a serious system event wherein UFLS would be appropriate. This intentional delay helps to ensure that the relays activate only for frequency excursions that are due to actual system events that require automatic UFLS to reestablish the balance of generation to load.~~

R5. Each Distribution Provider or Transmission Owner that cannot meet the tolerances and/or number of stages and frequency set points specified in the UFLS Program, shall notify its

Formatted: Indent: Left: 0", Hanging: 0.31"

Formatted: Font: Italic, Font color: Text 1

Formatted: Font: Bold

Formatted: Normal, Indent: Left: 0", Hanging: 0.31", Don't keep with next

Formatted: Font: Bold

Formatted: Font: Bold

Formatted: Font: Bold

Formatted: Indent: Left: 0", Hanging: 0.31"

Formatted: Font: Bold

Formatted: Font: Bold

Formatted: Font: Bold

Formatted: Font: Bold

Formatted: List Paragraph

Formatted: Not Highlight

Formatted: Not Highlight

Formatted: Indent: Left: 0", First line: 0", Tab stops: 0.65", List tab

Formatted: Indent: Left: 0", Hanging: 0.65", Tab stops: 0.65", List tab

Planning Coordinator within 30 days, and: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

5.1. Each Distribution Provider or Transmission Owner applicable to Attachment C, Table 1, within 90 calendar days of informing of its Planning Coordinator that tolerances cannot be met, determine if tolerances can be met through adjustments and notify the Planning Coordinator of the determination and;

5.1.1. If adjustments are possible, make the adjustments within 180 calendar days after determining that adjustments are possible and notify the Planning Coordinator when complete, or;

5.1.2. If adjustments are not possible then provide its Planning Coordinator with a technical study within 180 calendar days 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.

5.2. Each Distribution Provider or Transmission Owner applicable to Attachment C, Table 2 or Table 3, within 90 calendar days after informing the Planning Coordinator, determine if tolerances can be met through adjustments and notify the Planning Coordinator of the determination, and;

5.2.1. If adjustments are possible, within 90 calendar days make the adjustments of determining that adjustments are possible and notify the Planning Coordinator when complete, or;

5.2.2. If adjustments are not possible, then within 90 calendar days 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.

5.3. Each Distribution Provider or Transmission Owner in the Quebec Interconnection, within 90 calendar days after informing the Planning Coordinator, determine if tolerances can be met through adjustments and notify the Planning Coordinator of the determination, and;

5.3.1. If adjustments are possible, within 180 calendar days make the adjustments of determining that adjustments are possible and notify the Planning Coordinator when complete, or;

5.3.2. If adjustments are not possible, then within 90 calendar days 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 the UFLS program.

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.

Formatted: Indent: Left: 1.5", First line: 0"

Formatted: Font: Bold

Rationale for Requirement R6: Operation of underfrequency relays results directly in load being shed, interrupting service to customers. The security of underfrequency relays against misoperation is therefore paramount. The 100 ms minimum time delay specified in R6 serves to prevent premature activation of these relays during short-lived transient frequency excursions that may occur on a localized basis in the absence of a serious system event wherein UFLS would be appropriate. This intentional delay helps to ensure that the relays activate only for frequency excursions that are due to actual system events that require automatic UFLS to reestablish the balance of generation to load.

~~**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]~~

R6.~~7~~ ~~—~~Each Distribution Provider and Transmission Owner shall set each underfrequency relay that is part of its region's UFLS program with a 100 ms~~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]

M6. ~~—~~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 R6.

~~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). **Rationale Box:** Operation of underfrequency relays results directly in load being shed, interrupting service to customers. The security of underfrequency relays against misoperation is therefore paramount. The 100 ms minimum time delay specified in R6 serves to prevent premature activation of these relays during short-lived transient frequency excursions that may occur on a localized basis in the absence of a serious system event wherein UFLS would be appropriate. This intentional delay helps to ensure that the relays activate only for frequency excursions that are due to actual system events that require automatic UFLS to reestablish the balance of generation to load.~~

Formatted: Indent: Left: 0", Hanging: 0.65", Tab stops: 0.65", List tab

Formatted: Indent: Hanging: 0.65", Tab stops: 0.65", List tab

Formatted: Indent: Left: 0", Hanging: 0.25", Tab stops: 0.25", List tab

Formatted: Font: Italic

Formatted: Font: Bold

R7.~~8~~ –Each Planning Coordinator shall develop and review settings for inhibit thresholds at least once per five calendar years (such as but not limited to voltage, current and time) to be utilized within its region's UFLS program.~~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) of UFLS relays to be utilized within its region's UFLS program.~~ *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*

M~~8~~7. — Each Planning Coordinator shall have evidence such as reports, system studies or analysis that demonstrates that it meets Requirement R~~8~~7.

R8.~~9~~ 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]*

M8. Each Planning Coordinator shall provide evidence such as letters, emails, or other dated documentation that demonstrates that it meets Requirement R8.

R9.~~10~~ Each Distribution Provider and Transmission Owner that receives a notification pursuant to Requirement R8 shall develop and submit an implementation plan within 90 days of the request from the Planning Coordinator for approval by the Planning Coordinator. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M9. Each Planning Coordinator shall provide evidence such as letters, emails, or other dated documentation that demonstrates that it meets Requirement R9.

R~~10~~. –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 R~~8~~9. and based on the Planning Coordinator approved implementation plan in accordance with R9. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M10. — Each Distribution Provider and Transmission Owner shall provide evidence such as test reports, data sheets, completed work orders, or other documentation that demonstrates that it meets Requirement R10.

Formatted: Indent: Left: 0", Hanging: 0.31", Space After: 0 pt

Formatted: Font: Italic

Formatted: Font: Bold

Formatted: Indent: Left: 0", Hanging: 0.31", Space Before: 0 pt, After: 0 pt

Formatted: Indent: Left: 0", Hanging: 0.31", Space After: 0 pt

Formatted: Indent: Left: 0", Hanging: 0.31", Space Before: 0 pt, After: 0 pt

Commented [RS9]: National Grid: Suggest to remove "…of the initial determination of those inhibit thresholds and…" My guess is that all the PC's have made their initial determinations and we only need to consider any changes to those thresholds.

Formatted: Font: Italic

Formatted: Indent: Left: 0", First line: 0"

Commented [RS10]: National Grid: Suggestion to re-word. Each Distribution Provider and Transmission Owner that receives a notification pursuant to Requirement R8 shall, develop and submit an implementation plan within 90 days of the request…

Formatted: Font: Italic

Formatted: Font: Italic

Formatted: Tab stops: 0.65", List tab + Not at 0.31"

Formatted: Font: Bold

Formatted: Font color: Text 1

Formatted: Tab stops: 0.65", List tab + Not at 0.31"

Formatted: Font: Italic

Rationale for Requirement R11: It is recognized that, ideally, the amount of load to be shed in each stage of the UFLS program for every entity should perfectly match that prescribed in this Standard universally, for all phases of the load cycle, i.e., seasonal (summer vs. winter), weekly (weekday vs. weekend vs. holidays), daily (morning, noon, and night), etc. for all of the identified islands. Practically, however, this is obviously not possible because the load cycles of the various areas and sub-areas within any given island do not perfectly track the load cycle of the overall island. The UFLS program, on the other hand, is designed based on peak conditions for the overall island. The percentages of actual load shedding that would occur for any conditions other than peak, therefore, can only approximate that prescribed in the Standard. This being said, entities are required by R11 to document measured loads in the UFLS program coincident with their own annual peak, whether or not that peak occurs at the same time or in the same season as the peak of the identified island in which their load resides. Using individual entity peaks vs. overall island peaks provides a consistent approach for accounting purposes among the very entities that are responsible for designing and maintaining their UFLS programs.

~~(The original R9 was swapped with R10)*****~~

~~**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]~~

R-11. –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~~projected to be shed by the UFLS relays at each UFLS stage. The actual net Load shall be coincident with the entity's integrated hourly peak net Load during the previous year, as determined by measuring actual metered Load through the switches that would ~~be opened~~disconnect load if triggered by the UFLS relays. If there is no local metering of the load through said switches, the load may be calculated from measurements made at the nearest available metering. –(e.g., upstream metering on the distribution feeder that supplies the load to be shed). *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

M12~~1~~1. –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~~to demonstrate~~s~~ that it meets Requirement R12~~1~~1.

Formatted: Indent: Left: 0.25", Hanging: 0.4"

Formatted: Font color: Text 1

Formatted: Font color: Text 1

Formatted: Font color: Text 1

Formatted: Font color: Text 1

Formatted: Font color: Text 1

Formatted: Font: Italic, Font color: Text 1

Commented [RS11]: National Grid: Suggest to shorten. A technical writer may be able to help with this and eliminate words as "on the other hand."

Formatted: Font: Italic, Font color: Text 1

Formatted: Measure, Indent: Left: 0", Hanging: 0.31", Tab stops: 0.38", List tab

~~**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]~~

~~RATIONALE BOX:~~

~~It is recognized that, ideally, the amount of load to be shed in each stage of the UFLS program for every entity should perfectly match that prescribed in this Standard universally, for all phases of the load cycle, i.e., seasonal (summer vs. winter), weekly (weekday vs. weekend vs. holidays), daily (morning, noon, and night), etc. for all of the identified islands. Practically, however, this is obviously not possible because the load cycles of the various areas and sub-areas within any given island do not perfectly track the load cycle of the overall island. The UFLS program, on the other hand, is designed based on peak conditions for the overall island. The percentages of actual load shedding that would occur for any conditions other than peak, therefore, can only approximate that prescribed in the Standard. This being said, entities are required by R12 to document measured loads in the UFLS program coincident with their own annual peak, whether or not that peak occurs at the same time or in the same season as the peak of the identified island in which their load resides. Using individual entity peaks vs. overall island peaks provides a consistent approach for accounting purposes among the very entities that are responsible for designing and maintaining their UFLS programs.~~

R1~~2~~2. ~~3~~ ~~—~~Each Generator Owner shall set each generator underfrequency trip relay, if so equipped, on or below the appropriate generator underfrequency trip protection settings threshold curve in ~~Figure 1~~Figure 2, except as otherwise exempted in Requirements R1~~6~~5 and R1~~9~~8. ~~–~~*[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

M12. Each Generator Owner shall provide evidence such as reports, data sheets, spreadsheets or other documentation that demonstrates that it meets Requirement R12.

R1~~3~~3. ~~4~~ ~~—————~~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]*

M13. Each Generator Owner shall provide evidence such as emails, letters or other dated documentation that demonstrates that it meets Requirement R13.

Formatted: Measure, Tab stops: 0.31", Left + 0.38", List tab

Formatted: Measure, Indent: Left: 0", Hanging: 0.31", Tab stops: 0.38", List tab

Formatted: Indent: Left: -0.4", Hanging: 0.65"

Formatted: Indent: Left: -0.65", Hanging: 0.65"

Formatted: Default, Indent: Hanging: 0.65"

Formatted: Font: Italic

Formatted: Font: Bold

Formatted: Font: Bold

Formatted: Font: Italic

Formatted: Indent: Left: 0", First line: 0"

R1~~4~~. ~~5~~ 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]*

1~~4~~.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~~Figure 2.

1~~4~~.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~~Figure 2.

M14. Each Generator Owner shall provide evidence such as reports, data sheets, specifications, memorandum or other documentation that demonstrates that it meets Requirement R14.

R1~~5~~. ~~6~~ Each Generator Owner of existing non-nuclear units in service prior to the effective date of this standard, as documented in accordance with Attachments A or B, that have underfrequency protections set to trip above the appropriate curve in ~~Figure 1~~Figure 2 shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

1~~5~~.1. Set the underfrequency protection to operate at the lowest frequency allowed by the plant design and licensing limitations.

1~~5~~.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.

1~~5~~.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 that is within the UFLS island identified by the Planning Coordinator in Requirement R2.~~.~~

M1~~6~~5. 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 R1~~6~~5.

Formatted: Indent: Left: 0", First line: 0"

Formatted: Font: Italic

Formatted: Font: Bold

Formatted: Indent: Left: 0.5"

Formatted: Font: Bold

Formatted: Font: Bold

Formatted: Font: Bold

Formatted: Font: Italic

Formatted: Font: Bold

Formatted: Indent: Left: 0.13"

Formatted: Indent: Left: 0.5"

Formatted: Font: Bold

Formatted: Indent: Left: 0.5"

Formatted: Font: Bold

Formatted: Indent: Left: 0.5"

Commented [RS12]: From National Grid: Guy to tightening up standard so that existing units that do meet curve, cant file to not meet curve.

Commented [DML13]: Guy to tightening up standard so that existing units that do meet curve, cant file to not meet curve. Add dates to attachment A and B and remove from R15.

Formatted: Indent: Left: 0.5", Hanging: 0.4"

R1~~7~~6. 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 R1~~6~~5.3 for generating units in its respective NPCC area. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

M1~~7~~6. 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 R1~~7~~6.

R17. ~~8~~ 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 R1~~5~~6.3 for generating units in its respective NPCC area. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

M1~~8~~7. 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 R1~~8~~7.

R18. ~~9~~ 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~~Figure 2, based on their licensing design basis, shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

1~~8~~9.1. 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 57.8 Hz.

1~~9~~8.2. Set the frequency trip setting upper tolerance to no greater than + 0.1 Hz.

1~~8~~9.3. Transmit the initial frequency trip setting and any changes to the setting and the technical basis for the settings to the Planning Coordinator.

M1~~9~~8. 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~~Figure 2 shall provide evidence such as letters, reports and dated documentation that demonstrates that it meets Requirement R1~~8~~9.

Commented [RS14]: Update Attachment A per the comments submitted by Vincent M. Replace his with its.

Commented [DML15]: Vincent to modify attachment A

Formatted: Font: Italic

Formatted: Indent: Left: 0", Hanging: 0.31", Tab stops: 2.25", Left + Not at -2.5"

Formatted: Font: Italic

Commented [DML16]: Leave as is.

Formatted: Font: Italic

Formatted: Indent: Left: -0.06"

Formatted: Indent: Left: 0", Hanging: 0.25"

Formatted: Font: Italic

Formatted: Font: Bold

Formatted: Indent: Left: 0.5"

Formatted: Font: Bold

Formatted: Font: Bold

Commented [DML17]: Leave as is

R. 20 M19.20 Each Planning Coordinator shall provide evidence such as spreadsheets, system studies, or other documentation that demonstrates that it meets the requirements of Requirement R2019.

. TThe Planning Coordinator shall update its UFLS program database parameters 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.

M20. Each Planning Coordinator shall provide evidence such as spreadsheets, system studies, or other documentation that demonstrates that it meets the additional UFLS program database parameters of Requirement R20.

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

Formatted: Font: Bold

Formatted: Font: Bold

Formatted: Font: Bold

Formatted: Font: Bold

Formatted: Font: Bold

Formatted: Font: Bold

Formatted: Font: Bold

Formatted: Normal, Indent: Left: 0", First line: 0"

~~NERC PRC Standard on UFLS.[Violation Risk Factor: High] [Time Horizon: Long Term Planning]~~

Commented [RS18]: This requirement is covered by PRC-006-2 Automatic UFLS Continent Wide Standard Requirement 15.

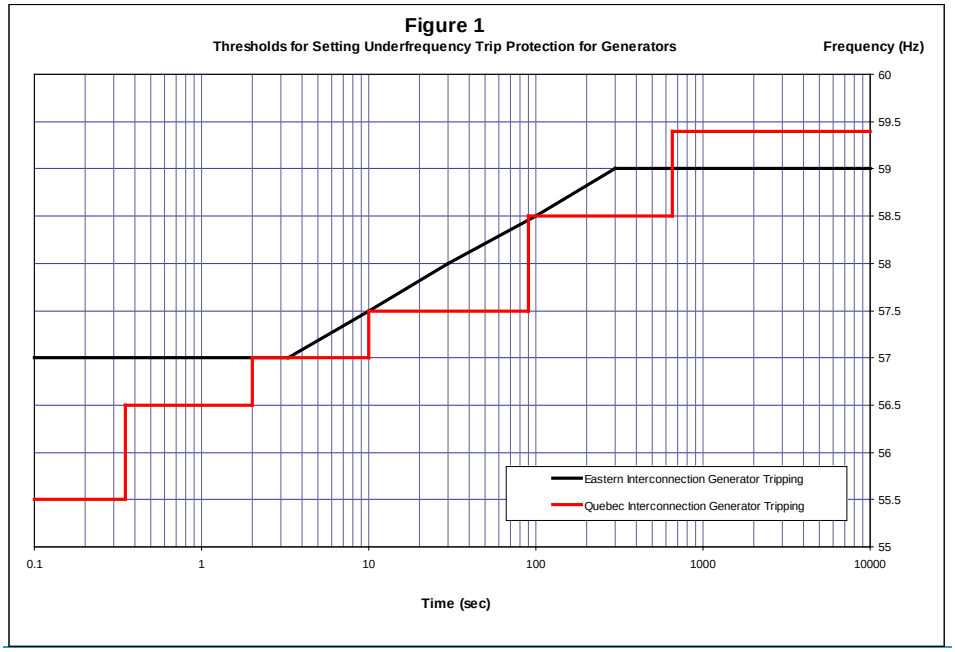
~~**R22** Each Distribution Provider, Transmission Owner and Generator Owner shall implement the load distribution changes based on the notification provided by the Planning Coordinator in accordance with Requirement R21. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]~~

Formatted: Indent: Left: 0", Hanging: 0.31"

~~**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]~~

Formatted: Indent: Left: 0", Hanging: 0.31"

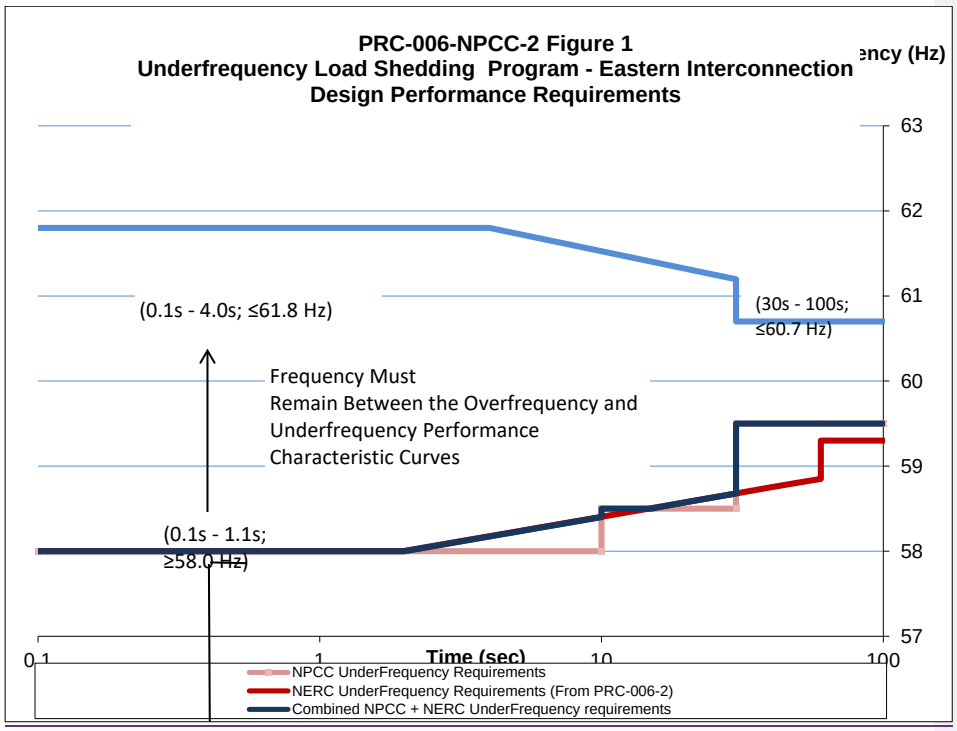
Figure 1

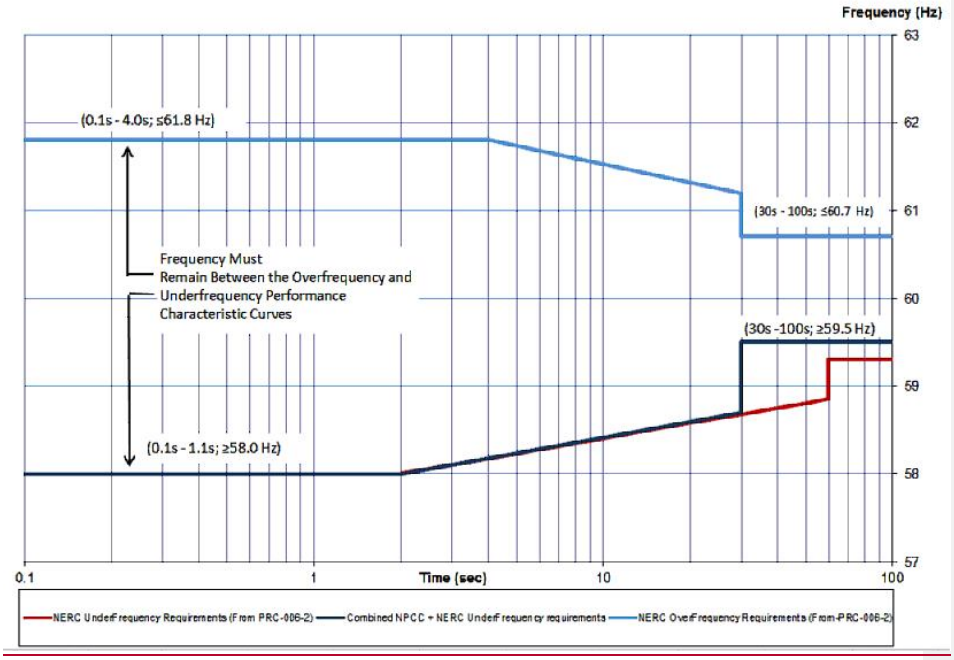

Thresholds for Setting Underfrequency Trip Protection for Generators
Frequency (Hz)
60
59.5
59
58.5
58
57.5
57
56.5
56
55.5
55
0.1
1
10
100
1000
10000
Time (sec)
Eastern Interconnection Generator Tripping
Quebec Interconnection Generator Tripping

~~Attachment 1~~Figure 1
PRC-006-NPCC-2
Underfrequency Load Shedding Program – Eastern Interconnection Frequency Hz Design Performance Requirements

Formatted: Centered, Don't add space between paragraphs of the same style

Formatted: Font: Bold


PRC-006-NPCC-2 Figure 1
Underfrequency Load Shedding Program - Eastern Interconnection
Design Performance Requirements
ency (Hz)
63
62
61
60
59
58
57
(0.1s - 4.0s; ≤61.8 Hz)
(30s - 100s; ≤60.7 Hz)
Frequency Must Remain Between the Overfrequency and Underfrequency Performance Characteristic Curves
(0.1s - 1.1s; ≥58.0 Hz)
0.1
1
10
100
Time (sec)
NPCC UnderFrequency Requirements
NERC UnderFrequency Requirements (From PRC-006-2)
Combined NPCC + NERC UnderFrequency requirements



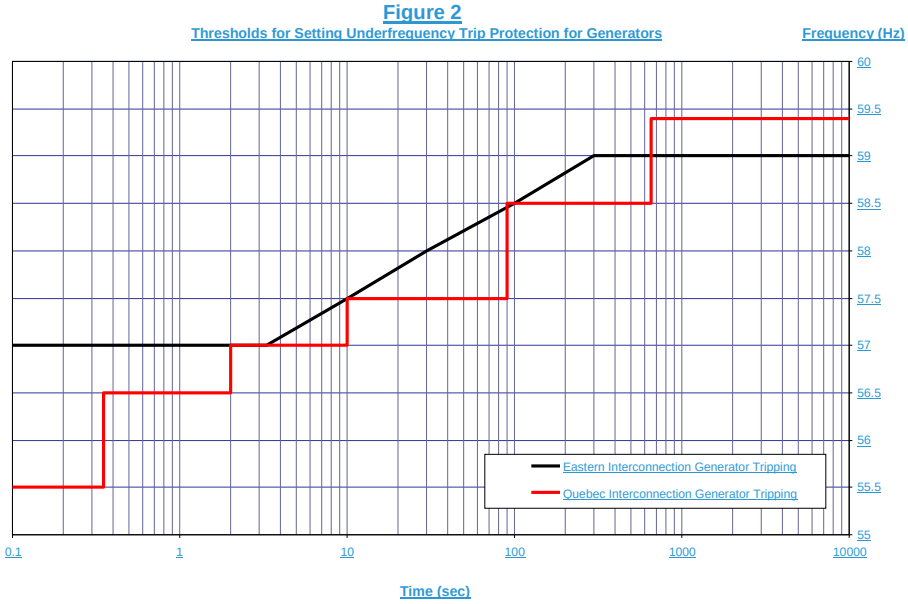
Formatted: List Number

Formatted: List Number

Figure 2
PRC-006-NPCC-2
Underfrequency Load Shedding Program – Thresholds for Setting Underfrequency Trip Protection for Generators

Figure 2

Thresholds for Setting Underfrequency Trip Protection for Generators



~~C.~~ Measures

Formatted: Indent: First line: 0"

Formatted: Indent: Left: 0.25", First line: 0"

~~**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.

Formatted: Normal, Don't adjust space between Latin and Asian text, Don't adjust space between Asian text and numbers

Formatted: Indent: Left: 0.25", Hanging: 0.4"

Formatted: Indent: Left: 0.25", Hanging: 0.4"

~~**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.~~

Formatted: Indent: Left: 0", First line: 0"

~~D.~~C. 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.

PRC-006-NPCC-~~1~~2 Attachment A

Compensatory Load Shedding Criteria for Ontario, Quebec, and the Maritime Provinces:

The Planning Coordinator in Ontario, Quebec and the Maritime provinces is responsible for establishing the compensatory load shedding requirements for all existing non-nuclear units in its NPCC area with underfrequency protections set to trip above the appropriate curve in ~~Figure 1~~Figure 2. In addition, it is the Planning Coordinator's responsibility to communicate these requirements to the appropriate Distribution Provider or Transmission Owner and to ensure that adequate compensatory load shedding is ~~-~~provided in all UFLS islands ~~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 as part of its UFLS Assessment based on the NERC PRC Standard on UFLS:

1. The Planning Coordinator shall identify, compile and maintain ~~an updated~~ a list of all existing non-nuclear generating units, in their Planning Coordinator area, in service prior to the effective date of ~~the~~Version 1 of the regional Standard (April, 2017 PRC-006-NPCC-1). The list must indicate generating units, if any, ~~effective date of this standard~~ that have their underfrequency protections set to trip above the appropriate curve in ~~Figure 1~~Figure 2. Generating Units not appearing on the list as of the effective date of Version 1 of the regional standard, as shown above, must have their Underfrequency protections set to trip on or below the appropriate curve in ~~Figure 1~~Figure 2. The list shall include the following information for each unit:

    1.1 Generator name and generating capacity
    1.2 Underfrequency protection trip settings, including frequency trip set points and time delays
    1.3 Physical and electrical location of the unit
    1.4 All islands within which the unit may operate~~, 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 In Ontario and in the Maritime provinces, ~~T~~the compensatory load shedding that is provided by the Distribution Provider or Transmission Owner shall be in addition to the amount that the Distribution Provider or Transmission Owner is required to shed as specified in Requirement R4~~.~~.

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~~Figure 2 during an underfrequency event. If the highest frequency at which the subject generator will trip above the appropriate curve in ~~Figure 1~~Figure 2 does not correspond to a specific UFLS program stage threshold setting, the compensatory load shedding shall be provided at the UFLS program stage with a frequency threshold setting that is higher than the highest frequency at which the subject generator will trip above the appropriate curve in ~~Figure 1~~Figure 2.

2.4 The amount of compensatory load shedding shall be equivalent (±5%) to the average net generator megawatt output for the prior two calendar years, as specified by the Planning Coordinator, plus expected station loads to be transferred to the system upon loss of the facility. The net generation output should only include those hours when the unit was a net generator to the electric system.

In the specific instance of a generating unit that has been interconnected to the electric system for less than two calendar years, the amount of compensatory load shedding shall be equivalent (±5%) to the maximum claimed seasonal capability of the generator over two calendar years, plus expected station loads to be transferred to the system upon loss of the facility.

PRC-006-NPCC-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~~Figure 2 of this standard. The Generator Owner shall follow the methodology below to determine compensatory load shedding requirements:

1. The Generator Owner shall identify~~, and~~ compile, and maintain a list of all of its existing non-nuclear generating units in service prior to the effective date of Version 1 of the regional ~~is s~~Standard (April, 2017 PRC-006-NPCC-1). The list must indicate the Generator Owner's generating units, if any, that ~~has~~ have their underfrequency protections set to trip above the appropriate curve in ~~Figure 1~~Figure 2. Generating Units not appearing on the list as of the effective date of Version 1 of the regional standard, as shown above, must have their Underfrequency protections set to trip on or below the appropriate curve in ~~Figure 1~~Figure 2. The list shall include the following information associated with each unit:

    1.1 Generator name and generating capacity
    1.2 Underfrequency protection trip settings, including frequency trip set points and time delays
    1.3 Physical and electrical location of the unit
    1.4 Smallest island within which the unit may operate as identified by the Planning Coordinator in Requirement R1 of this Standard.

2. For each generating unit identified in (1) above, the Generator Owner shall establish the requirements for compensatory load shedding based on criteria outlined below:

    2.1 In cases where a Distribution Provider or Transmission Owner has coordinated protection settings with the Generator Owner to cause the generator to trip above the appropriate curve in ~~Figure 1~~Figure 2, 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~~Figure 2, the Generator Owner shall arrange for a Distribution Provider or Transmission Owner to provide the appropriate amount of compensatory load to be shed within the 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[2] 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 ~~2~~ – 3	~~29.5~~ 29.5 – 31.5

UFLS Table 2: Eastern Interconnection

Distribution Providers and Transmission Owners with 50 MW[2] or more and less than 100 MW[2] of peak ~~-~~net Load shall implement a UFLS program with the following attributes:

UFLS Stage	Frequency Threshold (Hz)	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. ~~1.~~ The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communication times, and the rated breaker interrupting time. The underfrequency relay operating time is measured from the time when frequency passes through the frequency threshold setpoint, using a test rate of frequency decay of 0.2 Hz per second. If the relay operating time is dependent on the rate of frequency decay, the underfrequency relay operating time and any subsequent testing of the UFLS relays shall utilize a test rate of linear frequency decay of 0.2 Hz per second.
2. Peak net load shall be calculated as an average of the peak net load from the previous 3 years, excluding the current year.

Formatted: Numbered + Level: 1 + Numbering Style: 1, 2, 3, … + Start at: 2 + Alignment: Left + Aligned at: 0.25" + Indent at: 0.5"

Formatted: Left, Indent: Left: 0.25", Hanging: 0.4", No bullets or numbering

Formatted: Numbered + Level: 1 + Numbering Style: 1, 2, 3, … + Start at: 1 + Alignment: Left + Aligned at: 0.19" + Indent at: 0.44"

UFLS Table 3: Eastern Interconnection Distribution Providers and Transmission Owners with 25 MW[2] or more and less than 50 MW[2] of peak net Load shall implement a UFLS program with the following attributes:				
UFLS Stage	Frequency Threshold (Hz)	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. ~~1.~~ The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communication times, and the rated breaker interrupting time. The underfrequency relay operating time is measured from the time when frequency passes through the frequency threshold setpoint, using a test rate of frequency decay of 0.2 Hz per second. If the relay operating time is dependent on the rate of frequency decay, the underfrequency relay operating time and any subsequent testing of the UFLS relays shall utilize a test rate of linear frequency decay of 0.2 Hz per second.
2. Peak net load shall be calculated as an average of the peak net load from the previous 3 years, excluding the current year.

Formatted: Numbered + Level: 1 + Numbering Style: 1, 2, 3, … + Start at: 1 + Alignment: Left + Aligned at: 0.19" + Indent at: 0.44"

Formatted: Indent: Left: 0", First line: 0"

~~UFLS Table 4: Quebec Interconnection~~

Commented [DML19]: Quebec want this out of standard

	~~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.~~

Guidelines and Technical Basis:

~~Guidelines and Technical Basis~~

Standard PRC-006-2, R4 requires the Planning Coordinator to conduct a UFLS assessment at least once every five years. However, aside from a UFLS islanding event, it does not prescribe other factors or events which could warrant a new UFLS assessment in less than the five years time-frame.

PRC-006-NPCC-01 contained requirements if changes to load distribution impacted UFLS program performance (R21) but did not consider many other factors. The drafting team recommends retiring these requirements (R21, R22, R23) and replacing them with the following guidance.

Significant variations in the following factors could require a Planning Coordinator to conduct a new assessment:

- Changes to the BES that could modify the creation of islands or the severity of events such as new transmission topologies, revised protection schemes or new or revised RAS.
- Unforeseen islanding event
- Real and reactive load distribution (including changes to location of compensatory load shedding)
- Transmission Owner or Distribution Provider's inability to implement the UFLS program within the stated tolerances
- Load characteristics in particular frequency responsive load
- Automatic load restoration
- Generation geographical distribution
- Generator trip settings
- Generation mix in particular non-BES generation that may not be subject to frequency ride-through criteria

Generator dynamic modeling (MOD-027-1 - Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions) or system modeling (if variations in system response are detected under MOD-033 - Steady-State and Dynamic System Model Validation)

Formatted: Font: (Default) Times New Roman

Formatted: Left

Formatted: Font: (Default) Times New Roman

Commented [RS20]: Did not find the relevant Standard

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

Implementation Plan

Regional Reliability Standard PRC-006-NPCC-2 – Automatic Underfrequency Load Shedding

Applicable Standard(s)

- PRC-006-NPCC-2 – Automatic Underfrequency Load Shedding

Requested Retirement(s)

- PRC-006-NPCC-1 – Automatic Underfrequency Load Shedding

Applicable Entities

- Generator Owner
- Planning Coordinator
- Distribution Provider that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program.
- Transmission Owners that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program.

Background

The revisions to the PRC-006-NPCC-1 Automatic Underfrequency Load Shedding have been developed to address the following concerns.

1. 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.
2. 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 and potential retirement of Directory 12 Automatic Underfrequency Load Shedding Program.
3. 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.
4. 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.

Effective Date

The first day of the first calendar quarter 6 months following applicable governmental and regulatory approvals.

Retirement Date

Regional Reliability Standard PRC-006-NPCC-1 shall be retired immediately prior to the effective date of PRC-006-NPCC-2.

NPCC, Inc.

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

September 1, 2017

Subject: Posting for Open Process Review of *PRC-006-NPCC-2 Automatic Underfrequency Load Shedding.*

The clean and redlined versions of the revised NPCC Regional Standard PRC-006-NPCC-2 *Automatic Underfrequency Load Shedding*, have been posted on the NPCC Website for a 45-day comment period through October 16, 2017, along with a proposed Implementation Plan.

This initial draft has been developed in accordance with the NPCC Regional Standard Process Manual (RSPM) and within the scope of NPCC Regional Standard Authorization Request, which was accepted by the NPCC Regional Standard Committee (RSC). The revisions are also presented as mandated by the NERC Rules of Procedure. This initial draft does not include the Violation Severity Levels, which will be developed for the next posting period.

Among the proposed changes included in the initial draft version of the Standard are:

- Modifications to Figures #1 and #2 in the Standard
- Added a Guidelines and Technical Basis section (NERC may request us to create a separate document for this section and post it with the standard subsequent to approvals)
- Incorporated certain Criteria attributes from Directory #12 Automatic UFLS Program Requirements which will facilitate the retirement of Directory #12
- Additional clarification of requirement language
- Proposed retirements of some of the Requirements that are redundant to the PRC-006-2 Continent-wide NERC standard

Also posted is a set of questions developed by the Regional Standard Drafting Team to solicit comments on the draft standard and associated draft Implementation Plan for the Regional Standard. Included in these questions is one on cost effectiveness of the requirements.

Comments on the posted materials may be submitted through the NPCC Open Process Portal, which may be accessed through:
https://www.npcc.org/Standards/SitePages/DevStandardDetail.aspx?DevDocumentId=122
Subsequent to consideration of comments and revision, the standard is tentatively scheduled to be posted for a second comment period in the first quarter of 2018 and then for a 30-day pre-ballot review and 10-day ballot period following the conclusion of the review period.

Please contact me with any questions regarding this Standard.

Thank you.

Ruida Shu
Northeast Power Coordinating Council, Inc.
Senior Engineer, Reliability Standards and Criteria
Main: 212-840-1070
Direct: 917-934-7976
Fax: 212-302-2782
Email: rshu@npcc.org

A-10 BPS Classification CP-11 Working Group Update

Gerry Dunbar

October 11-12, 2017

CP-11 Action Plan --- Phase#1 2017

- Review Existing Methodology
  - Isolate Problems
  - Develop Improvements
- Develop New Methodologies
- Present Recommendation to the RCC

CP-11 Action Plan --- Phase#2 2018

- Test Proposed Methodology
- Consider Applicability to Directories
- Revise A-10 Document

Existing and Alternative Methodologies

- Goals:
  - Identify Critical Facilities
  - Simplify Methodology (less resource intensive)
  - Greater Regional Consistency:
    - Application
    - Outcome

Improvements to Existing Methodology

- Definitions
  - Local Area
  - SAI
- Base Case Set-up
  - Eight sub items.
- Sensitivity of A-10 to Protection System Changes
- Simulation Procedures and Assumptions

Research New Methodologies

- Proposal A:
  - Bright Line
  - Topology Based
- Proposal B:
  - Bright Line
  - Performance Test
- Proposal C
  - Bright Line
  - Performance Test

Next Steps

- October 2017:
  - Submit Final Report to TFCP
- November 2017:
  - NPCC Task Force Comments
- December 2017:
  - Present Proposed Methodology(s) to RCC
  - Obtain RCC Endorsement of Proposed Methodology for Phase 2 Testing

REGIONAL STANDARDS COMMITTEE

Chairman:

Guy V. Zito
Assistant Vice President - Standards
Northeast Power Coordinating Council, Inc.
Tel. (212) 840-1070
Email: gzito@npcc.org

Co-Vice Chairman:

Quintin Lee
Program Manager - Reliability Compliance
Eversource Energy
780 North Commercial Street
Manchester, NH 03101
Office: (603) 634-3579
Cell: (603) 315-9010
Email: quintin.lee@eversource.com

Co-Vice Chairman:

Michael Jones
Lead Analyst – FERC Compliance
40 Sylvan Road
Waltham, Massachusetts 02451
Tel. (781) 907-2404
Email: michael.jones@nationalgrid.com

Sector 1 - Transmission Owners

Hydro One Networks, Inc.

Primary
Paul Malozewski, P. Eng., MBA, PMP
Manager – Reliability Standards and Strategies
Tel. 416-345-5005
Email: paul.malozewski@hydroone.com

Alternate
Payam Farahbakhsh, M. Eng, P. Eng.
Network Management Engineer – Reliability Standards and Strategies
Tel. (416) 345-5484
Email: Payam.Farahbakhsh@HydroOne.com

Consolidated Edison Company of New York, Inc.

Primary
Michael Forte
Chief Transmission Planning Engineer
Tel. (212) 460-3416
Fax (212) 529-1130
Email: fortem@coned.com

Alternate
Martin Paszek
Manager, Bulk Power System Performance and Analysis
Tel. (212) 460-6415
Fax (212) 529-1130
Email: paszekm@coned.com

National Grid

Primary
Michael Schiavone
Director, Transmission Control Center – NY
7437 Henry Clay Blvd HCB-3
Liverpool, NY 13088
National Grid, US
Tel. (315) 460-4472
Email: Michael.schiavone@nationalgrid.com

Alternate

New Brunswick Power Corporation

Primary
Laura Mcleod, P.Eng.
Corporate Compliance
515 King St, Fredericton NB, Canada E3B 5G4
Tel. (506) 458-6662
Email: laura.mcleod@nbpower.com

Alternate

The United Illuminating Company

Primary

Alternate
Michele Tondalo
Compliance Analyst
180 Marsh Hill Road
Orange, Connecticut 06477
Tel. (203) 499-2542
Email: Michele.Tondalo@uinet.com

Hydro-Quebec TransÉnergie

Primary
Sylvain Clermont
Director, Reliability Standards and Regulatory Compliance
2 Complexe Desjardins, 19th floor, East Tower
Montréal, Québec, Canada H5B 1H7
Tel. (514) 879-4648
Email: clermont.sylvain@hydro.qc.ca

Alternate
Nicolas Turcotte
Manager Operating Procedures and Reliability Standards
2 Complexe Desjardins, 19th floor, East Tower
Montréal, Québec, Canada H5B 1H7
Tel. (514) 798-1223
Ext :8795182
Email: turcotte.nicolas@hydro.qc.ca

Orange & Rockland Utilities, Inc.

Primary
Ori Shmul
Principle Engineer – NERC Compliance
1 Blue Hill Plaza – Rm 405
Pearl River NY 10965
Tel. (845) 577-2510
Email: shmulm@oru.com

Alternate
Boris Shulim
Section Manager – Substation & Transmission Engineering
Orange and Rockland Utilities Inc.
390 West Route 59
Spring Valley NY 10977
845-577-3716
Email: shulimb@oru.com

Eversource Energy

Primary
Quintin Lee
Program Manager - Reliability Compliance
Eversource Energy
780 North Commercial Street
Manchester, NH 03101
Office: (603) 634-3579
Cell: (603) 315-9010
Email: quintin.lee@eversource.com

Alternate
Mark J. Kenny
Manager - Reliability Compliance
Eversource Energy
Westwood, MA 02090
Tel. (781) 441-8179
Cell. (617) 429-1837
Email: Mark.Kenny@eversource.com

Sector (2) - Reliability Coordinators

New York Independent System Operator

Primary
Gregory A. Campoli
Manager, Reliability Compliance & Industry Affairs
Tel. (518) 356-6159
Email: gcampoli@nyiso.com

Alternate
James (Jim) Grant
Reliability Senior Engineer
Tel. (518) 356-6128
Email: jgrant@nyiso.com

ISO New England, Inc.

Primary
Kathleen M. Goodman
Senior Operations Compliance Coordinator
Tel. (413) 535-4111
Email: kgoodman@iso-ne.com

Alternate
Josh Eason
Associate Compliance Analyst
Tel. (413) 540-4495
Email: jeason@iso-ne.com

Independent Electricity System Operator

Primary
Helen Lainis
Senior Engineer/Technical Officer
Tel. (905) 855-4106
Email: helen.lainis@ieso.ca

Alternate
Scott Berry
Senior Engineer/Technical Officer
Tel. (905) 403-6912
Email: scott.berry@ieso.ca

Hydro-Quebec TransÉnergie

Primary
Chantal Mazza
DP Contrôle des mouvements d'énergie et exploitation du réseau
2 Complexe Desjardins, 19th floor, East Tower
Montréal, Québec, Canada H5B 1H7
Tel. (514) 798-1223 Ext. 8795499
Email: mazza.chantal@hydro.qc.ca

Alternate
Michael Godbout
Engineer – Reliability Standards & Operating Procedures Reliability Coordinator
2 Complexe Desjardins, 13th floor, East Tower
Montreal, Québec, Canada H5B 1H7
Tel. (514) 798-1223 Ext. 8795852
Email: Godbout.Michael@hydro.qc.ca

New Brunswick Power Corporation

Primary
Randy MacDonald
Director, Corporate Compliance
Tel. (506) 458-4653
Cell. (506) 470-3536
Email: RaMacDonald@NBPower.com

Alternate
Tim Hicks
Document & Compliance Coordinator
Tel. (506) 458-6511
Cell. (506) 238-3851
Email: Tim.Hicks@nbpower.com

Sector (3) - Transmission Dependent Utilities ("TDUs"); Distribution Companies and Load-Serving Entities ("LSEs")

Consolidated Edison Company of New York, Inc.

Primary
Daniel J. Grinkevich
Sr. Engineer, NERC Reliability Compliance
4 Irving Place, Room 1300 NW
New York, NY 10003
Tel. (212) 460-3991
Fax (845) 577-3256
Email: grinkevichd@coned.com

Alternate
Dermot Smyth
Senior Enigneer
Tel. (212) 460-4093
Fax (212) 529-1130
Email: smythd@coned.com

National Grid

Primary
Michael Jones
Lead Analyst – FERC Compliance
40 Sylvan Road
Waltham, Massachusetts 02451
Tel. (781) 907-2404
Email: michael.jones@nationalgrid.com

Alternate

Orange & Rockland Utilities, Inc.

Primary	Alternate
David Burke	Ben Wu
Senior Specialist - Compliance	Principal Engineer
Tel. (845) 577-2841	Transmission & Substation Engineering
Fax (845) 577-2840	Tel. (845) 577-3713
Email: burkeda@oru.com	Email: WUB@oru.com

Sector (4) - Generator Owners

Consolidated Edison Company of New York, Inc.

Primary	Alternate
Peter Yost	Robert Winston
Manager, Standards & Compliance	Sr. Engineer
Tel. (212) 460-2889	Tel. (212) 460-2790
Fax (212) 529-1130	Fax (212) 529-1130
Email: yostp@coned.com	Email: winstonr@coned.com

New York Power Authority

Primary	Alternate
Salvatore Spagnolo	Saul Rojas
Program Manager, Reliability Standards & Compliance	VP – Technical Compliance
Tel. (914) 390-8224	Tel. (914) 681-6661
Mob. (347) 992-7015	Mob. (914) 960-0162
Email: Salvatore.Spagnolo@nypa.gov	Email: Saul.Rojas@nypa.gov

Dominion Energy Services, Inc.

Primary	Alternate
Sean Bodkin	Connie Lowe
NERC Compliance Policy Manager	Regulatory and Market Policy Manager
Dominion Energy Services, Inc.	Dominion Energy Services, Inc.
Tel. (804) 771-8429, tie line 8-786-8429	Tel. (804) 771-4447, tie 8-736-4447
Cell: (804) 292-5721	Cell: 804-239-3201
Email: Sean.Bodkin@dominionenergy.com	Email: connie.lowe@dominionenergy.com

Ontario Power Generation, Inc.

Primary
David Ramkalawan, P.Eng.
Director – Reliability Compliance
Tel. (416) 592-6089
Email: david.ramkalawan@opg.com

Alternate
Constantin Chitescu
Regulatory Analyst
Tel. (416) 592-6055
Email: constantin.chitescu@opg.com

NextEra Energy, LLC

Primary
Silvia Parada Mitchell
Director, Reliability Standards & Compliance
Tel. (561) 904-3767
Email: silvia.parada.mitchell@fpl.com

Alternate
Summer Esquerre
Manager, Reliability Standards & Compliance
Tel. (561) 904-3765
Email: summer.esquerre@fpl.com

Alternate
Rogelio Moraitis
Compliance Analyst
Reliability Standards and Compliance
Tel. (561) 904-3402
Email: Rogelio.Moraitis@nee.com

Entergy Services, Inc

Primary
Glen Smith
NERC Compliance
Entergy Services, Inc
440 Hamilton Avenue
White Plains, NY 10601
914-272-3513
Email: gsmith@entergy.com

Alternate

Sector (5) - Marketers, Brokers and Aggregators

Consolidated Edison Company of New York, Inc.

Primary
Brian O'Boyle
Engineer
Tel. (212) 460-5596
Fax (212) 529-1130
Email: oboyleb@coned.com

Alternate
Alyson Slanover
Engineer
Tel. (212) 460-8351
Fax (212) 529-1130
Email: slanovera@coned.com

Utility Services, Inc.

Primary
Brian Robinson
Compliance Analyst
Tel. (802) 241-1400
Email: brian.robinson@utilitysvcs.com

Alternate
Brian Evans-Mongeon
President/CEO
Tel. (802) 241-1400
Email: brian.evans-mongeon@utilitysvcs.com

Sector (6) – State and Provincial Regulatory and/or Governmental Authorities

New York Power Authority

Primary
Shivaz Chopra
Program Manager, Reliability Standards & Compliance
Tel. (914) 681-6828
Tel. (914) 391-6839
Email: shivaz.chopra@nypa.gov

Alternate
Erick Barrios
Engineer, Reliability Standards & Compliance
Tel. (914) 681-6781
Tel. (914) 506-2152
Email: Erick.Barrios@nypa.gov

New York State Department of Public Service

Primary
Vijay Puran
Utility Supervisor, Bulk Electric Systems
Tel. (518) 486-5948
Email: vijay.puran@dps.ny.gov

Alternate
Jerry Ancona
Senior Engineer
Tel. (315) 428-5160
Email: Jerry.Ancona@dps.ny.gov

Sector 7 – Sub-Regional Reliability Councils, Customers and Other Regional Entities and Interested Entities

New York State Reliability Council, LLC

Primary
Alan Adamson
Independent Consultant
2104 Braxton Street
Clermont, FL 34711
Tel. (352) 989-4653
Email: aadamson@nycap.rr.com

Alternate

Submission Description: (doc-less) Motion to Intervene of North American Electric Reliability Corporation under ER17-2387-000, et. al..

Submission Date: 9/21/2017 2:58:56 PM

Filed Date: 9/21/2017 2:58:56 PM

Dockets

ER17-2387-000 California Independent System Operator Corporation submits tariff filing per 35.13(a)(2)(iii): 2017-08-31 Transferred Frequency Response Agreement Bonneville Power Admin. submitted on 8/30/2017 5:15:09 PM, Filing Type code: 10
ER17-2393-000 California Independent System Operator Corporation submits tariff filing per 35.13(a)(2)(iii): 2017-08-31 Transferred Freqnuency Response Agreement Grant County submitted on 8/31/2017 1:29:21 PM, Filing Type code: 10
ER17-2398-000 California Independent System Operator Corporation submits tariff filing per 35.13(a)(2)(iii): 2017-08-31 Transferred Frequency Response Agreement Chelan County submitted on 8/31/2017 2:34:47 PM, Filing Type code: 10

Filing Party/Contacts:

Filing Party	Signer (Representative)	Other Contact (Principal)
North American Electric Reliability Corporation candice.castaneda@nerc.net		

Basis for Intervening:
The North American Electric Reliability Corporation (“NERC”) was formed to serve as the electric reliability organization (“ERO”) authorized by Section 215 of the Federal Power Act. NERC was certified as the ERO by the Federal Electricity Regulatory Commission’s (“Commission”) Order issued July 20, 2006, in Docket No. RR06-1-000. As the ERO, NERC is subject to audit by the Commission and governmental authorities in Canada.

In Docket Nos. ER17-2387, ER17-2393, and ER17-2398, the California Independent System Operator Corporation (“CAISO”) requested Commission approval for Transferred Frequency Response Agreements between CAISO and Bonneville Power Administration, Grant County Public Utility District, and Chelan County Public Utility District respectively, intended to support CAISO’s compliance with NERC Reliability Standard BAL-003-1.1.

NERC has a substantial interest in these proceedings. No other party can adequately represent NERC’s interest. Therefore, it is in the public interest to permit this intervention.

20170921-5121 FERC PDF (Unofficial) 9/21/2017 2:58:56 PM

Document Content(s)

803987_Interv.TXT.....1-1

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. _____**

JOINT PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION AND RELIABILITYFIRST CORPORATION FOR APPROVAL OF PROPOSED REGIONAL RELIABILITY STANDARD BAL-502-RF-03

Jason Blake
General Counsel
Megan Gambrel
Senior Counsel
ReliabilityFirst Corporation
3 Summit Park Drive, Suite 600
Cleveland, OH 44131
(216) 503-0600
jason.blake@rfirst.org
megan.gambrel@rfirst.org

Counsel for the ReliabilityFirst Corporation

Shamai Elstein
Senior Counsel
Marisa Hecht
Counsel
North American Electric Reliability Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 400-3000
shamai.elstein@nerc.net
marisa.hecht@nerc.net

Counsel for the North American Electric Reliability Corporation

September 7, 2017

TABLE OF CONTENTS

I. EXECUTIVE SUMMARY 2

II. NOTICES AND COMMUNICATIONS 4

III. BACKGROUND 4

A. Regulatory Framework 4

B. ReliabilityFirst Regional Reliability Standards Development Procedure 6

C. FERC Directives Addressed by BAL-502-RF-03 6

D. Development of Proposed Regional Reliability Standard 8

IV. JUSTIFICATION FOR APPROVAL 9

A. Justification for the Need for the Proposed Regional Reliability Standard 10

B. Description and Technical Basis of Proposed Revisions 11

C. Enforceability of Proposed Regional Reliability Standard BAL-502-RF-03 13

V. EFFECTIVE DATE 14

VI. CONCLUSION 14

Exhibit A Proposed Regional Reliability Standard, BAL-502-RF-03 – Planning Resource Adequacy Analysis, Assessment and Documentation

Exhibit B Implementation Plan for Proposed Regional Reliability Standard BAL-502-RF-03

Exhibit C Order No. 672 Criteria for Proposed Regional Reliability Standard BAL-502-RF-03

Exhibit D Summary of Development History and Complete Record of Development

Exhibit E Planning Resource Adequacy Analysis, Assessment and Documentation Standard Drafting Team Roster

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. _____**

JOINT PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION AND RELIABILITYFIRST CORPORATION FOR APPROVAL OF PROPOSED REGIONAL RELIABILITY STANDARD BAL-502-RF-03

Pursuant to Section 215(d)(1) of the Federal Power Act ("FPA")[1] and Section 39.5[2] of the Federal Energy Regulatory Commission's ("FERC" or "Commission") regulations, the North American Electric Reliability Corporation ("NERC")[3] and the ReliabilityFirst Corporation ("ReliabilityFirst") hereby submit proposed regional Reliability Standard BAL-502-RF-03 – Planning Resource Adequacy Analysis, Assessment and Documentation for Commission approval. Proposed regional Reliability Standard BAL-502-RF-03 establishes common criteria, based on "one day in ten year" loss of Load expectation principles, for the analysis, assessment, and documentation of Resource Adequacy for Load in the ReliabilityFirst region.[4]

NERC requests that the Commission approve proposed regional Reliability Standard BAL-502-RF-03 (**Exhibit A**) and find that the proposed regional Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest. NERC also requests approval of: (i) the Implementation Plan (**Exhibit B**) for the proposed regional Reliability Standard; (ii) the associated Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") (**Exhibit A**);

---

1 16 U.S.C. § 824o (2012).

2 18 C.F.R. § 39.5 (2017).

3 The Commission certified NERC as the electric reliability organization ("ERO") in accordance with Section 215 of the FPA on July 20, 2006. *N. Am. Elec. Reliability Corp.*, 116 FERC ¶ 61,062 (2006).

4 Unless otherwise designated, all capitalized terms shall have the meaning set forth in the *Glossary of Terms Used in NERC Reliability Standards*, http://www.nerc.com/files/Glossary_of_Terms.pdf.

and (iii) the retirement of regional Reliability Standard BAL-502-RFC-02. The NERC Board of Trustees adopted proposed regional Reliability Standard BAL-502-RF-03 on August 10, 2017.

As required by Section 39.5(a)[5] of the Commission's regulations, this petition presents the technical basis and purpose of proposed regional Reliability Standard BAL-502-RF-03; a demonstration that the proposed regional Reliability Standard meets the criteria identified by the Commission in Order No. 672[6] (**Exhibit C**); and a summary of the development history (**Exhibit D**).

I. EXECUTIVE SUMMARY

Proposed regional Reliability Standard BAL-502-RF-03 addresses directives from FERC to (1) add time horizons applicable to the requirements and (2) consider including a requirement that the Planning Coordinators identify any gap between the needed amount of planning reserves and the documented projected planning reserves determined from the Resource Adequacy analysis. The proposed revisions resulted from a periodic review of BAL-502-RFC-02.

The purpose of proposed regional Reliability Standard BAL-502-RF-03 is to establish common criteria, based on "one day in ten year" loss of Load expectation principles, for the analysis, assessment, and documentation of Resource Adequacy for Load in the ReliabilityFirst region. The requirements address the following: (1) annually performing and documenting a Resource Adequacy analysis; (2) annually documenting and posting projected Load and resource capability to demonstrate the sufficiency of planning reserves over a ten-year period for certain areas identified in the Resource Adequacy analysis; and (3) identifying any gaps between the

[5] 18 C.F.R. § 39.5(a).

[6] The Commission specified in Order No. 672 certain general factors it would consider when assessing whether a particular Reliability Standard is just and reasonable. *See* Order No. 672, *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, FERC Stats. & Regs. ¶ 31,204, at PP 262, 321-37, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006) ("Order No. 672").

needed planning reserves and the projected planning reserves documented in the Resource Adequacy analysis.

For the reasons discussed below, NERC and ReliabilityFirst respectfully request the Commission approve proposed regional Reliability Standard BAL-502-RF-03, the associated VRFs and VSLs, the associated Implementation Plan, and the retirement of the existing regional Reliability Standard BAL-502-RFC-02 as just, reasonable, not unduly discriminatory or preferential, and in the public interest. The following petition presents the justification for approval and supporting documentation.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:[7]

Jason Blake*
General Counsel
Megan Gambrel*
Senior Counsel
ReliabilityFirst Corporation
3 Summit Park Drive, Suite 600
Cleveland, OH 44131
(216) 503-0600
jason.blake@rfirst.org
megan.gambrel@rfirst.org

Counsel for the ReliabilityFirst Corporation

Shamai Elstein*
Senior Counsel
Marisa Hecht*
Counsel
North American Electric Reliability Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 400-3000
shamai.elstein@nerc.net
marisa.hecht@nerc.net

Counsel for the North American Electric Reliability Corporation

III. BACKGROUND

The following background information is provided below: (a) an explanation of the regulatory framework for NERC and regional Reliability Standards; (b) an explanation of the ReliabilityFirst regional Reliability Standards development process; (c) the FERC directives addressed by the revisions; and (d) the development of proposed regional Reliability Standard BAL-502-RF-03.

A. Regulatory Framework

By enacting the Energy Policy Act of 2005,[8] Congress entrusted the Commission with the duties of approving and enforcing rules to ensure the reliability of the Nation's Bulk-Power

[7] Persons to be included on the Commission's service list are identified by an asterisk. NERC respectfully requests a waiver of Rule 203 of the Commission's regulations, 18 C.F.R. § 385.203, to allow the inclusion of more than two persons on the service list in this proceeding.

[8] 16 U.S.C. § 824o (2012).

System, and with the duties of certifying an ERO that would be charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval. Section 215(b)(1)[9] of the FPA states that all users, owners, and operators of the Bulk-Power System in the United States will be subject to Commission-approved Reliability Standards. Section 215(d)(5)[10] of the FPA authorizes the Commission to order the ERO to submit a new or modified Reliability Standard. Section 39.5(a)[11] of the Commission's regulations requires the ERO to file with the Commission for its approval each Reliability Standard that the ERO proposes should become mandatory and enforceable in the United States, and each modification to a Reliability Standard that the ERO proposes should be made effective.

The Commission has the regulatory responsibility to approve Reliability Standards that protect the reliability of the Bulk-Power System and to ensure that such Reliability Standards are just, reasonable, not unduly discriminatory or preferential, and in the public interest. Pursuant to Section 215(d)(2) of the FPA[12] and Section 39.5(c)[13] of the Commission's regulations, the Commission will give due weight to the technical expertise of the ERO with respect to the content of a Reliability Standard.

Similarly, the Commission approves regional Reliability Standards proposed by Regional Entities if the regional Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest.[14] In addition, Order No. 672 sets forth additional criteria for regional Reliability Standards. A regional difference from a continent-wide Reliability

---

9 *Id.* § 824o(b)(1).

10 *Id.* § 824o(d)(5).

11 18 C.F.R. § 39.5(a).

12 16 U.S.C. § 824o(d)(2).

13 18 C.F.R. § 39.5(c)(1).

14 Section 215(d)(2) of the FPA and 18 C.F.R. § 39.5(a).

Standard must either be: (1) more stringent than the continent-wide Reliability Standard, or (2) necessitated by a physical difference in the Bulk-Power System.[15]

B. ReliabilityFirst Regional Reliability Standards Development Procedure

The proposed regional Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved ReliabilityFirst Reliability Standards Development Procedure.[16] In accepting NERC's delegation agreements with the Regional Entities, the Commission found that NERC's proposed common attributes for regional Reliability Standard development and ReliabilityFirst's Reliability Standards development process provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards.[17] ReliabilityFirst considers the comments of all stakeholders, and a vote of stakeholders and adoption by the ReliabilityFirst Board of Directors is required to approve a regional Reliability Standard. Once the regional Reliability Standard is approved by the ReliabilityFirst Board of Directors, NERC posts the approved regional Reliability Standard for an additional comment period. Then the NERC Board of Trustees must adopt the regional Reliability Standard before it is submitted to the Commission for approval.

C. FERC Directives Addressed by BAL-502-RF-03

In addition to approving regional Reliability Standard BAL-502-RFC-02 in Order No. 747, the Commission also directed ReliabilityFirst to: (1) add time horizons to the two main requirements, and (2) consider including a requirement that the Planning Coordinators identify any

---

[15] Order No. 672 at P 291.

[16] *Amendments to Delegation Agreement with ReliabilityFirst Corp.*, Letter Order, Docket No. RR12-12-000 (Oct. 24, 2012) (approving revised ReliabilityFirst Reliability Standards Development Procedure). The ReliabilityFirst Reliability Standards Development Procedure is available at https://rfirst.org/standards/Documents/Reliability%20Standards%20Developmental%20Procedure.pdf (effective Oct. 24, 2012).

[17] *Order Accepting ERO Compliance Filing, Accepting ERO/Regional Entity Delegation Agreements, and Accepting Regional Entity 2007 Business Plans*, 119 FERC ¶ 61,060, at P 17 (2007).

gap between the needed amount of planning reserves determined in Requirement R1, Part 1.1 and the planning reserves documented in Requirement R2 as determined from the Resource Adequacy analysis.[18] The Commission directed ReliabilityFirst to address these directives during its scheduled five-year review of BAL-502-RFC-02.

When BAL-502-RFC-02 was submitted to FERC, it did not include time horizons, which NERC noted in its petition to approve the regional Reliability Standard and the Commission mentioned in the Notice of Proposed Rulemaking.[19] NERC and the Regional Entities use time horizons as a factor in determining the size of a sanction. As noted in the Sanction Guidelines in Appendix 4B of the NERC Rules of Procedure, "Reliability Standards involving longer and broader time horizons, such as long-term planning activities, may have a lesser immediate impact and pose less immediate risk to the reliability of the Bulk Power System than Reliability Standards involving shorter and narrower timeframes, such as Registered Entities' conduct in real time. Similarly, Reliability Standards involving longer and broader time horizons typically will provide a longer time period over which to discover and remedy a violation when compared to Reliability Standards involving more immediate activities such as next-day planning, same-day operations or real-time operations."[20]

In the Notice of Proposed Rulemaking, the Commission stated that time horizons are important for NERC penalty determination but also acknowledged that time horizons were not

---

[18] Order No. 747, *Planning Resource Adequacy Assessment Reliability Standard*, 134 FERC ¶ 61,212, at PP 53, 65 (2011) ("Order No. 747").

[19] *NERC Petition for Approval of Proposed RFC Regional Reliability Standard BAL-502-RFC-02*, Docket No. RM10-10-000 (Dec. 14, 2009) ("Petition"); *Planning Resource Adequacy Assessment Reliability Standard*, Notice of Proposed Rulemaking, 133 FERC ¶ 61,066, at P 21 (2010).

[20] NERC, Rules of Procedure, Sanction Guidelines of the North American Electric Reliability Corporation, Appendix 4B, Section 2.7 (effective July 1, 2014), http://www.nerc.com/FilingsOrders/us/RuleOfProcedureDL/Appendix_4B_SanctionGuidelines_20140701.pdf.

critical in its determination to approve BAL-502-RFC-02.[21] ReliabilityFirst informed NERC that its standards development process did not include development of time horizons, but it was moving towards requiring the assignment of time horizons for its regional Reliability Standards.[22] Moreover, ReliabilityFirst noted that the requirements of the regional Reliability Standard are planning-oriented for one year and beyond.[23]

Additionally, in the Notice of Proposed Rulemaking, the Commission noted that BAL-502-RFC-02 did not include a requirement to document any gap between the planning reserve margin calculated pursuant to Requirement R1, Part 1.1 and the actual planning reserve documented in Requirement R2 as determined by the Resource Adequacy analysis.[24] The Commission further noted that it would be useful for Planning Coordinators to identify and document any deficiencies in planning reserves to help ensure that entities are aware of potential risks regarding the capability to balance resources and demand in a planning timeframe.[25] In its comments to the Notice of Proposed Rulemaking, ReliabilityFirst agreed this would be appropriate to consider during the five-year review.[26] As such, the Commission accepted this commitment in Order No. 747, noting that the requirement is for documentation and would not require entities to install additional generation or transmission capacity.[27]

D. Development of Proposed Regional Reliability Standard

As further described in Exhibit D hereto, proposed regional Reliability Standard BAL-502-RF-03 was developed by the Planning Resource Adequacy Analysis, Assessment and

---

21 NOPR, 133 FERC ¶ 61,066, at P 23.

22 Petition, Appendix C-8.

23 *Id.*

24 NOPR, 133 FERC ¶ 61,066, at P 32.

25 *Id.* at P 33.

26 Comments of ReliabilityFirst Corporation to Notice of Proposed Rulemaking Issued Oct. 21, 2010, *Planning Resource Adequacy Assessment Reliability Standard*, Docket No. RM10-10-000 at pg. 6.

27 Order No. 747 at PP 63, 65.

Documentation Standard Drafting Team in accordance with the ReliabilityFirst Reliability Standards Development Procedure. On February 1, 2017, BAL-502-RF-03 received the requisite approval from the registered ballot body in its initial ballot, with an affirmative majority of votes greater than two-thirds determined for each category. However, because ReliabilityFirst received at least one negative vote with comment during the initial ballot, ReliabilityFirst posted BAL-502-RF-03 for a 10-Day recirculation ballot beginning February 6, 2017. On February 15, 2017, BAL-502-RF-03 received the requisite number of affirmative votes to pass on recirculation ballot. The ReliabilityFirst Board of Directors approved BAL-502-RF-03 on June 1, 2017 and subsequently approved the regional Reliability Standard to be submitted to the NERC Board of Trustees for adoption. NERC posted the regional Reliability Standard for a 45-day comment period concluding on June 12, 2017. There were no additional changes after this comment period. The NERC Board of Trustees adopted BAL-502-RF-03 on August 10, 2017.

IV. JUSTIFICATION FOR APPROVAL

As discussed in detail in Exhibit C, proposed regional Reliability Standard BAL-502-RF-03 is just, reasonable, not unduly discriminatory or preferential, and in the public interest. As described more fully herein and in Exhibit C, the proposed regional Reliability Standard provides reliability benefits for the Bulk-Power System in the ReliabilityFirst region.

The purpose of proposed regional Reliability Standard BAL-502-RF-03 is to establish common criteria, based on "one day in ten year" loss of Load expectation principles, for the analysis, assessment, and documentation of Resource Adequacy for Load in the ReliabilityFirst region. The provisions of the proposed regional Reliability Standard provide requirements for Planning Coordinators in the ReliabilityFirst region regarding resource adequacy assessment, which is not currently addressed in NERC's continent-wide Reliability Standards. In approving BAL-502-RFC-02, the Commission stated that, "like other planning standards, BAL-502-RFC-02

provides for the reliable operation of the Bulk-Power System as it will help identify areas of concern that, if left unresolved, could result in future instability, uncontrolled separation, or cascading failures of the Bulk-Power System."[28] Proposed BAL-502-RF-03 provides this same benefit with additional proposed enhancements. Therefore, the proposed regional Reliability Standard meets a reliability need for the ReliabilityFirst region, and as discussed below, the proposed modifications provide additional support for the reliable operation of the Bulk-Power System.

The proposed regional Reliability Standard includes requirements for annually performing and documenting a Resource Adequacy analysis (Requirement R1), annually documenting the projected Load and resource capability for certain areas identified in the Resource Adequacy analysis (Requirement R2), and identifying any gaps between the needed amount of planning reserves determined pursuant to Requirement R1, Part 1.1 and the projected planning reserves documented pursuant to Requirement R2 (Requirement R3).

This section of the petition addresses: (i) the justification of the need for the proposed regional Reliability Standard; (ii) the description and technical basis of the proposed revisions; and (iii) the enforceability of the proposed regional Reliability Standard.

A. Justification for the Need for the Proposed Regional Reliability Standard

Proposed regional Reliability Standard BAL-502-RF-03 meets the criteria to justify the need for a regional Reliability Standard as it is more stringent than the related continent-wide NERC Reliability Standards, which do not presently address assessment of resource adequacy in the planning horizon covered in the proposed regional Reliability Standard. As noted above, the Commission previously recognized that the analysis required by this proposed regional Reliability

[28] Order No. 747 at P 25.

Standard may help identify issues that could cause future instability, uncontrolled separation, or cascading failures of the Bulk-Power System.[29] Therefore, the proposed regional Reliability Standard BAL-502-RF-03 is justified because it meets the criteria in Order No. 672 to be more stringent than continent-wide Reliability Standards. Entities that perform the functions to which the continent-wide standards and the proposed regional Reliability Standard apply need to comply with all applicable standards, so the proposed regional Reliability Standard provides a level of support to the ReliabilityFirst region in addition to the continent-wide standards.

B. Description and Technical Basis of Proposed Revisions

The proposed revisions add in time horizons to Requirements R1 and R2; add Requirement R3 to identify any gaps between the needed amount of planning reserves defined in Requirement R1, Part 1.1 and the projected planning reserves document in Requirement R2; and add other corresponding changes to the measures. In addition, the proposed revisions include minor clarifications and updates to conform to the current Reliability Standards template.

To address the time horizons directive, the standard drafting team selected "long-term planning" for the time horizons for Requirements R1, R2, and R3 of proposed BAL-502-RF-03. As noted above in Section III.C, ReliabilityFirst stated that the requirements address a planning horizon of one year or more. In the context of determining violations, NERC defines "long-term planning" as a planning horizon of one year or longer. Therefore, the "long-term planning" time horizon is most appropriate for the BAL-502-RF-03 requirements.[30]

---

[29] *Id.*

[30] NERC Reliability Standards requirements fall into one of five time horizon categories: (1) long-term planning – a planning horizon of one year or longer; (2) operations planning – operating and resource plans from day-ahead up to and including seasonal; (3) same-day operations – routine actions required within the timeframe of a day, but not real-time; (4) Real-time operations – actions required within one hour or less to preserve the reliability of the Bulk Electric System; and (5) operations assessment – follow-up evaluations and reporting of Real-time operations.

BAL-502-RF-03, Requirement R1 requires a Planning Coordinator to perform a Resource Adequacy analysis annually for the planning year. Requirement R2 requires a Planning Coordinator to annually document the projected Load and resource capability for certain areas identified in the Resource Adequacy analysis for each year through year ten. Finally, proposed Requirement R3 requires a Planning Coordinator to identify gaps in planning reserves identified in Requirement R1, Part 1.1 and documented in Requirement R2. As each of these requirements address a planning horizon of at least a year, the "long-term planning" time horizon is justified for the requirements in BAL-502-RF-03.

As noted in Section III.C above, ReliabilityFirst committed to considering a requirement to identify and document any gaps between the planning reserves identified under Requirement R1, Part 1.1 and the projected planning reserves documented under Requirement R2 during its five-year review of BAL-502-RFC-02. The standard drafting team reviewed the 2015 Long-term Reliability Assessment[31] and the 2014 Probabilistic Assessment[32] reports to determine if this gap analysis was addressed by non-standards activities. Although the reports both included identification of gaps, the standard drafting team noted that the reports were not required to include this analysis. Therefore, the standard drafting team concluded that a requirement to document these gaps should be developed for the ReliabilityFirst region. As a result, the standard drafting team added proposed Requirement R3 to BAL-502-RF-03 in response to the FERC directive. This change is justified because it codifies the documentation of this gap for the ReliabilityFirst region.

---

[31] NERC, 2015 Long-Term Reliability Assessment (Dec. 2015) http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2015LTRA%20-%20Final%20Report.pdf.

[32] NERC, 2014 Probabilistic Assessment (Apr. 2015) http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2014ProbA%20April%20Report%20Final_Final.pdf.

The standard drafting team also proposed several non-substantive changes to BAL-502-RF-03 to align the regional Reliability Standard with the updated format of other NERC Reliability Standards. The non-substantive changes include the following:

(1) Changed name from BAL-502-RFC-02 to BAL-502-RF-03;

(2) Updated the formatting of Section A (Introduction);

(3) Updated Effective Date Section;

(4) Added the term "and Measures" to Section B heading;

(5) Placed Measures immediately following the associated Requirements;

(6) Removed the "R" from all sub-requirements making them sub-parts;

(7) Updated section C (Compliance) to be consistent with NERC Reliability Standard template language;

(8) Renamed "Violation Severity Levels" Section to "Table of Compliance Elements";

(9) Updated "Table of Compliance Elements" to include "Time Horizons" and "VRFs";

(10) Added Sections D (Regional Variances), E (Interpretations), and F (Associated Documents) to the end of regional Reliability Standard;

(11) Changed bulleted items in R1.3.1, R1.3.2 and R1.4 to sub-parts to conform to standard practice; and

(12) Updated Version History to include ReliabilityFirst Board of Directors, NERC Board of Trustees, and FERC approval dates.

C. Enforceability of Proposed Regional Reliability Standard BAL-502-RF-03

The proposed regional Reliability Standard includes VRFs and VSLs. The VSLs provide guidance on the way that NERC will enforce the requirements of the proposed regional Reliability Standard. The VRFs are one of several elements used to determine an appropriate sanction when the associated requirement is violated. The VRFs assess the impact to reliability of violating a specific requirement. The VRFs and VSLs for the proposed regional Reliability Standard comport with NERC and Commission guidelines related to their assignment.

The proposed regional Reliability Standard also includes measures that support each requirement by clearly identifying what is required and how the requirement will be enforced. These measures help ensure that the requirements will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.[33]

V. EFFECTIVE DATE

NERC respectfully requests that the Commission approve the proposed regional Reliability Standard BAL-502-RF-03 and the retirement of BAL-502-RFC-02 to become effective as set forth in the proposed Implementation Plan, provided in Exhibit B hereto. The proposed effective date of the proposed regional Reliability Standard BAL-502-RF-03 is the first day of the first calendar quarter that is after the date that this regional Reliability Standard is approved by applicable regulatory authorities or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a Reliability Standard to go into effect.

VI. CONCLUSION

For the reasons set forth above, NERC respectfully requests that the Commission approve:

- the proposed regional Reliability Standard BAL-502-RF-03 in **Exhibit A**;
- the other associated elements in the regional Reliability Standard in **Exhibit A**, including the VRFs and VSLs (**Exhibits A and C)**;
- the retirement of existing regional Reliability Standard BAL-502-RFC-02; and

[33] Order No. 672 at P 327 ("There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. It should contain or be accompanied by an objective measure of compliance so that it can be enforced and so that enforcement can be applied in a consistent and non-preferential manner.").

- the Implementation Plan, included in **Exhibit B**.

Respectfully submitted,

/s/ Marisa Hecht

Jason Blake
General Counsel
Megan Gambrel
Senior Counsel
ReliabilityFirst Corporation
3 Summit Park Drive, Suite 600
Cleveland, OH 44131
(216) 503-0600
jason.blake@rfirst.org
megan.gambrel@rfirst.org

Counsel for the ReliabilityFirst Corporation

Shamai Elstein
Senior Counsel
Marisa Hecht
Counsel
North American Electric Reliability Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 400-3000
shamai.elstein@nerc.net
marisa.hecht@nerc.net

Counsel for the North American Electric Reliability Corporation

Date: September 7, 2017

Exhibit A

Proposed Regional Reliability Standard,

BAL-502-RF-03 – Planning Resource Adequacy Analysis, Assessment and Documentation

Exhibit A

Proposed Regional Reliability Standard,

BAL-502-RF-03 – Planning Resource Adequacy Analysis, Assessment and Documentation

Clean

A. Introduction

1. Title: **Planning Resource Adequacy Analysis, Assessment and Documentation**

2. Number: **BAL-502-RF-03**

3. Purpose: To establish common criteria, based on "one day in ten year" loss of Load expectation principles, for the analysis, assessment and documentation of Resource Adequacy for Load in the ReliabilityFirst Corporation (RF) region

4. Applicability

4.1 Functional Entities

4.1.1 Planning Coordinator

5. Effective Date:

5.1 BAL-502-RF-03 shall become effective on the first day of the first calendar quarter that is after the date that this standard is approved by applicable regulatory authorities or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect.

B. Requirements and Measures

R1 The Planning Coordinator shall perform and document a Resource Adequacy analysis annually. The Resource Adequacy analysis shall *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*:

1.1 Calculate a planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year[1] analyzed (per R1.2) being equal to 0.1. (This is comparable to a "one day in 10 year" criterion).

1.1.1 The utilization of Direct Control Load Management or curtailment of Interruptible Demand shall not contribute to the loss of Load probability.

1.1.2 The planning reserve margin developed from R1.1 shall be expressed as a percentage of the median[2] forecast peak Net Internal Demand (planning reserve margin).

1.2 Be performed or verified separately for each of the following planning years:

[1] The annual period over which the LOLE is measured, and the resulting resource requirements are established (June 1st through the following May 31st).

[2] The median forecast is expected to have a 50% probability of being too high and 50% probability of being too low (50:50).

1.2.1 Perform an analysis for Year One.

1.2.2 Perform an analysis or verification at a minimum for one year in the 2 through 5 year period and at a minimum one year in the 6 though 10 year period.

1.2.2.1 If the analysis is verified, the verification must be supported by current or past studies for the same planning year.

1.3 Include the following subject matter and documentation of its use:

1.3.1 Load forecast characteristics:

1.3.1.1 Median (50:50) forecast peak Load.

1.3.1.2 Load forecast uncertainty (reflects variability in the Load forecast due to weather and regional economic forecasts).

1.3.1.3 Load diversity.

1.3.1.4 Seasonal Load variations.

1.3.1.5 Daily demand modeling assumptions (firm, interruptible).

1.3.1.6 Contractual arrangements concerning curtailable/Interruptible Demand.

1.3.2 Resource characteristics:

1.3.2.1 Historic resource performance and any projected changes

1.3.2.2 Seasonal resource ratings

1.3.2.3 Modeling assumptions of firm capacity purchases from and sales to entities outside the Planning Coordinator area.

1.3.2.4 Resource planned outage schedules, deratings, and retirements.

1.3.2.5 Modeling assumptions of intermittent and energy limited resource such as wind and cogeneration.

1.3.2.6 Criteria for including planned resource additions in the analysis

1.3.3 Transmission limitations that prevent the delivery of generation reserves

1.3.3.1 Criteria for including planned Transmission Facility additions in the analysis

1.3.4 Assistance from other interconnected systems including multi-area assessment considering Transmission limitations into the study area.

1.4 Consider the following resource availability characteristics and document how and why they were included in the analysis or why they were not included:

1.4.1 Availability and deliverability of fuel.

1.4.2 Common mode outages that affect resource availability

1.4.3 Environmental or regulatory restrictions of resource availability.

1.4.4 Any other demand (Load) response programs not included in R1.3.1.

1.4.5 Sensitivity to resource outage rates.

1.4.6 Impacts of extreme weather/drought conditions that affect unit availability.

1.4.7 Modeling assumptions for emergency operation procedures used to make reserves available.

1.4.8 Market resources not committed to serving Load (uncommitted resources) within the Planning Coordinator area.

1.5 Consider Transmission maintenance outage schedules and document how and why they were included in the Resource Adequacy analysis or why they were not included

1.6 Document that capacity resources are appropriately accounted for in its Resource Adequacy analysis

1.7 Document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis

M1 Each Planning Coordinator shall possess the documentation that a valid Resource Adequacy analysis was performed or verified in accordance with R1

R2 The Planning Coordinator shall annually document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*.

2.1 This documentation shall cover each of the years in Year One through ten.

2.2 This documentation shall include the Planning Reserve margin calculated per requirement R1.1 for each of the three years in the analysis.

2.3 The documentation as specified per requirement R2.1 and R2.2 shall be publicly posted no later than 30 calendar days prior to the beginning of Year One.

M2 Each Planning Coordinator shall possess the documentation of its projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis on an annual basis in accordance with R2.

R3 The Planning Coordinator shall identify any gaps between the needed amount of planning reserves defined in Requirement R1, Part 1.1 and the projected planning reserves documented in Requirement R2 *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*.

M3 Each Planning Coordinator shall possess the documentation identifying any gaps between the needed amounts of planning reserves and projected planning reserves in accordance with R3.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

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

The Applicable Entity shall keep data or evidence to show compliance with Requirements R1 through R3, and Measures M1 through M3 from the most current and prior two years.

If an Applicable Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

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

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit
Self-Certification
Spot Checking

Compliance Investigation
Self-Reporting
Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	VIOLATION SEVERITY LEVEL			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Medium	The Planning Coordinator Resource Adequacy analysis failed to consider 1 or 2 of the Resource availability characteristics subcomponents under Requirement R1, Part 1.4 and documentation of how and why they were included in the analysis or why they were not included **OR** The Planning Coordinator Resource Adequacy analysis failed to consider Transmission maintenance outage schedules and document how and why they were included in the analysis or why they were not included per Requirement R1, Part 1.5	The Planning Coordinator Resource Adequacy analysis failed to express the planning reserve margin developed from Requirement R1, Part 1.1 as a percentage of the net Median forecast peak Load per Requirement R1, Part 1.1.2 **OR** The Planning Coordinator Resource Adequacy analysis failed to include 1 of the Load forecast Characteristics subcomponents under Requirement R1, Part 1.3.1 and documentation of its use **OR**	The Planning Coordinator Resource Adequacy analysis failed to be performed or verified separately for individual years of Year One through Year Ten per Requirement R1, Part 1.2 **OR** The Planning Coordinator failed to perform an analysis or verification for one year in the 2 through 5 year period or one year in the 6 though 10 year period or both per Requirement R1, Part 1.2.2 **OR** The Planning Coordinator Resource Adequacy analysis failed to include 2 or	The Planning Coordinator failed to perform and document a Resource Adequacy analysis annually per R1. **OR** The Planning Coordinator Resource Adequacy analysis failed to calculate a Planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year analyzed for each planning period being equal to 0.1 per Requirement R1, Part 1.1 **OR**

				The Planning Coordinator Resource Adequacy analysis failed to include 1 of the Resource Characteristics subcomponents under Requirement R1, Part 1.3.2 and documentation of its use **Or** The Planning Coordinator Resource Adequacy analysis failed to document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis per Requirement R1, Part 1.7	more of the Load forecast Characteristics subcomponents under Requirement R1, Part 1.3.1 and documentation of their use **OR** The Planning Coordinator Resource Adequacy analysis failed to include 2 or more of the Resource Characteristics subcomponents under Requirement R1, Part 1.3.2 and documentation of their use **OR** The Planning Coordinator Resource Adequacy analysis failed to include Transmission limitations and documentation of its use	The Planning Coordinator failed to perform an analysis for Year One per Requirement R1, Part 1.2.1

					per Requirement R1, Part 1.3.3 **OR** The Planning Coordinator Resource Adequacy analysis failed to include assistance from other interconnected systems and documentation of its use per Requirement R1, Part 1.3.4 **OR** The Planning Coordinator Resource Adequacy analysis failed to consider 3 or more Resource availability characteristics subcomponents under Requirement R1, Part 1.4 and documentation of how and why they were included in the analysis or why they were not included	

					OR The Planning Coordinator Resource Adequacy analysis failed to document that capacity resources are appropriately accounted for in its Resource Adequacy analysis per Requirement R1, Part 1.6	
R2	Long-term Planning	Lower	The Planning Coordinator failed to publicly post the documents as specified per requirement Requirement R2, Part 2.1 and Requirement R2, Part 2.2 later than 30 calendar days prior to the beginning of Year One per Requirement R2, Part 2.3	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for one of the years in the 2 through 10 year period per Requirement R2, Part 2.1. **OR** The Planning Coordinator failed to document the Planning	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for year 1 of the 10 year period per Requirement R2, Part 2.1. **OR** The Planning Coordinator failed to document the projected Load and resource	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis per Requirement R2, Part 2.

				Reserve margin calculated per requirement R1.1 for each of the three years in the analysis per Requirement R2, Part 2.2.	capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for two or more of the years in the 2 through 10 year period per Requirement R2, Part 2.1.	
R3	Long-term Planning	Lower	None	None	None	The Planning Coordinator failed to identify any gaps between the needed amount of planning reserves and the projected planning reserves, per R3

D. Regional Variances

None

E. Interpretations

None

F. Associated Documents

None

Version History

Version	Date	Action	Change Tracking
BAL-502-RFC-02	12/04/08	ReliabilityFirst Board Approved	
BAL-502-RFC-02	08/05/09	NERC BoT Approved	
BAL-502-RFC-02	03/17/11	FERC Approved	
BAL-502-RFC-03	06/01/17	ReliabilityFirst Board Approved	
BAL-502-RF-03	08/10/17	NERC BOT Approved	

Exhibit A

Proposed Regional Reliability Standard,

BAL-502-RF-03 – Planning Resource Adequacy Analysis, Assessment and Documentation

Redline

A. Introduction

1. Title: **Planning Resource Adequacy Analysis, Assessment and Documentation**

2. Number: **BAL-502-~~RFC-02~~RF-03**

3. Purpose: To establish common criteria, based on "one day in ten year" loss of Load expectation principles, for the analysis, assessment and documentation of Resource Adequacy for Load in the ReliabilityFirst Corporation (RF~~C~~) region

4. Applicability

4.1 Functional Entities

4.1.1 Planning Coordinator

5. Effective Date:

~~**5.1** Upon RFC Board approval~~

5.1 BAL-502-RF-03 shall become effective on the first day of the first calendar quarter that is after the date that this standard is approved by applicable regulatory authorities or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect.

B. Requirements and Measures

R1 The Planning Coordinator shall perform and document a Resource Adequacy analysis annually. The Resource Adequacy analysis shall *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*:

~~R1~~1.1 Calculate a planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year[1] analyzed (per R1.2) being equal to 0.1. (This is comparable to a "one day in 10 year" criterion).

~~R1~~1.1.1 The utilization of Direct Control Load Management or curtailment of Interruptible Demand shall not contribute to the loss of Load probability.

[1] The annual period over which the LOLE is measured, and the resulting resource requirements are established (June 1st through the following May 31st).

~~R1~~1.1.2 The planning reserve margin developed from R1.1 shall be expressed as a percentage of the median[2] forecast peak Net Internal Demand (planning reserve margin).

~~R1~~1.2 Be performed or verified separately for each of the following planning years:

~~R1~~1.2.1 Perform an analysis for Year One.

~~R1~~1.2.2 Perform an analysis or verification at a minimum for one year in the 2 through 5 year period and at a minimum one year in the 6 though 10 year period.

~~R1~~1.2.2.1 If the analysis is verified, the verification must be supported by current or past studies for the same planning year.

~~R1~~1.3 Include the following subject matter and documentation of its use:

~~R1~~1.3.1 Load forecast characteristics:

1.3.1.1 Median (50:50) forecast peak Load.

1.3.1.2 Load forecast uncertainty (reflects variability in the Load forecast due to weather and regional economic forecasts).

1.3.1.3 Load diversity.

1.3.1.4 Seasonal Load variations.

1.3.1.5 Daily demand modeling assumptions (firm, interruptible).

1.3.1.6 Contractual arrangements concerning curtailable/Interruptible Demand.

~~R1~~1.3.2 Resource characteristics:

1.3.2.1 Historic resource performance and any projected changes

1.3.2.2 Seasonal resource ratings

1.3.2.3 Modeling assumptions of firm capacity purchases from and sales to entities outside the Planning Coordinator area.

1.3.2.4 Resource planned outage schedules, deratings, and retirements.

[2] The median forecast is expected to have a 50% probability of being too high and 50% probability of being too low (50:50).

1.3.2.5 Modeling assumptions of intermittent and energy limited resource such as wind and cogeneration.

1.3.2.6 Criteria for including planned resource additions in the analysis

~~R1~~1.3.3 Transmission limitations that prevent the delivery of generation reserves

~~R1~~1.3.3.1 Criteria for including planned Transmission Facility additions in the analysis

~~R1~~1.3.4 Assistance from other interconnected systems including multi-area assessment considering Transmission limitations into the study area.

~~R1~~1.4 Consider the following resource availability characteristics and document how and why they were included in the analysis or why they were not included:

1.4.1 Availability and deliverability of fuel.

1.4.2 Common mode outages that affect resource availability

1.4.3 Environmental or regulatory restrictions of resource availability.

1.4.4 Any other demand (Load) response programs not included in R1.3.1.

1.4.5 Sensitivity to resource outage rates.

1.4.6 Impacts of extreme weather/drought conditions that affect unit availability.

1.4.7 Modeling assumptions for emergency operation procedures used to make reserves available.

1.4.8 Market resources not committed to serving Load (uncommitted resources) within the Planning Coordinator area.

~~R1~~1.5 Consider Transmission maintenance outage schedules and document how and why they were included in the Resource Adequacy analysis or why they were not included

~~R1~~1.6 Document that capacity resources are appropriately accounted for in its Resource Adequacy analysis

~~R1~~1.7 Document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis

M1 Each Planning Coordinator shall possess the documentation that a valid Resource Adequacy analysis was performed or verified in accordance with R1

R2 The Planning Coordinator shall annually document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*.

~~R2~~2.1 This documentation shall cover each of the years in Year One through ten.

~~R2~~2.2 This documentation shall include the Planning Reserve margin calculated per requirement R1.1 for each of the three years in the analysis.

~~R2~~2.3 The documentation as specified per requirement R2.1 and R2.2 shall be publicly posted no later than 30 calendar days prior to the beginning of Year One.

~~C. Measures~~

~~**M1** Each Planning Coordinator shall possess the documentation that a valid Resource Adequacy analysis was performed or verified in accordance with R1~~

M2 Each Planning Coordinator shall possess the documentation of its projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis on an annual basis in accordance with R2.

R3 The Planning Coordinator shall identify any gaps between the needed amount of planning reserves defined in Requirement R1, Part 1.1 and the projected planning reserves documented in Requirement R2 *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*.

M3 Each Planning Coordinator shall possess the documentation identifying any gaps between the needed amounts of planning reserves and projected planning reserves in accordance with R3.

~~D.~~C. Compliance

1. Compliance Monitoring Process

1.1. Compliance ~~Monitoring Responsibility~~Enforcement Authority

~~Compliance Monitor - Reliability~~*~~First~~* ~~Corporation~~

~~1.2. Compliance Monitoring Period and Reset Timeframe~~

~~One calendar year~~

~~Data~~As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

~~1.3.~~1.2. ~~Evidence~~ Retention

~~The Planning Coordinator shall retain information from the most current and prior two years.~~

~~The Compliance Monitor shall retain any audit data for five years.~~

~~2. Violation Severity Levels~~

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

The Applicable Entity shall keep data or evidence to show compliance with Requirements R1 through R3, and Measures M1 through M3 from the most current and prior two years.

If an Applicable Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

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

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit
Self-Certification
Spot Checking
Compliance Investigation
Self-Reporting
Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

~~Req.~~ Number R #	Time Horizon	VRF	VIOLATION SEVERITY LEVEL			
	~~LOWER~~	~~MODERATE~~	~~HIGH~~Lower VSL	~~SEVERE~~Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Medium	The Planning Coordinator Resource Adequacy analysis failed to consider 1 or 2 of the Resource availability characteristics subcomponents under ~~R1~~Requirement R1, Part 1.4 and documentation of how and why they were included in the analysis or why they were not included **OR** The Planning Coordinator Resource Adequacy analysis failed to consider Transmission maintenance outage schedules and document how and why they were included in the analysis or why they were not included per ~~R1~~Requirement R1, Part 1.5	The Planning Coordinator Resource Adequacy analysis failed to express the planning reserve margin developed from Requirement R1, Part 1.1 as a percentage of the net Median forecast peak Load per ~~R1~~Requirement R1, Part 1.1.2 **OR** The Planning Coordinator Resource Adequacy analysis failed to include 1 of the Load forecast Characteristics subcomponents under ~~R1~~Requirement R1, Part 1.3.1 and documentation of its use **OR**	The Planning Coordinator Resource Adequacy analysis failed to be performed or verified separately for individual years of Year One through Year Ten per ~~R1~~Requirement R1, Part 1.2 **OR** The Planning Coordinator failed to perform an analysis or verification for one year in the 2 through 5 year period or one year in the 6 though 10 year period or both per Requirement R1, Part 1.2.2 **OR** The Planning Coordinator Resource Adequacy analysis failed to include 2 or	The Planning Coordinator failed to perform and document a Resource Adequacy analysis annually per R1. **OR** The Planning Coordinator Resource Adequacy analysis failed to calculate a Planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year analyzed for each planning period being equal to 0.1 per ~~R1~~Requirement R1, Part 1.1 **OR**

				The Planning Coordinator Resource Adequacy analysis failed to include 1 of the Resource Characteristics subcomponents under ~~R1~~Requirement R1, Part 1.3.2 and documentation of its use **Or** The Planning Coordinator Resource Adequacy analysis failed to document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis per ~~R1~~Requirement R1, Part 1.7	more of the Load forecast Characteristics subcomponents under ~~R1~~Requirement R1, Part 1.3.1 and documentation of their use **OR** The Planning Coordinator Resource Adequacy analysis failed to include 2 or more of the Resource Characteristics subcomponents under ~~R1~~Requirement R1, Part 1.3.2 and documentation of their use **OR** The Planning Coordinator Resource Adequacy analysis failed to include Transmission limitations and documentation of its use	The Planning Coordinator failed to perform an analysis for Year One per ~~R1~~Requirement R1, Part 1.2.1

					per ~~R1~~Requirement R1, Part 1.3.3 **OR** The Planning Coordinator Resource Adequacy analysis failed to include assistance from other interconnected systems and documentation of its use per ~~R1~~Requirement R1, Part 1.3.4 **OR** The Planning Coordinator Resource Adequacy analysis failed to consider 3 or more Resource availability characteristics subcomponents under ~~R1~~Requirement R1, Part 1.4 and documentation of how and why they were included in the analysis	

					or why they were not included **OR** The Planning Coordinator Resource Adequacy analysis failed to document that capacity resources are appropriately accounted for in its Resource Adequacy analysis per Requirement R1, Part 1.6	
R2	Long-term Planning	Lower	The Planning Coordinator failed to publicly post the documents as specified per requirement Requirement R2, Part 2.1 and Requirement R2, Part 2.2 later than 30 calendar days prior to the beginning of Year One per ~~R2~~Requirement R2, Part 2.3	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for one of the years in the 2 through 10 year period per ~~R2~~Requirement R2, Part 2.1. **OR**	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for year 1 of the 10 year period per ~~R2~~Requirement R2, Part 2.1. **OR**	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis per Requirement R2, Part 2.

				The Planning Coordinator failed to document the Planning Reserve margin calculated per requirement R1.1 for each of the three years in the analysis per ~~R2~~Requirement R2, Part 2.2.	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for two or more of the years in the 2 through 10 year period per Requirement R2, Part 2.1.	
R3	Long-term Planning	Lower	None	None	None	The Planning Coordinator failed to identify any gaps between the needed amount of planning reserves and the projected planning reserves, per R3

~~**Definitions:**~~

~~**Resource Adequacy** - the ability of supply-side and demand-side resources to meet the aggregate electrical demand (including losses).~~

~~**Net Internal Demand** - Total of all end-use customer demand and electric system losses within specified metered boundaries, less Direct Control Load Management and Interruptible Demand.~~

~~**Peak Period** - A period consisting of two (2) or more calendar months but less than seven (7) calendar months, which includes the period during which the responsible entity's annual peak demand is expected to occur~~

~~**Year One** – The planning year that begins with the upcoming annual Peak Period.~~

~~**The following definitions were extracted from the February 12th, 2008 NERC Glossary of Terms:**~~

~~**Direct Control Load Management** – Demand-Side Management that is under the direct control of the system operator. DCLM may control the electric supply to individual appliances or equipment on customer premises. DCLM as defined here does not include Interruptible Demand.~~

~~**Facility** – 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.)~~

~~**Interruptible Demand** – Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment.~~

~~**Load** – An end-use device or customer that receives power from the electric system.~~

~~**Transmission** – An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.~~

D. Regional Variances

None

E. Interpretations

None

F. Associated Documents

None

Version History

Version	Date	Action	Change Tracking
~~BAL-502-RFC-02 1st Draft~~	~~06/24/08 Through 07/23/08~~	~~Posted for 1st Comment Period~~	
~~BAL-502-RFC-02 2nd Draft~~	~~08/18/08 Through 09/16/08~~	~~Posted for 2nd Comment Period~~	
~~BAL-502-RFC-02 3rd Draft~~	~~10/16/08 Through 10/30/08~~	~~Posted for 15-Day Category Ballot~~	
BAL-502-RFC-02	12/04/08	ReliabilityFirst Board Approved	
~~BAL-502-RFC-02~~	~~06/08/09~~	~~"Planning Reserve" changed to "planning reserve" in R2.2.~~	~~Errata~~
BAL-502-RFC-02	08/05/09	NERC BoT Approved ~~by NERC Board of Trustees~~	
BAL-502-RFC-02	03/17/11	~~Order issued by FERC approving BAL-502-RFC-02 (approval effective 5/23/11)~~FERC Approved	
BAL-502-RFC-03	06/01/17	ReliabilityFirst Board Approved	
BAL-502-RF-03	08/10/17	NERC BOT Approved	

Exhibit B

Implementation Plan for Proposed Regional Reliability Standard BAL-502-RF-03 - Planning Resource Adequacy Analysis, Assessment and Documentation

Planning Resource Adequacy Analysis, Assessment and Documentation (BAL-502-RF-03) Implementation Plan

Requested Approvals

- None

Requested Retirements

- BAL-502-RFC-02

Prerequisite Approval

- None

Revisions to Defined Terms in the NERC Glossary

- None

Effective Date

- BAL-502-RF-03 shall become effective on the first day of the first calendar quarter that is after the date that this standard is approved by applicable regulatory authorities or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect.

Exhibit C

Order No. 672 Criteria for Proposed Regional Reliability Standard BAL-502-RF-03 – Planning Resource Adequacy Analysis, Assessment and Documentation

EXHIBIT C

Order No. 672 Criteria for Proposed BAL-502-RF-03

In Order No. 672,[1] the Commission identified a number of criteria it will use to analyze Reliability Standards proposed for approval to ensure they are just, reasonable, not unduly discriminatory or preferential, and in the public interest. The discussion below identifies these factors and explains how the proposed regional Reliability Standard has met or exceeded the criteria:

1. **Proposed Reliability Standards must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve that goal.[2]**

The purpose of BAL-502-RF-03 is to establish common criteria, based on "one day in ten year" loss of Load expectation principles, for the analysis, assessment, and documentation of Resource Adequacy for Load in the ReliabilityFirst region. The proposed BAL-502-RF-03 regional Reliability Standard is technically sound as it continues to meet the same performance of regional Reliability Standard BAL-502-RFC-

---

[1] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[2] Order No. 672 at P 321. The proposed Reliability Standard must address a reliability concern that falls within the requirements of section 215 of the FPA. That is, it must provide for the reliable operation of Bulk-Power System facilities. It may not extend beyond reliable operation of such facilities or apply to other facilities. Such facilities include all those necessary for operating an interconnected electric energy transmission network, or any portion of that network, including control systems. The proposed Reliability Standard may apply to any design of planned additions or modifications of such facilities that is necessary to provide for reliable operation. It may also apply to Cybersecurity protection.

Order No. 672 at P 324. The proposed Reliability Standard must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve this goal. Although any person may propose a topic for a Reliability Standard to the ERO, in the ERO's process, the specific proposed Reliability Standard should be developed initially by persons within the electric power industry and community with a high level of technical expertise and be based on sound technical and engineering criteria. It should be based on actual data and lessons learned from past operating incidents, where appropriate. The process for ERO approval of a proposed Reliability Standard should be fair and open to all interested persons.

02.[3] Proposed BAL-502-RF-03 is more stringent than continent-wide Reliability Standards because the NERC Reliability Standards do not presently address assessment of resource adequacy in the planning horizon.

2. Proposed Reliability Standards must be applicable only to users, owners and operators of the bulk power system, and must be clear and unambiguous as to what is required and who is required to comply.[4]

Proposed BAL-502-RF-03 is only applicable to Planning Coordinators within the ReliabilityFirst region. As explained in greater detail in the petition, the proposed regional Reliability Standard includes three requirements that specify what the Planning Coordinators need to do in order to comply.

3. A proposed Reliability Standard must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation.[5]

Proposed BAL-502-RF-03 does not have any substantive changes to the VRFs and VSLs approved in BAL-502-RFC-02, with the exception of the addition of the VRF and VSL for Requirement R3. The proposed regional Reliability Standard continues to comport with NERC and Commission guidelines. The assignment of the severity level for each VSL is consistent with the corresponding Requirement and the VSLs should ensure uniformity and consistency in the determination of penalties. The VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. For these reasons, the proposed

---

[3] BAL-502-RFC-02 was approved by the Commission on March 17, 2011. *See Planning Resource Adequacy Assessment Reliability Standard*, Order No. 747, 134 FERC ¶ 61,212 (2011).

[4] Order No. 672 at P 322. The proposed Reliability Standard may impose a requirement on any user, owner, or operator of such facilities, but not on others.

Order No. 672 at P 325. The proposed Reliability Standard should be clear and unambiguous regarding what is required and who is required to comply. Users, owners, and operators of the Bulk-Power System must know what they are required to do to maintain reliability.

[5] Order No. 672 at P 326. The possible consequences, including range of possible penalties, for violating a proposed Reliability Standard should be clear and understandable by those who must comply.

regional Reliability Standard includes clear and understandable consequences in accordance with Order No. 672. Upon approval by the Commission, the ranges of penalties for violations will continue to be based on the applicable VRF and VSL in accordance with the sanctions table and the supporting penalty determination process described in the Commission-approved NERC Sanction Guidelines, Appendix 4B to the NERC Rules of Procedure.

4. A proposed Reliability Standard must identify clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non-preferential manner. [6]

Proposed BAL-502-RF-03 identifies clear and objective criterion or Measures for compliance so that it can be enforced in a consistent and non-preferential manner. The regional Reliability Standard contains individual Measures that support the regional difference's Requirements by plainly identifying how the Requirements will be assessed and enforced. These Measures continue to ensure that the Requirements will be assessed and enforced in a clear, consistent, and non-preferential manner, without prejudice to any party.

5. Proposed Reliability Standards should achieve a reliability goal effectively and efficiently — but do not necessarily have to reflect "best practices" without regard to implementation cost or historical regional infrastructure design.[7]

Proposed BAL-502-RF-03 achieves its reliability goals effectively and efficiently. The proposed standard adds a requirement to document any identified gaps between

---

[6] Order No. 672 at P 327. There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. It should contain or be accompanied by an objective measure of compliance so that it can be enforced and so that enforcement can be applied in a consistent and non-preferential manner.

[7] Order No. 672 at P 328. The proposed Reliability Standard does not necessarily have to reflect the optimal method, or "best practice," for achieving its reliability goal without regard to implementation cost or historical regional infrastructure design. It should however achieve its reliability goal effectively and efficiently.

needed planning reserves and projected planning but does not require a registered entity to install additional generation or transmission capacity.

6. Proposed Reliability Standards cannot be "lowest common denominator," *i.e.*, cannot reflect a compromise that does not adequately protect Bulk-Power System reliability. Proposed Reliability Standards can consider costs to implement for smaller entities, but not at consequences of less than excellence in operating system reliability.[8]

Proposed BAL-502-RF-03 does not reflect a compromise that does not adequately protect Bulk-Power System reliability.

7. Proposed Reliability Standards must be designed to apply throughout North America to the maximum extent achievable with a single Reliability Standard while not favoring one geographic area or regional model. It should take into account regional variations in the organization and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.[9]

---

[8] Order No. 672 at P 329. The proposed Reliability Standard must not simply reflect a compromise in the ERO's Reliability Standard development process based on the least effective North American practice — the so-called "lowest common denominator" — if such practice does not adequately protect Bulk-Power System reliability. Although FERC will give due weight to the technical expertise of the ERO, we will not hesitate to remand a proposed Reliability Standard if we are convinced it is not adequate to protect reliability.

Order No. 672 at P 330. A proposed Reliability Standard may take into account the size of the entity that must comply with the Reliability Standard and the cost to those entities of implementing the proposed Reliability Standard. However, the ERO should not propose a "lowest common denominator" Reliability Standard that would achieve less than excellence in operating system reliability solely to protect against reasonable expenses for supporting this vital national infrastructure. For example, a small owner or operator of the Bulk-Power System must bear the cost of complying with each Reliability Standard that applies to it.

[9] Order No. 672 at P 331. A proposed Reliability Standard should be designed to apply throughout the interconnected North American Bulk-Power System, to the maximum extent this is achievable with a single Reliability Standard. The proposed Reliability Standard should not be based on a single geographic or regional model but should take into account geographic variations in grid characteristics, terrain, weather, and other such factors; it should also take into account regional variations in the organizational and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.

As a regional Reliability Standard, proposed BAL-502-RF-03 meets the requirements for regional Reliability Standards as discussed in the petition and will be enforceable for registered entities within the ReliabilityFirst region.

8. Proposed Reliability Standards should cause no undue negative effect on competition or restriction of the grid beyond any restriction necessary for reliability.[10]

The proposed regional Reliability Standard does not make any substantive changes to the existing Commission-approved regional Reliability Standard other than the addition of a Requirement.

9. The implementation time for the proposed Reliability Standard is reasonable.[11]

The implementation time for the proposed regional Reliability Standard is reasonable. Historically, the two Planning Coordinators within the ReliabilityFirst region have already been identifying this gap via a number of public reports. As a result, an effective date of the first day of the first calendar quarter that is after the date that this standard is approved by applicable regulatory authorities or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect is appropriate.

10. The Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard

---

[10] Order No. 672 at P 332. As directed by section 215 of the FPA, FERC itself will give special attention to the effect of a proposed Reliability Standard on competition. The ERO should attempt to develop a proposed Reliability Standard that has no undue negative effect on competition. Among other possible considerations, a proposed Reliability Standard should not unreasonably restrict available transmission capability on the Bulk-Power System beyond any restriction necessary for reliability and should not limit use of the Bulk-Power System in an unduly preferential manner. It should not create an undue advantage for one competitor over another.

[11] Order No. 672 at P 333. In considering whether a proposed Reliability Standard is just and reasonable, FERC will consider also the timetable for implementation of the new requirements, including how the proposal balances any urgency in the need to implement it against the reasonableness of the time allowed for those who must comply to develop the necessary procedures, software, facilities, staffing or other relevant capability.

development process.[12]

The proposed regional Reliability Standard was developed in accordance with NERC's and ReliabilityFirst's Commission-approved processes for developing and approving Reliability Standards. ReliabilityFirst develops regional Reliability Standards in accordance with the ReliabilityFirst Reliability Standards Development Procedure. For more detail, please see the complete development history included as Exhibit D.

11. NERC must explain any balancing of vital public interests in the development of proposed Reliability Standards.[13]

NERC and ReliabilityFirst have not identified competing vital public interests with respect to the request for approval of the regional Reliability Standard, and no comments were received during the development of the regional Reliability Standard indicating conflicts with other vital public interests.

12. Proposed Reliability Standards must consider any other appropriate factors.[14]

No other factors relevant to whether the proposed regional Reliability Standard is just and reasonable were identified.

---

[12] Order No. 672 at P 334. Further, in considering whether a proposed Reliability Standard meets the legal standard of review, we will entertain comments about whether the ERO implemented its Commission-approved Reliability Standard development process for the development of the particular proposed Reliability Standard in a proper manner, especially whether the process was open and fair. However, we caution that we will not be sympathetic to arguments by interested parties that choose, for whatever reason, not to participate in the ERO's Reliability Standard development process if it is conducted in good faith in accordance with the procedures approved by FERC.

[13] Order No. 672 at P 335. Finally, we understand that at times development of a proposed Reliability Standard may require that a particular reliability goal must be balanced against other vital public interests, such as environmental, social and other goals. We expect the ERO to explain any such balancing in its application for approval of a proposed Reliability Standard.

[14] Order No. 672 at P 323. In considering whether a proposed Reliability Standard is just and reasonable, we will consider the following general factors, as well as other factors that are appropriate for the particular Reliability Standard proposed.

Exhibit D

Summary of Development History and Complete Record of Development

Exhibit D

Summary of Development

Summary of Development History

The development record for proposed regional Reliability Standard BAL-502-RF-03 is summarized below.[1]

I. Overview of the Standard Drafting Team

When evaluating a proposed Reliability Standard, the Commission is expected to give "due weight" to the technical expertise of the ERO.[2] The technical expertise of the ERO is derived from the standard drafting team approved by the ReliabilityFirst Standards Committee to lead each project in accordance with Step 2 of the ReliabilityFirst Reliability Standards Development Procedure.[3] For this project, the standard drafting team consisted of industry experts, all with a diverse set of experiences. A roster of the Planning Resource Adequacy Analysis, Assessment, and Documentation standard drafting team members is included in Exhibit E.

II. Standard Development History

A. Five-year Periodic Review

ReliabilityFirst conducted a five-year review comment posting period from February 29, 2016 through March 9, 2016, to which six individuals responded. All six individual provided responses suggesting that the regional Reliability Standard BAL-502-RFC-02 be reaffirmed. The reaffirmation includes addressing two FERC directives from FERC Order No. 747.

B. Standard Authorization Request Development

Revisions to BAL-502-RFC-02 were initiated on March 31, 2016 with the receipt of a draft Standard Authorization Request ("SAR"). The ReliabilityFirst Standards Committee authorized

---

[1] The development web page for BAL-502-RF-03 is available at https://rfirst.org/standards/BAL502RFC03/Pages/BAL-502-RFC-03.aspx'.

[2] Section 215(d)(2) of the Federal Power Act; 16 U.S.C. §824(d) (2) (2012).

[3] The ReliabilityFirst Reliability Standards Development Procedure is available at https://rfirst.org/standards/Documents/Reliability%20Standards%20Developmental%20Procedure.pdf.

BAL-502-RF-03 for development on April 12, 2016. The draft SAR was posted for a 30-day comment period from April 11, 2016 through May 10, 2016. The final SAR was posted on May 12, 2016.

C. First Posting – Comment Period

On August 29, 2016, the ReliabilityFirst Standards Committee approved posting proposed regional Reliability Standard BAL-502-RF-03 for a 30-day public comment period. Proposed regional Reliability Standard BAL-502-RF-03 was posted for a 30-day public comment period from September 12, 2016 through October 11, 2016. ReliabilityFirst received comments from two individuals. Based on the comments received, the standard drafting team determined to make non-substantive changes to the proposed standard.[4]

D. Pre-Ballot Posting and Category Ballot

Proposed regional Reliability Standard was posted for 15 days from January 3, 2017 through January 17, 2017 prior to category ballot. Thirty-one individuals joined the ballot pool, which was formed from September 12, 2016 through January 9, 2017. A 15-day Category Ballot was conducted from January 18, 2017 through February 1, 2017. Twenty-eight individuals cast votes, reaching quorum at 93 percent. The standard received requisite approval of two-thirds or greater affirmative majority of votes for each category. Because at least one negative vote with comment during the initial ballot was cast, draft BAL-502-RF-03 standard was posted for a 10-day Recirculation Ballot.[5]

---

[4] The Consideration of Comments for Posting 1 is available at https://www.rfirst.org/standards/BAL502RFC03/SupportingDocuments/BAL-502-RF-03_First_Comment_and_Responses_102016_v2.pdf.

[5] The Initial Category Ballot Results are available at https://rfirst.org/standards/BAL502RFC03/SupportingDocuments/BAL-502-RF-03_Category_Ballot_Results_020117.pdf.

E. Recirculation Ballot

ReliabilityFirst conducted a 10-day Recirculation Ballot from February 6, 2017 through February 15, 2017. Twenty-eight individuals cast votes, reaching quorum at 93 percent. The standard received requisite approval of two-thirds or greater affirmative majority of votes for each category.[6]

F. ReliabilityFirst Board of Directors Approval

ReliabilityFirst posted the standard for 30 days from February 22, 2017 through March 23, 2017 prior to approval by the ReliabilityFirst Board of Directors. The ReliabilityFirst Board of Directors approved the standard on June 1, 2017.

G. NERC Comment Period and Board of Trustees Approval

NERC posted proposed regional Reliability Standard BAL-502-RF-03 for a 45-day public comment period from April 28, 2017 to June 12, 2017.[7] The NERC Board of Trustees adopted proposed regional Reliability Standard BAL-502-RF-03 on August 10, 2017.[8]

---

[6] The Recirculation Ballot results are available at https://rfirst.org/standards/BAL502RFC03/SupportingDocuments/BAL-502-RF-03_Recirculation_Ballot_Results_021517.pdf.

[7] The NERC web page for regional Reliability Standards Under Development is available at http://www.nerc.com/pa/Stand/Pages/RegionalReliabilityStandardsUnderDevelopment.aspx.

[8] NERC, *Board of Trustees Agenda Package*, Agenda Item 9c (BAL-502-RF-03 Planning Resource Adequacy Analysis, Assessment, and Documentation), *available at* http://www.nerc.com/gov/bot/Agenda%20highlights%20and%20Mintues%202013/Board_Open_Meeting_August_10_2017_Agenda_Package_v2%20(002).pdf.

Exhibit D

Complete Record of Development

Reliability First (RF)				
BAL-502-RF-03	Planning Resource Adequacy Analysis, Assessment and Documentation	Standard Under Development	04/28/17 - 06/12/17	BAL-502-RF-03 Clean (39) | Redline (40) Info (41) Submit Comments Unofficial Comment Form (Word) (42) Comments Received (43)

Detailed Information

Posted Document	Supporting Documents	Industry Comments	Comments
BAL-502-RF-03 (37) 08/10/2017	• Implementation Plan (38)		NERC BoT Approved: 08/10/17.
BAL-502-RF-03 (35) 06/01/2017	• Implementation Plan (36)		RF Board Approved: 06/01/17.
Draft BAL-Draft BAL-502-RF-03 (32) 02/22/2017	• Draft Implementation Plan (33) • BAL-502-RF-03 Recirculation Ballot Results and Comments (34)		Posted for 30-Days Prior to Board Action. 02/22/17 thru 03/23/17.
Draft BAL-502-RF-03 (28) 02/06/2017	• Draft Implementation Plan (29) • BAL-502-RF-03 Initial Ballot Results and Comments (30)	02/06/17 thru 02/15/17 Recirculation Ballot Announcement (31)	Posted for 10-Day Recirculation Ballot. 02/06/17 thru 02/15/17.
Draft BAL-502-RF-03 (24) 01/18/2017	• Draft Implementation Plan (25)	01/18/2017 thru 02/01/2017	Posted for 15-Days Category Ballot. 01/18/17 thru 02/01/17.

		Category Ballot Announcement (26) BAL-502-RF-03 Ballot Pool (27)	
Draft BAL-502-RF-03 (18) 01/03/2017	• Draft BAL-502-RF-03 (Redline) (19) • BAL-502-RFC-02 Compared to Draft BAL-502-RFC-03 (Redline) (20) • Draft Implementation Plan (21)	01/03/2017 thru 01/17/2017 Join BAL-502-RF-03 Ballot Pool (22) 15-Day Pre-Ballot Announcement (23)	Posted for 15-Days prior to Category Ballot. 01/03/17 thru 01/17/17. (Ballot Pool closes on 01/09/17.)
Draft BAL-502-RF-03 (9) 09/12/2016	• Draft BAL-502-RF-03 (Redline) (10) • Draft Implementation Plan (11) • Perceived Reliability Impact (12) • Impact on Neighboring Regions (13) • Changes Between Draft BAL-502-RFC-03 and BAL-502-RFC-02 Standards (14) • 1st Posting Questions (15)	09/12/2016 thru 10/11/2016 Review Comments and Responses (16) Join BAL-502-RF-03 Ballot Pool (17)	Posted for 1st 30-Day Comment Period. 09/12/2016 thru 10/11/2016.
Roster (8) 06/15/2016			Drafting Team Formed
Final SAR (6) 05/12/2016	• Drafting Team Nomination Form (7)		Request for Standard Drafting Team Nominations: 05/16/2016 thru 06/06/2016.
Draft SAR (1) 04/11/2016	• Announcement (2) • Stakeholder Comment Question (3) • BAL-502-RFC-02 Standard (4)	04/11/16 thru 05/10/16 Consideration of Comments (5)	The BAL-502-RFC-03 SAR is currently posted for a 30-day comment period. 04/11/16 thru 05/10/16.

*The numbers in red correspond to the documents included in this exhibit.

Standard Authorization Request

The SC shall be responsible for implementing and maintaining this form as needed to support the information requirements of the standards development process in this Procedure. Changes to this form are considered minor, and therefore subject to only the approval of the SC.

ReliabilityFirst Standard Authorization Request Form

ReliabilityFirst will complete
ID - BAL-503-RFC-03
Authorized for Posting - 03/31/16
Authorized for Development - TBD

Title of Proposed Standard: Planning Resource Adequacy Analysis, Assessment and Documentation
Request Date: 03/31/16

SAR Originator Information

	SAR Type (Check box for one of these selections.)	
Name: Anthony Jablonski		
Company: ReliabilityFirst	☐	New Standard
Telephone: 216-503-0693	☒	Revision to Existing Standard
Fax:	☐	Withdrawal of Existing Standard
E-mail: Anthony.Jablonski@rfist.org	☐	Urgent Action

Purpose (Provide one or two sentences.)
The purpose of this SAR is to initiate actions to revise the existing ReliabilityFirst Planning Resource Adequacy Analysis, Assessment and Documentation (BAL-502-RFC-02) Standard to address two FERC Directives as noted in FERC Order No 747 (FERC Order initially approving the Standard). Miscellaneous non-substantive format changes such as, but not limited to, reclassifying "sub-requirements" to "parts" will be considered as well.

Industry Need (Provide one or two sentences.)
The ReliabilityFirst Planning Resource Adequacy Analysis, Assessment and Documentation (BAL-502-RFC-02) Standard was approved as a Regional Reliability Standard by the Commission in Order No 747 on March 17, 2011 and became enforceable on May 23, 2011. The BAL-502-RFC-02 Standard establishes requirements for Planning Authorities/Coordinators in the

ReliabilityFirst region regarding resource adequacy assessment, which subject matter is not currently addressed in NERC's continent-wide Reliability Standards. The Commission also approves four regional reliability definitions related to the approved regional Reliability Standard and the violation risk factors and violation severity levels assigned to the BAL-502-RFC-02 Requirements.

The BAL-502-RFC-02 Standard contains the following two main requirements. Requirement R1 requires each Planning Coordinator in the ReliabilityFirst footprint to perform and document an annual resource adequacy analysis. The sub-requirements of Requirement R1 set forth the criteria to be used for the resource adequacy analysis. Requirement R2 requires each Planning Coordinator to annually document the projected load and resource capability for each area and transmission constrained sub-area identified in the analysis. The sub-requirements of Requirement R2 set forth the specific documentation requirements.

At the time of approval, the Commission directed ReliabilityFirst, at the time it conducts its scheduled five year review, to (1) add time horizons to the two main requirements, and (2) consider modifying the regional Reliability Standard to include a requirement that the planning coordinators identify any gap between the needed amount of planning reserves defined in Requirement R1.1 and the planning reserves determined from the resource adequacy analysis.

ReliabilityFirst conducted a five year review comment posting period (February 29, 2016 through March 9, 2016) in which six individuals responded. All six individual provided responses indicating that they believe the BAL-502-RFC-02 should be reaffirmed (which includes a process to respond to the FERC directives).

Brief Description (A few sentences or a paragraph.)
The Standard Drafting Team (SDT) will review the two main requirements and shall add Time Horizons to each of the Requirements.

The SDT will consider modifying the BAL-502-RFC-02 Standard to include a requirement that the Planning Coordinators identify any gap between the needed amount of planning reserves defined in Requirement R1.1 and the planning reserves determined from the resource adequacy analysis.

The SDT will also consider miscellaneous non-substantive formatting changes such as, but not limited to, reclassifying "sub-requirements" to "parts".

Reliability Functions

The Standard will Apply to the Following Functions (Check box for each one that applies.)

☐	Reliability Authority	Ensures the reliability of the bulk transmission system within its Reliability Authority area. This is the highest reliability authority.

☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within its metered boundary and supports system frequency in real time
☐	Generator Owner	Owns and maintains generating units
☐	Interchange Authority	Authorizes valid and balanced Interchange Schedules
☒	Planning Authority/Planning Coordinator	Plans the BPS
☐	Resource Planner	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
☐	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
☐	Transmission Service Provider	Provides transmission services to qualified market participants under applicable transmission service agreements
☐	Transmission Owner	Owns transmission facilities
☐	Transmission Operator	Operates and maintains the transmission facilities, and executes switching orders
☐	Distribution Provider	Provides and operates the “wires” between the transmission system and the customer
☐	Generator Operator	Operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services
☐	Purchasing-Selling Entity	The function of purchasing or selling energy, capacity and all necessary Interconnected Operations Services as required
☐	Load-Serving Entity	Secures energy and transmission (and related generation services) to serve the end user
☐	Market Operator	Integrates energy, capacity, balancing, and transmission resources to achieve an economic, reliability-constrained dispatch of resources. The dispatch may be either cost-based or bid-based
☐	Regional Reliability Organizations	An entity that ensures that a defined area of the BPS is reliable, adequate and secure. A member of the North American Electric Reliability Council. The Regional

		Reliability Organization can serve as the Compliance Monitor

NOTE: The SDT may find it necessary to modify the initial reliability function responsibility assignment as a result of the standards development and comments received.

Reliability Principles

Applicable Reliability Principles (Check box for all that apply.)	
☒	1. Interconnected BPS 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 BPS 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 BPS 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 BPS 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 BPS.
☐	6. Personnel responsible for planning and operating interconnected BPS shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected BPS shall be assessed, monitored, and maintained on a wide-area basis.

Market Interface Principles

Does the proposed Standard comply with all of the following Market Interface Principles?	
Recognizing that reliability is an essential requirement of a robust North American economy:	
☒yes or ☐no	1. A reliability standard shall not give any market participant an unfair competitive advantage.
☒yes or ☐no	2. A reliability standard shall neither mandate nor prohibit any specific market structure.

☒yes or ☐no	3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.
☒yes or ☐no	4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.

Detailed Description *(*Provide enough detail so that an independent entity familiar with the industry could draft a Standard based on this description.*)*

The SDT will review the two main requirements and shall add Time Horizons to each of the Requirements. The SDT shall review the five Time Horizons listed below and determine which Time Horizon is appropriate for each Requirement:

1. Long-term Planning – a planning horizon of one year or longer.
2. Operations Planning – operating and resource plans from day-ahead up to and including seasonal.
3. Same-day Operations – routine actions required within the timeframe of a day, but not real-time.
4. Real-time Operations – actions required within one hour or less to preserve the reliability of the bulk electric system.
5. Operations Assessment – follow-up evaluations and reporting of real-time operations.

The STD will consider modifying the BAL-502-RFC-02 Standard to include a requirement that the planning coordinators identify any gap between the needed amount of planning reserves defined in Requirement R1.1 and the planning reserves determined from the resource adequacy analysis. This new requirement will be a documentation requirement only and will not require entities to install additional generation or transmission capacity.

- If the SDT decides to not include a new requirement after their consideration, the SDT shall develop a technical justification as to why a new requirement was not included.
- If the SDT decides to include a new requirement after their consideration, the Standards Drafting Team shall also develop associated Measures, Violation Risk Factors, Violation Severity Levels and Time Horizons.

The SDT will also review the Standard and consider miscellaneous non-substantive formatting changes such as, but not limited to, reclassifying “sub-requirements” to “parts”.

Related Standards (NERC and Regional)

Standard No.	Explanation
BAL-502-RFC-02	This Standard was approved by the FERC on March 23, 2011

Related SARs

SAR ID	Explanation

Implementation Plan

Description *(Provide plans for the implementation of the proposed standard, including any known systems or training requirements. Include the reliability risk(s) associated with the violation that the standard will mitigate, and the costs associated with implementation.)*
Proposed Implementation days after Board adoption or **on (date):**

Assignments

	Assignment
Team Members	
ReliabilityFirst *Staff*	

Announcement: Planning Resource Adequacy Analysis, Assessment and Documentation SAR Posted for 30-Day Comment Period Beginning April 11, 2016

On March 31, 2016, the ReliabilityFirst Standards Committee (SC) unanimously agreed to post the Planning Resource Adequacy Analysis, Assessment and Documentation Standards Authorization Request (SAR) for the required 30-Day comment period. Per the Standards Development Procedure, the SAR is publically noticed and posted for the required 30-Day comment period beginning **April 11, 2016 through May 10, 2016**. Following the 30-Day comment period, the ReliabilityFirst Standards Committee will review all comments and take action to move the SAR into the developmental stage.

The purpose of this SAR is to initiate actions to revise the existing ReliabilityFirst Planning Resource Adequacy Analysis, Assessment and Documentation (BAL-502-RFC-02) Standard to address two FERC Directives as noted in FERC Order No 747 (FERC Order initially approving the Standard). The two FERC directives include (1) add time horizons to the two main requirements, and (2) consider modifying the regional Reliability Standard to include a requirement that the planning coordinators identify any gap between the needed amount of planning reserves defined in Requirement R1.1 and the planning reserves determined from the resource adequacy analysis. Miscellaneous non-substantive format changes such as, but not limited to, reclassifying "sub-requirements" to "parts" will be considered as well.

The three main actions noted within the SAR include the following:

1. The Standard Drafting Team (SDT) will review the two main requirements and shall add Time Horizons to each of the Requirements
2. The STD will consider modifying the BAL-502-RFC-02 Standard to include a requirement that the planning coordinators identify any gap between the needed amount of planning reserves defined in Requirement R1.1 and the planning reserves determined from the resource adequacy analysis.
3. The SDT will also review the Standard and consider miscellaneous non-substantive formatting changes such as, but not limited to, reclassifying "sub-requirements" to "parts".

To view the SAR and provide comments, please navigate to the Planning Resource Adequacy Analysis, Assessment and Documentation webpage and select the Submit Comments link.

Once again, we would like to thank you for your participation in the ReliabilityFirst Regional Standards process. If you have any questions, please contact Anthony Jablonski anthony.jablonski@rfirst.org at 216-503-0693. Thank you and have a great day.

Planning Resource Adequacy Analysis, Assessment and Documentation 30-Day SAR Comment Posting Question

1. Do you agree with the scope of the Planning Resource Adequacy Analysis, Assessment and Documentation SAR? If not, please provide specific suggestions/comments.

NOTE: This is posted for informational purposes only. Please supply all comments via comment form on the ReliabilityFirst Planning Resource Adequacy Analysis, Assessment and Documentation website.

A. Introduction

1. Title: **Planning Resource Adequacy Analysis, Assessment and Documentation**

2. Number: **BAL-502-RFC-02**

3. Purpose:

To establish common criteria, based on "one day in ten year" loss of Load expectation principles, for the analysis, assessment and documentation of Resource Adequacy for Load in the Reliability*First* Corporation (RFC) region

4. Applicability

4.1 Planning Coordinator

5. Effective Date:

5.1 Upon RFC Board approval

B. Requirements

R1 The Planning Coordinator shall perform and document a Resource Adequacy analysis annually. The Resource Adequacy analysis shall *[Violation Risk Factor: Medium]*:

R1.1 Calculate a planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year[1] analyzed (per R1.2) being equal to 0.1. (This is comparable to a "one day in 10 year" criterion).

R1.1.1 The utilization of Direct Control Load Management or curtailment of Interruptible Demand shall not contribute to the loss of Load probability.

R1.1.2 The planning reserve margin developed from R1.1 shall be expressed as a percentage of the median[2] forecast peak Net Internal Demand (planning reserve margin).

R1.2 Be performed or verified separately for each of the following planning years:

[1] The annual period over which the LOLE is measured, and the resulting resource requirements are established (June 1st through the following May 31st).

[2] The median forecast is expected to have a 50% probability of being too high and 50% probability of being too low (50:50).

R1.2.1 Perform an analysis for Year One.

R1.2.2 Perform an analysis or verification at a minimum for one year in the 2 through 5 year period and at a minimum one year in the 6 though 10 year period.

R1.2.2.1 If the analysis is verified, the verification must be supported by current or past studies for the same planning year.

R1.3 Include the following subject matter and documentation of its use:

R1.3.1 Load forecast characteristics:

- Median (50:50) forecast peak Load.
- Load forecast uncertainty (reflects variability in the Load forecast due to weather and regional economic forecasts).
- Load diversity.
- Seasonal Load variations.
- Daily demand modeling assumptions (firm, interruptible).
- Contractual arrangements concerning curtailable/Interruptible Demand.

R1.3.2 Resource characteristics:

- Historic resource performance and any projected changes
- Seasonal resource ratings
- Modeling assumptions of firm capacity purchases from and sales to entities outside the Planning Coordinator area.
- Resource planned outage schedules, deratings, and retirements.
- Modeling assumptions of intermittent and energy limited resource such as wind and cogeneration.
- Criteria for including planned resource additions in the analysis

R1.3.3 Transmission limitations that prevent the delivery of generation reserves

R1.3.3.1 Criteria for including planned Transmission Facility additions in the analysis

R1.3.4 Assistance from other interconnected systems including multi-area assessment considering Transmission limitations into the study area.

R1.4 Consider the following resource availability characteristics and document how and why they were included in the analysis or why they were not included:

- Availability and deliverability of fuel.
- Common mode outages that affect resource availability
- Environmental or regulatory restrictions of resource availability.
- Any other demand (Load) response programs not included in R1.3.1.
- Sensitivity to resource outage rates.
- Impacts of extreme weather/drought conditions that affect unit availability.
- Modeling assumptions for emergency operation procedures used to make reserves available.
- Market resources not committed to serving Load (uncommitted resources) within the Planning Coordinator area.

R1.5 Consider Transmission maintenance outage schedules and document how and why they were included in the Resource Adequacy analysis or why they were not included

R1.6 Document that capacity resources are appropriately accounted for in its Resource Adequacy analysis

R1.7 Document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis

R2 The Planning Coordinator shall annually document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis *[Violation Risk Factor: Lower]*.

R2.1 This documentation shall cover each of the years in Year One through ten.

R2.2 This documentation shall include the planning reserve margin calculated per requirement R1.1 for each of the three years in the analysis.

R2.3 The documentation as specified per requirement R2.1 and R2.2 shall be publicly posted no later than 30 calendar days prior to the beginning of Year One.

C. Measures

M1 Each Planning Coordinator shall possess the documentation that a valid Resource Adequacy analysis was performed or verified in accordance with R1

M2 Each Planning Coordinator shall possess the documentation of its projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis on an annual basis in accordance with R2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor - Reliability*First* Corporation

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year

1.3. Data Retention

The Planning Coordinator shall retain information from the most current and prior two years.

The Compliance Monitor shall retain any audit data for five years.

2. Violation Severity Levels

Req. Number	VIOLATION SEVERITY LEVEL			
	LOWER	MODERATE	HIGH	SEVERE
R1	The Planning Coordinator Resource Adequacy analysis failed to consider 1 or 2 of the Resource availability characteristics subcomponents under R1.4 and documentation of how and why they were included in the analysis or why they	The Planning Coordinator Resource Adequacy analysis failed to express the planning reserve margin developed from R1.1 as a percentage of the net Median forecast peak Load per R1.1.2 **OR**	The Planning Coordinator Resource Adequacy analysis failed to be performed or verified separately for individual years of Year One through Year Ten per R1.2 **OR**	The Planning Coordinator failed to perform and document a Resource Adequacy analysis annually per R1. **OR** The Planning Coordinator Resource

	were not included **OR** The Planning Coordinator Resource Adequacy analysis failed to consider Transmission maintenance outage schedules and document how and why they were included in the analysis or why they were not included per R1.5	The Planning Coordinator Resource Adequacy analysis failed to include 1 of the Load forecast Characteristics subcomponents under R1.3.1 and documentation of its use **OR** The Planning Coordinator Resource Adequacy analysis failed to include 1 of the Resource Characteristics subcomponents under R1.3.2 and documentation of its use **Or** The Planning Coordinator Resource Adequacy analysis failed to document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis per R1.7	The Planning Coordinator failed to perform an analysis or verification for one year in the 2 through 5 year period or one year in the 6 though 10 year period or both per R1.2.2 **OR** The Planning Coordinator Resource Adequacy analysis failed to include 2 or more of the Load forecast Characteristics subcomponents under R1.3.1 and documentation of their use **OR** The Planning Coordinator Resource Adequacy analysis failed to include 2 or more of the Resource Characteristics subcomponents under R1.3.2 and documentation of their use **OR** The Planning Coordinator Resource Adequacy analysis failed to include Transmission limitations and documentation of its use	Adequacy analysis failed to calculate a Planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year analyzed for each planning period being equal to 0.1 per R1.1 **OR** The Planning Coordinator failed to perform an analysis for Year One per R1.2.1

			per R1.3.3 **OR** The Planning Coordinator Resource Adequacy analysis failed to include assistance from other interconnected systems and documentation of its use per R1.3.4 **OR** The Planning Coordinator Resource Adequacy analysis failed to consider 3 or more Resource availability characteristics subcomponents under R1.4 and documentation of how and why they were included in the analysis or why they were not included **OR** The Planning Coordinator Resource Adequacy analysis failed to document that capacity resources are appropriately accounted for in its Resource Adequacy analysis per R1.6	
R2	The Planning Coordinator failed to publicly post the documents as specified	The Planning Coordinator failed to document the projected Load and resource	The Planning Coordinator failed to document the projected Load and resource	The Planning Coordinator failed to document the projected Load and resource

	per requirement R2.1 and R2.2 later than 30 calendar days prior to the beginning of Year One per R2.3	capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for one of the years in the 2 through 10 year period per R2.1. **OR** The Planning Coordinator failed to document the Planning Reserve margin calculated per requirement R1.1 for each of the three years in the analysis per R2.2.	capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for year 1 of the 10 year period per R2.1. **OR** The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for two or more of the years in the 2 through 10 year period per R2.1.	capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis per R2.

Definitions:

Resource Adequacy - the ability of supply-side and demand-side resources to meet the aggregate electrical demand (including losses).

Net Internal Demand - Total of all end-use customer demand and electric system losses within specified metered boundaries, less Direct Control Load Management and Interruptible Demand.

Peak Period - A period consisting of two (2) or more calendar months but less than seven (7) calendar months, which includes the period during which the responsible entity's annual peak demand is expected to occur

Year One - The planning year that begins with the upcoming annual Peak Period.

The following definitions were extracted from the February 12th, 2008 NERC Glossary of Terms:

Direct Control Load Management – Demand-Side Management that is under the direct control of the system operator. DCLM may control the electric supply to individual appliances or equipment on customer premises. DCLM as defined here does not include Interruptible Demand.

Facility - 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.)

Interruptible Demand - Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment.

Load - An end-use device or customer that receives power from the electric system.

Transmission - An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.

Version History

Version	Date	Action	Change Tracking
BAL-502-RFC-02 1st Draft	06/24/08 Through 07/23/08	Posted for 1st Comment Period	
BAL-502-RFC-02 2nd Draft	08/18/08 Through 09/16/08	Posted for 2nd Comment Period	
BAL-502-RFC-02 3rd Draft	10/16/08 Through 10/30/08	Posted for 15-Day Category Ballot	
BAL-502-RFC-02 3rd Draft	12/04/08	Reliability*First* Board Approved	
BAL-502-RFC-02	06/08/09	"Planning Reserve" changed to "planning reserve" in R2.2.	Errata
BAL-502-RFC-02	08/05/09	Approved by NERC Board of Trustees	
BAL-502-RFC-02	03/17/11	Order issued by FERC approving BAL-502-RFC-02 (approval effective 5/23/11)	

ReliabilityFirst Planning Resource Adequacy Analysis, Assessment and Documentation (BAL-502-RFC-03) – Standards Authorization Request Comment Period - 04/01/16 – 05/10/16

Question	Do you agree with the scope of the Planning Resource Adequacy Analysis, Assessment, and Documentation Standard SAR? If not, please provide specific suggestions or comments.

Consideration of Comments	All commenters agreed with the scope of the BAL-502-RFC-03 Standards Authorization Request.

Answers	Frequency
Yes	3
No	0

Commenter	Company	Answer	Comment
Jeffery Beattie	Consumers Energy	Yes	
Greg Milosek	ITC Holdings Corp.	Yes	ITC, on behalf of ITC Transmission, METC and Michigan Electric Coordinated Systems, is not registered as a Planning Coordinator which applies to BAL-502-RFC, but would like to state that BAL-502-RFC should be reaffirmed and will defer the final decision to MISO who is ITC's Planning Coordinator.
Chris Scanlon	Exelon	Yes	Exelon believes that the Standard is appropriate as is, with the limited exception of addressing the two directives that FERC noted in its Order 747 for initial approval

Standard Authorization Request

The SC shall be responsible for implementing and maintaining this form as needed to support the information requirements of the standards development process in this Procedure. Changes to this form are considered minor, and therefore subject to only the approval of the SC.

ReliabilityFirst Standard Authorization Request Form

ReliabilityFirst will complete
ID - BAL-503-RFC-03
Authorized for Posting - 03/31/16
Authorized for Development – 04/12/16

Title of Proposed Standard: Planning Resource Adequacy Analysis, Assessment and Documentation
Request Date: 03/31/16

SAR Originator Information

Name: Anthony Jablonski	**SAR Type** (Check box for one of these selections.)	
Company: ReliabilityFirst	☐	New Standard
Telephone: 216-503-0693	☒	Revision to Existing Standard
Fax:	☐	Withdrawal of Existing Standard
E-mail: Anthony.Jablonski@rfist.org	☐	Urgent Action

Purpose (Provide one or two sentences.)
The purpose of this SAR is to initiate actions to revise the existing ReliabilityFirst Planning Resource Adequacy Analysis, Assessment and Documentation (BAL-502-RFC-02) Standard to address two FERC Directives as noted in FERC Order No 747 (FERC Order initially approving the Standard). Miscellaneous non-substantive format changes such as, but not limited to, reclassifying "sub-requirements" to "parts" will be considered as well.

Industry Need (Provide one or two sentences.)
The ReliabilityFirst Planning Resource Adequacy Analysis, Assessment and Documentation (BAL-502-RFC-02) Standard was approved as a Regional Reliability Standard by the Commission in Order No 747 on March 17, 2011 and became enforceable on May 23, 2011. The BAL-502-RFC-02 Standard establishes requirements for Planning Authorities/Coordinators in the

ReliabilityFirst region regarding resource adequacy assessment, which subject matter is not currently addressed in NERC's continent-wide Reliability Standards. The Commission also approves four regional reliability definitions related to the approved regional Reliability Standard and the violation risk factors and violation severity levels assigned to the BAL-502-RFC-02 Requirements.

The BAL-502-RFC-02 Standard contains the following two main requirements. Requirement R1 requires each Planning Coordinator in the ReliabilityFirst footprint to perform and document an annual resource adequacy analysis. The sub-requirements of Requirement R1 set forth the criteria to be used for the resource adequacy analysis. Requirement R2 requires each Planning Coordinator to annually document the projected load and resource capability for each area and transmission constrained sub-area identified in the analysis. The sub-requirements of Requirement R2 set forth the specific documentation requirements.

At the time of approval, the Commission directed ReliabilityFirst, at the time it conducts its scheduled five year review, to (1) add time horizons to the two main requirements, and (2) consider modifying the regional Reliability Standard to include a requirement that the planning coordinators identify any gap between the needed amount of planning reserves defined in Requirement R1.1 and the planning reserves determined from the resource adequacy analysis.

ReliabilityFirst conducted a five year review comment posting period (February 29, 2016 through March 9, 2016) in which six individuals responded. All six individual provided responses indicating that they believe the BAL-502-RFC-02 should be reaffirmed (which includes a process to respond to the FERC directives).

Brief Description (A few sentences or a paragraph.)
The Standard Drafting Team (SDT) will review the two main requirements and shall add Time Horizons to each of the Requirements.

The SDT will consider modifying the BAL-502-RFC-02 Standard to include a requirement that the Planning Coordinators identify any gap between the needed amount of planning reserves defined in Requirement R1.1 and the planning reserves determined from the resource adequacy analysis.

The SDT will also consider miscellaneous non-substantive formatting changes such as, but not limited to, reclassifying "sub-requirements" to "parts".

Reliability Functions

The Standard will Apply to the Following Functions (Check box for each one that applies.)

☐	Reliability Authority	Ensures the reliability of the bulk transmission system within its Reliability Authority area. This is the highest reliability authority.

☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within its metered boundary and supports system frequency in real time
☐	Generator Owner	Owns and maintains generating units
☐	Interchange Authority	Authorizes valid and balanced Interchange Schedules
☒	Planning Authority/Planning Coordinator	Plans the BPS
☐	Resource Planner	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
☐	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
☐	Transmission Service Provider	Provides transmission services to qualified market participants under applicable transmission service agreements
☐	Transmission Owner	Owns transmission facilities
☐	Transmission Operator	Operates and maintains the transmission facilities, and executes switching orders
☐	Distribution Provider	Provides and operates the “wires” between the transmission system and the customer
☐	Generator Operator	Operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services
☐	Purchasing-Selling Entity	The function of purchasing or selling energy, capacity and all necessary Interconnected Operations Services as required
☐	Load-Serving Entity	Secures energy and transmission (and related generation services) to serve the end user
☐	Market Operator	Integrates energy, capacity, balancing, and transmission resources to achieve an economic, reliability-constrained dispatch of resources. The dispatch may be either cost-based or bid-based
☐	Regional Reliability Organizations	An entity that ensures that a defined area of the BPS is reliable, adequate and secure. A member of the North American Electric Reliability Council. The Regional

		Reliability Organization can serve as the Compliance Monitor

NOTE: The SDT may find it necessary to modify the initial reliability function responsibility assignment as a result of the standards development and comments received.

Reliability Principles

Applicable Reliability Principles (Check box for all that apply.)	
☒	1. Interconnected BPS 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 BPS 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 BPS 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 BPS 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 BPS.
☐	6. Personnel responsible for planning and operating interconnected BPS shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected BPS shall be assessed, monitored, and maintained on a wide-area basis.

Market Interface Principles

Does the proposed Standard comply with all of the following Market Interface Principles?	
Recognizing that reliability is an essential requirement of a robust North American economy:	
☒yes or ☐no	1. A reliability standard shall not give any market participant an unfair competitive advantage.
☒yes or ☐no	2. A reliability standard shall neither mandate nor prohibit any specific market structure.

☒yes or ☐no	3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.
☒yes or ☐no	4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.

Detailed Description *(*Provide enough detail so that an independent entity familiar with the industry could draft a Standard based on this description.*)*

The SDT will review the two main requirements and shall add Time Horizons to each of the Requirements. The SDT shall review the five Time Horizons listed below and determine which Time Horizon is appropriate for each Requirement:

1. Long-term Planning – a planning horizon of one year or longer.
2. Operations Planning – operating and resource plans from day-ahead up to and including seasonal.
3. Same-day Operations – routine actions required within the timeframe of a day, but not real-time.
4. Real-time Operations – actions required within one hour or less to preserve the reliability of the bulk electric system.
5. Operations Assessment – follow-up evaluations and reporting of real-time operations.

The STD will consider modifying the BAL-502-RFC-02 Standard to include a requirement that the planning coordinators identify any gap between the needed amount of planning reserves defined in Requirement R1.1 and the planning reserves determined from the resource adequacy analysis. This new requirement will be a documentation requirement only and will not require entities to install additional generation or transmission capacity.

- If the SDT decides to not include a new requirement after their consideration, the SDT shall develop a technical justification as to why a new requirement was not included.
- If the SDT decides to include a new requirement after their consideration, the Standards Drafting Team shall also develop associated Measures, Violation Risk Factors, Violation Severity Levels and Time Horizons.

The SDT will also review the Standard and consider miscellaneous non-substantive formatting changes such as, but not limited to, reclassifying “sub-requirements” to “parts”.

Related Standards (NERC and Regional)

Standard No.	Explanation
BAL-502-RFC-02	This Standard was approved by the FERC on March 23, 2011

Related SARs

SAR ID	Explanation

Implementation Plan

Description *(Provide plans for the implementation of the proposed standard, including any known systems or training requirements. Include the reliability risk(s) associated with the violation that the standard will mitigate, and the costs associated with implementation.)*
Proposed Implementation days after Board adoption or **on (date):**

Assignments

	Assignment
Team Members	
ReliabilityFirst *Staff*	

Planning Resource Adequacy Analysis, Assessment and Documentation Standard Drafting Team Nomination Form

Please return this form to anthony.jablonski@rfirst.org by June 6, 2016. For questions, please contact Anthony Jablonski at 216-503-0693.

Please note this drafting team will probably meet initially in the June, 2016 timeframe to review the Planning Resource Adequacy Analysis, Assessment and Documentation SAR posted on the ReliabilityFirst website. The detailed meeting schedule has not been determined as of yet. It is anticipated the team will conduct a number of conference calls as part of this effort. The purpose of this effort is to revise the existing ReliabilityFirst Planning Resource Adequacy Analysis, Assessment and Documentation (BAL-502-RFC-02) Standard to address two FERC Directives as noted in FERC Order No 747 (FERC Order initially approving the Standard). Miscellaneous non-substantive format changes such as, but not limited to, reclassifying "sub-requirements" to "parts" will be considered as well. **All candidates should be prepared to participate actively at these meetings.**

Proposed Regional Reliability Standard: Planning Resource Adequacy Analysis, Assessment and Documentation

Name: Organization: Address: Office Telephone: Mobile Telephone: Fax: Email:
Please briefly describe your experience and qualifications to serve on the Standard Drafting Team. Previous experience working on or applying standards/criteria and/or SARs is very beneficial, but not a requirement.

NERC Reliability Region(s) your	**My company can be categorized by one or more of the following. (check**

company resides in (check all that apply):	**all that apply):**	
☐ ERCOT ☐ FRCC ☐ RF ☐ MRO ☐ NPCC ☐ SERC ☐ SPP ☐ WECC ☐ Not Applicable	☐	1 - Transmission Owners
	☐	2 - RTOs, ISOs, Regional Reliability Councils
	☐	3 - Small Load-serving Entities (Region of 10,000 GWh or less)
	☐	4 - Medium Load-serving Entities (Region between 10,000 GWh and 50,000 GWh)
	☐	5 - Large Load-serving Entities (Region of 50,000 GWh or greater)
	☐	6 - Transmission-dependent Utilities
	☐	7 - Electric Generators
	☐	8 - Electricity Brokers, Aggregators, and Marketers
	☐	9 - Large Electricity End Users
	☐	10 - Small Electricity End Users
	☐	11 - Federal, State, and Provincial Regulatory or other Government Entities

Which of the following Function(s) do you have expertise or responsibilities:

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

Planning Resource Adequacy Analysis, Assessment and Documentation (PRAA)
Standard Drafting Team Roster (06/15/16)

Contact	Company	Email	Phone
Joe O'Brien	NIPSCO	jnobrien@nisource.com	219-853-5470
Jeffery W. Beattie	Consumers Energy	jwbeattie@cmsenergy.com	517-788-7220
Tom Falin	PJM	thomas.falin@pjm.com	610-666-4683
Jordan Cole	MISO	jcole@misoenergy.org	651-632-8573
Anthony Jablonski	ReliabilityFirst Staff	anthony.jablonski@rfirst.org	216-503-0693

A. Introduction

1. Title: **Planning Resource Adequacy Analysis, Assessment and Documentation**

2. Number: **BAL-502-RF-03**

3. Purpose: To establish common criteria, based on "one day in ten year" loss of Load expectation principles, for the analysis, assessment and documentation of Resource Adequacy for Load in the ReliabilityFirst Corporation (RF) region

4. Applicability

4.1 Functional Entities

4.1.1 Planning Coordinator

5. Effective Date:

5.1 BAL-502-RF-03 shall become effective on the first day of the first calendar quarter that is after the date that this standard is approved by applicable regulatory authorities or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect.

B. Requirements and Measures

R1 The Planning Coordinator shall perform and document a Resource Adequacy analysis annually. The Resource Adequacy analysis shall *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*:

1.1 Calculate a planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year[1] analyzed (per R1.2) being equal to 0.1. (This is comparable to a "one day in 10 year" criterion).

1.1.1 The utilization of Direct Control Load Management or curtailment of Interruptible Demand shall not contribute to the loss of Load probability.

1.1.2 The planning reserve margin developed from R1.1 shall be expressed as a percentage of the median[2] forecast peak Net Internal Demand (planning reserve margin).

1.2 Be performed or verified separately for each of the following planning years:

[1] The annual period over which the LOLE is measured, and the resulting resource requirements are established (June 1st through the following May 31st).

[2] The median forecast is expected to have a 50% probability of being too high and 50% probability of being too low (50:50).

1.2.1 Perform an analysis for Year One.

1.2.2 Perform an analysis or verification at a minimum for one year in the 2 through 5 year period and at a minimum one year in the 6 though 10 year period.

1.2.2.1 If the analysis is verified, the verification must be supported by current or past studies for the same planning year.

1.3 Include the following subject matter and documentation of its use:

1.3.1 Load forecast characteristics:

1.3.1.1 Median (50:50) forecast peak Load.

1.3.1.2 Load forecast uncertainty (reflects variability in the Load forecast due to weather and regional economic forecasts).

1.3.1.3 Load diversity.

1.3.1.4 Seasonal Load variations.

1.3.1.5 Daily demand modeling assumptions (firm, interruptible).

1.3.1.6 Contractual arrangements concerning curtailable/Interruptible Demand.

1.3.2 Resource characteristics:

1.3.2.1 Historic resource performance and any projected changes

1.3.2.2 Seasonal resource ratings

1.3.2.3 Modeling assumptions of firm capacity purchases from and sales to entities outside the Planning Coordinator area.

1.3.2.4 Resource planned outage schedules, deratings, and retirements.

1.3.2.5 Modeling assumptions of intermittent and energy limited resource such as wind and cogeneration.

1.3.2.6 Criteria for including planned resource additions in the analysis

1.3.3 Transmission limitations that prevent the delivery of generation reserves

1.3.3.1 Criteria for including planned Transmission Facility additions in the analysis

1.3.4 Assistance from other interconnected systems including multi-area assessment considering Transmission limitations into the study area.

1.4 Consider the following resource availability characteristics and document how and why they were included in the analysis or why they were not included:

1.4.1 Availability and deliverability of fuel.

1.4.2 Common mode outages that affect resource availability

1.4.3 Environmental or regulatory restrictions of resource availability.

1.4.4 Any other demand (Load) response programs not included in R1.3.1.

1.4.5 Sensitivity to resource outage rates.

1.4.6 Impacts of extreme weather/drought conditions that affect unit availability.

1.4.7 Modeling assumptions for emergency operation procedures used to make reserves available.

1.4.8 Market resources not committed to serving Load (uncommitted resources) within the Planning Coordinator area.

1.5 Consider Transmission maintenance outage schedules and document how and why they were included in the Resource Adequacy analysis or why they were not included

1.6 Document that capacity resources are appropriately accounted for in its Resource Adequacy analysis

1.7 Document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis

M1 Each Planning Coordinator shall possess the documentation that a valid Resource Adequacy analysis was performed or verified in accordance with R1

R2 The Planning Coordinator shall annually document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*.

2.1 This documentation shall cover each of the years in Year One through ten.

2.2 This documentation shall include the Planning Reserve margin calculated per requirement R1.1 for each of the three years in the analysis.

2.3 The documentation as specified per requirement R2.1 and R2.2 shall be publicly posted no later than 30 calendar days prior to the beginning of Year One.

M2 Each Planning Coordinator shall possess the documentation of its projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis on an annual basis in accordance with R2.

R3 The Planning Coordinator shall identify any gaps between the needed amount of planning reserves defined in Requirement R1, Part 1.1 and the projected planning reserves documented in Requirement R2 *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*.

M3 Each Planning Coordinator shall possess the documentation identifying any gaps between the needed amounts of planning reserves and projected planning reserves in accordance with R3.

C. Compliance

5. Compliance Monitoring Process

5.1. Compliance Monitoring Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

5.2. Evidence Retention

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

The Applicable Entity shall keep data or evidence to show compliance with Requirements R1 through R3, and Measures M1 through M3 from the most current and prior two years.

If an Applicable Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

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

5.3. Compliance Monitoring and Assessment Processes

Compliance Audit
Self-Certification
Spot Checking
Compliance Investigation
Self-Reporting
Complaint

5.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	VIOLATION SEVERITY LEVEL			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Medium	The Planning Coordinator Resource Adequacy analysis failed to consider 1 or 2 of the Resource availability characteristics subcomponents under Requirement R1, Part 1.4 and documentation of how and why they were included in the analysis or why they were not included **OR** The Planning Coordinator Resource Adequacy analysis failed to consider Transmission maintenance outage schedules and document how and why they were included in the analysis or why they were not included per Requirement R1, Part 1.5	The Planning Coordinator Resource Adequacy analysis failed to express the planning reserve margin developed from Requirement R1, Part 1.1 as a percentage of the net Median forecast peak Load per Requirement R1, Part 1.1.2 **OR** The Planning Coordinator Resource Adequacy analysis failed to include 1 of the Load forecast Characteristics subcomponents under Requirement R1, Part 1.3.1 and documentation of its use **OR**	The Planning Coordinator Resource Adequacy analysis failed to be performed or verified separately for individual years of Year One through Year Ten per Requirement R1, Part 1.2 **OR** The Planning Coordinator failed to perform an analysis or verification for one year in the 2 through 5 year period or one year in the 6 though 10 year period or both per Requirement R1, Part 1.2.2 **OR** The Planning Coordinator Resource Adequacy analysis failed to include 2 or	The Planning Coordinator failed to perform and document a Resource Adequacy analysis annually per R1. **OR** The Planning Coordinator Resource Adequacy analysis failed to calculate a Planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year analyzed for each planning period being equal to 0.1 per Requirement R1, Part 1.1 **OR**

				The Planning Coordinator Resource Adequacy analysis failed to include 1 of the Resource Characteristics subcomponents under Requirement R1, Part 1.3.2 and documentation of its use **Or** The Planning Coordinator Resource Adequacy analysis failed to document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis per Requirement R1, Part 1.7	more of the Load forecast Characteristics subcomponents under Requirement R1, Part 1.3.1 and documentation of their use **OR** The Planning Coordinator Resource Adequacy analysis failed to include 2 or more of the Resource Characteristics subcomponents under Requirement R1, Part 1.3.2 and documentation of their use **OR** The Planning Coordinator Resource Adequacy analysis failed to include Transmission limitations and documentation of its use	The Planning Coordinator failed to perform an analysis for Year One per Requirement R1, Part 1.2.1

					per Requirement R1, Part 1.3.3 **OR** The Planning Coordinator Resource Adequacy analysis failed to include assistance from other interconnected systems and documentation of its use per Requirement R1, Part 1.3.4 **OR** The Planning Coordinator Resource Adequacy analysis failed to consider 3 or more Resource availability characteristics subcomponents under Requirement R1, Part 1.4 and documentation of how and why they were included in the analysis or why they were not included	

					OR The Planning Coordinator Resource Adequacy analysis failed to document that capacity resources are appropriately accounted for in its Resource Adequacy analysis per Requirement R1, Part 1.6	
R2	Long-term Planning	Lower	The Planning Coordinator failed to publicly post the documents as specified per requirement Requirement R2, Part 2.1 and Requirement R2, Part 2.2 later than 30 calendar days prior to the beginning of Year One per Requirement R2, Part 2.3	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for one of the years in the 2 through 10 year period per Requirement R2, Part 2.1. **OR** The Planning Coordinator failed to document the Planning	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for year 1 of the 10 year period per Requirement R2, Part 2.1. **OR** The Planning Coordinator failed to document the projected Load and resource	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis per Requirement R2, Part 2.

				Reserve margin calculated per requirement R1.1 for each of the three years in the analysis per Requirement R2, Part 2.2.	capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for two or more of the years in the 2 through 10 year period per Requirement R2, Part 2.1.	
R3	Long-term Planning	Lower	None	None	None	The Planning Coordinator failed to identify any gaps between the needed amount of planning reserves and the projected planning reserves, per R3

D. Regional Variances

None

E. Interpretations

None

F. Associated Documents

None

Version History

Version	Date	Action	Change Tracking
BAL-502-RFC-02	12/04/08	ReliabilityFirst Board Approved	
BAL-502-RFC-02	08/05/09	NERC BoT Approved	
BAL-502-RFC-02	03/17/11	FERC Approved	

Standard BAL-502-RF-03

A. Introduction

1. Title: **Planning Resource Adequacy Analysis, Assessment and Documentation**

2. Number: **BAL-502-RF-03**

3. Purpose: To establish common criteria, based on "one day in ten year" loss of Load expectation principles, for the analysis, assessment and documentation of Resource Adequacy for Load in the ReliabilityFirst Corporation (RF) region

4. Applicability

4.1 Functional Entities

4.1.1 Planning Coordinator

5. Effective Date:

5.1 BAL-502-RF-03 shall become effective on the first day of the first calendar quarter that is after the date that this standard is approved by applicable regulatory authorities or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect.

B. Requirements and Measures

R1 The Planning Coordinator shall perform and document a Resource Adequacy analysis annually. The Resource Adequacy analysis shall *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*:

1.1 Calculate a planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year[1] analyzed (per R1.2) being equal to 0.1. (This is comparable to a "one day in 10 year" criterion).

1.1.1 The utilization of Direct Control Load Management or curtailment of Interruptible Demand shall not contribute to the loss of Load probability.

1.1.2 The planning reserve margin developed from R1.1 shall be expressed as a percentage of the median[2] forecast peak Net Internal Demand (planning reserve margin).

1.2 Be performed or verified separately for each of the following planning years:

[1] The annual period over which the LOLE is measured, and the resulting resource requirements are established (June 1st through the following May 31st).

[2] The median forecast is expected to have a 50% probability of being too high and 50% probability of being too low (50:50).

Deleted: C
Deleted: 2
Deleted: 12/04/08
Deleted: C
Deleted: 2
Formatted: Indent: Hanging: 0.15", Outline numbered + Level: 1 + Numbering Style: 1, 2, 3, … + Start at: 1 + Alignment: Left + Aligned at: 0" + Tab after: 0.4" + Indent at: 0.4", Tab stops: Not at 0.5"
Deleted: ¶
Formatted: Font: Not Italic
Deleted: C
Deleted: ¶
Deleted: Planning Coordinator
Formatted: Outline numbered + Level: 3 + Numbering Style: 1, 2, 3, … + Start at: 1 + Alignment: Left + Aligned at: 1" + Tab after: 1.5" + Indent at: 1.5"
Deleted: ¶
Deleted: Upon RFC Board approval ¶
Formatted: Font: Italic, Font color: Auto
Deleted: R
Deleted: R
Deleted: R
Deleted: R
Deleted: December 4th
Deleted: 08

1.2.1 Perform an analysis for Year One.

1.2.2 Perform an analysis or verification at a minimum for one year in the 2 through 5 year period and at a minimum one year in the 6 though 10 year period.

1.2.2.1 If the analysis is verified, the verification must be supported by current or past studies for the same planning year.

1.3 Include the following subject matter and documentation of its use:

1.3.1 Load forecast characteristics:

1.3.1.1 Median (50:50) forecast peak Load.

1.3.1.2 Load forecast uncertainty (reflects variability in the Load forecast due to weather and regional economic forecasts).

1.3.1.3 Load diversity.

1.3.1.4 Seasonal Load variations.

1.3.1.5 Daily demand modeling assumptions (firm, interruptible).

1.3.1.6 Contractual arrangements concerning curtailable/Interruptible Demand.

1.3.2 Resource characteristics:

1.3.2.1 Historic resource performance and any projected changes

1.3.2.2 Seasonal resource ratings

1.3.2.3 Modeling assumptions of firm capacity purchases from and sales to entities outside the Planning Coordinator area.

1.3.2.4 Resource planned outage schedules, deratings, and retirements.

1.3.2.5 Modeling assumptions of intermittent and energy limited resource such as wind and cogeneration.

1.3.2.6 Criteria for including planned resource additions in the analysis

1.3.3 Transmission limitations that prevent the delivery of generation reserves

1.3.3.1 Criteria for including planned Transmission Facility additions in the analysis

Deleted: C
Deleted: 2
Deleted: 12/04/08
Deleted: R
Deleted: R
Deleted: R
Deleted: R
Deleted: R
Formatted: Indent: Left: 1.5", No bullets or numbering
Formatted: Indent: Left: 1.5", Hanging: 0.5", No bullets or numbering
Formatted: Indent: Left: 1.5", Hanging: 0.5"
Deleted: R
Formatted: Indent: Left: 1.5", No bullets or numbering
Formatted: Indent: Left: 1.5", Hanging: 0.5"
Formatted: Indent: Left: 1.5", Hanging: 0.5"
Formatted: Indent: Left: 1", First line: 0.5"
Deleted: R
Deleted: R
Deleted: December 4th
Deleted: 08

1.3.4 Assistance from other interconnected systems including multi-area assessment considering Transmission limitations into the study area.

1.4 Consider the following resource availability characteristics and document how and why they were included in the analysis or why they were not included:

1.4.1 Availability and deliverability of fuel.

1.4.2 Common mode outages that affect resource availability

1.4.3 Environmental or regulatory restrictions of resource availability.

1.4.4 Any other demand (Load) response programs not included in R1.3.1.

1.4.5 Sensitivity to resource outage rates.

1.4.6 Impacts of extreme weather/drought conditions that affect unit availability.

1.4.7 Modeling assumptions for emergency operation procedures used to make reserves available.

1.4.8 Market resources not committed to serving Load (uncommitted resources) within the Planning Coordinator area.

1.5 Consider Transmission maintenance outage schedules and document how and why they were included in the Resource Adequacy analysis or why they were not included

1.6 Document that capacity resources are appropriately accounted for in its Resource Adequacy analysis

1.7 Document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis

M1 Each Planning Coordinator shall possess the documentation that a valid Resource Adequacy analysis was performed or verified in accordance with R1

R2 The Planning Coordinator shall annually document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis *[Violation Risk Factor: Lower]* *[Time Horizon: Long-term Planning]*.

2.1 This documentation shall cover each of the years in Year One through ten.

2.2 This documentation shall include the Planning Reserve margin calculated per requirement R1.1 for each of the three years in the analysis.

Deleted: C
Deleted: 2
Deleted: 12/04/08
Deleted: R
Deleted: R
Formatted: Indent: Left: 1", No bullets or numbering
Formatted: Indent: Left: 1", Hanging: 0.5"
Deleted: R
Deleted: R
Deleted: R
Formatted: Indent: Left: 0", First line: 0"
Deleted:
Formatted: Indent: Left: 0", First line: 0"
Deleted: R
Deleted: R
Deleted: R
Deleted: December 4th
Deleted: 08

2.3 The documentation as specified per requirement R2.1 and R2.2 shall be publicly posted no later than 30 calendar days prior to the beginning of Year One.

M2 Each Planning Coordinator shall possess the documentation of its projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis on an annual basis in accordance with R2.

R3 The Planning Coordinator shall identify any gaps between the needed amount of planning reserves defined in Requirement R1, Part 1.1 and the projected planning reserves documented in Requirement R2 *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning].*

M3 Each Planning Coordinator shall possess the documentation identifying any gaps between the needed amounts of planning reserves and projected planning reserves in accordance with R3.

C. Compliance

5. Compliance Monitoring Process

5.1. Compliance Monitoring Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

5.2. Evidence Retention

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

The Applicable Entity shall keep data or evidence to show compliance with Requirements R1 through R3, and Measures M1 through M3 from the most current and prior two years.

If an Applicable Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

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

5.3. Compliance Monitoring and Assessment Processes

Compliance Audit
Self-Certification
Spot Checking
Compliance Investigation
Self-Reporting
Complaint

5.4. Additional Compliance Information

None

Deleted: C
Deleted: 2
Deleted: 12/04/08
Deleted: R
Formatted: Font: Not Bold
Deleted: ¶
Measures¶
¶
M1 . Each Planning Coordinator shall possess the documentation that a valid Resource Adequacy analysis was performed or verified in accordance with R1¶
¶
M2 . Each Planning Coordinator shall possess the documentation of its projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis on an annual basis in accordance with R2.¶
¶
Formatted: Indent: Left: 0.25", No bullets or numbering
Deleted: Responsibility
Deleted: Compliance Monitor - ReliabilityFirst Corporation
Formatted: Font: Not Italic
Deleted: <#>Compliance Monitoring Period and Reset Timeframe¶
One calendar year¶
¶
Deleted: <#>Data
Formatted: Font: 11 pt
Deleted:
Formatted: Indent: Left: 0.88"
Deleted: Planning Coordinator
Deleted: retain information
Deleted:
Formatted: Indent: Left: 0.85", No bullets or numbering
Deleted: The Compliance Monitor shall retain any audit data for five years.
Formatted: Font: Bold
Formatted: Outline numbered + Level: 2 + Numbering Style: 1, 2, 3, … + Start at: 1 + Alignment: Left + Aligned at: 0.5" + Tab after: 0.85" + Indent at: 0.85"
Formatted: Indent: Left: 0.85", No bullets or numbering
Formatted: Indent: Left: 0.85"
Formatted: Font: Bold
Formatted: Outline numbered + Level: 2 + Numbering Style: 1, 2, 3, … + Start at: 1 + Alignment: Left + Aligned at: 0.5" + Tab after: 0.85" + Indent at: 0.85"
Formatted: Font: Not Bold
Formatted: Indent: Left: 0.85"
Deleted: December 4th
Deleted: 08

Table of Compliance Elements

R #	Time Horizon	VRF	VIOLATION SEVERITY LEVEL			
			Lower VSL	Moderate VSL	High VSL	
R1	Long-term Planning	Medium	The Planning Coordinator Resource Adequacy analysis failed to consider 1 or 2 of the Resource availability characteristics subcomponents under Requirement R1, Part 1.4 and documentation of how and why they were included in the analysis or why they were not included **OR** The Planning Coordinator Resource Adequacy analysis failed to consider Transmission maintenance outage schedules and document how and why they were included in the analysis or why they were not included per Requirement R1, Part 1.5	The Planning Coordinator Resource Adequacy analysis failed to express the planning reserve margin developed from Requirement R1, Part 1.1 as a percentage of the net Median forecast peak Load per Requirement R1, Part 1.1.2 **OR** The Planning Coordinator Resource Adequacy analysis failed to include 1 of the Load forecast Characteristics subcomponents under Requirement R1, Part 1.3.1 and documentation of its use **OR**	The Planning Coordinator Resource Adequacy analysis failed to be performed or verified separately for individual years of Year One through Year Ten per Requirement R1, Part 1.2 **OR** The Planning Coordinator failed to perform an analysis or verification for one year in the 2 through 5 year period or one year in the 6 though 10 year period or both per Requirement R1, Part 1.2.2 **OR** The Planning Coordinator Resource Adequacy analysis failed to include 2 or	The Pla Coordi perform Resour analysi R1. **OR** The Pla Coordi Adequacy analysis failed to calculate a Planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year analyzed for eac being equal to 0.1 per Requirement R1, Part 1.1 **OR**

Deleted: C
Deleted: 2
Deleted: 12/04/08
Deleted: Violation Severity Levels¶
Formatted: Indent: Left: 0", First line: 0"
Formatted: Width: 14.29", Height: 8.5"
Formatted Table
Deleted: Req. Number
Deleted: LOWER
Deleted: MODERATE
Deleted: HIGH
Deleted: SEVERE
Deleted: ¶
Deleted: R
Deleted: R
Deleted: R
Deleted: R
Deleted: R
Deleted: R
Deleted: R
Deleted: R
Deleted: December 4th
Deleted: 08

				The Planning Coordinator Resource Adequacy analysis failed to include 1 of the Resource Characteristics subcomponents under Requirement R1, Part 1.3.2 and documentation of its use **Or** The Planning Coordinator Resource Adequacy analysis failed to document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis per Requirement R1, Part 1.7	more of the Load forecast Characteristics subcomponents under Requirement R1, Part 1.3.1 and documentation of their use **OR** The Planning Coordinator Resource Adequacy analysis failed to include 2 or more of the Resource Characteristics subcomponents under Requirement R1, Part 1.3.2 and documentation of their use **OR** The Planning Coordinator Resource Adequacy analysis failed to include Transmission limitations and documentation of its use	The Planning Coordinator failed to perform an analysis for Year One per Requirement R1, Part 1.2.1

Deleted: C
Deleted: 2
Deleted: 12/04/08
Deleted: R
Deleted: R
Deleted: R
Deleted: R
Deleted: R
Deleted: December 4th
Deleted: 08

					per Requirement R1, Part 1.3.3 **OR** The Planning Coordinator Resource Adequacy analysis failed to include assistance from other interconnected systems and documentation of its use per Requirement R1, Part 1.3.4 **OR** The Planning Coordinator Resource Adequacy analysis failed to consider 3 or more Resource availability characteristics subcomponents under Requirement R1, Part 1.4 and documentation of how and why they were included in the analysis or why they were not included	

Deleted: C
Deleted: 2
Deleted: 12/04/08
Deleted: R
Deleted: R
Deleted: R
Deleted: December 4th
Deleted: 08

					OR The Planning Coordinator Resource Adequacy analysis failed to document that capacity resources are appropriately accounted for in its Resource Adequacy analysis per Requirement R1, Part 1.6	
R2	Long-term Planning	Lower	The Planning Coordinator failed to publicly post the documents as specified per requirement Requirement R2, Part 2.1 and Requirement R2, Part 2.2 later than 30 calendar days prior to the beginning of Year One per Requirement R2, Part 2.3	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for one of the years in the 2 through 10 year period per Requirement R2, Part 2.1. **OR** The Planning Coordinator failed to document the Planning	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for year 1 of the 10 year period per Requirement R2, Part 2.1. **OR** The Planning Coordinator failed to document the projected Load and resource	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constra identifi Resource Adequacy analysis per Requir

Deleted: C
Deleted: 2
Deleted: 12/04/08
Deleted: R
Deleted: R
Deleted: R
Deleted: R
Deleted: R
Deleted: R
Deleted: December 4th
Deleted: 08

				Reserve margin calculated per requirement R1.1 for each of the three years in the analysis per Requirement R2, Part 2.2.	capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for two or more of the years in the 2 through 10 year period per Requirement R2, Part 2.1.	
R3	Long-term Planning	Lower	None	None	None	The Planning Coordinator failed to identify any gaps between the needed amount of planning reserves and the projected planning reserves, per R3

Deleted: C
Deleted: 2
Deleted: 12/04/08
Deleted: R
Deleted: R
Deleted: December 4th
Deleted: 08

Deleted: C

Deleted: 2

Deleted: 12/04/08

D. Regional Variances

None

Deleted: None

E. Interpretations

Deleted: Interpretations

None

Deleted: None

F. Associated Documents

Deleted: Associated Documents

None

Deleted: None

Deleted: **Definitions:**¶
Resource Adequacy - the ability of supply-side and demand-side resources to meet the aggregate electrical demand (including losses).¶
¶
Net Internal Demand - Total of all end-use customer demand and electric system losses within specified metered boundaries, less Direct Control Load Management and Interruptible Demand.¶
¶
Peak Period - A period consisting of two (2) or more calendar months but less than seven (7) calendar months, which includes the period during which the responsible entity's annual peak demand is expected to occur¶
¶
Year One - The planning year that begins with the upcoming annual Peak Period.¶
¶
The following definitions were extracted from the February 12th, 2008 NERC Glossary of Terms:¶
¶
¶
Direct Control Load Management – Demand-Side Management that is under the direct control of the system operator. DCLM may control the electric supply to individual appliances or equipment on customer premises. DCLM as defined here does not include Interruptible Demand.¶
¶
Facility - 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.)¶
¶
Interruptible Demand - Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment.¶
¶
Load - An end-use device or customer that receives power from the electric system.¶
…

Version History

Version	Date	Action	Change Tracking
BAL-502-RFC-02	12/04/08	ReliabilityFirst Board Approved	
BAL-502-RFC-02	08/05/09	NERC BoT Approved	
BAL-502-RFC-02	03/17/11	FERC Approved	

Deleted: 1st Draft

Deleted: 06/24/08 Through 07/23/08

Deleted: Posted for 1st Comment Period

Deleted: 2nd Draft

Deleted: 08/18/08 Through 09/16/08

Deleted: Posted for 2nd Comment Period

Deleted: 3rd Draft

Deleted: 10/16/08 Through 10/30/08

Deleted: Posted for 15-Day Category Ballot

Deleted: BAL-502-RFC-02 3rd Draft

Deleted: 12/04/08

Deleted: ReliabilityFirst Board Approved

Formatted: Font: Not Italic

Deleted: December 4th

Deleted: 08

Draft Planning Resource Adequacy Analysis, Assessment and Documentation (BAL-502-RF-03) Implementation Plan

Requested Approvals

- None

Requested Retirements

- BAL-502-RFC-02

Prerequisite Approval

- None

Revisions to Defined Terms in the NERC Glossary

- None

Effective Date

- BAL-502-RF-03 shall become effective on the first day of the first calendar quarter that is after the date that this standard is approved by applicable regulatory authorities or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect.

Draft Planning Resource Adequacy Analysis, Assessment and Documentation (BAL-502-RF-03) Perceived Reliability Impact

The Planning Resource Adequacy and Assessment (PRAA) Standard Drafting Team (SDT) believes the additions of Time Horizons and non-substantive changes will have no reliability impact as these are more administrative in nature.

The Planning Resource Adequacy and Assessment (PRAA) Standard Drafting Team (SDT) believes the new Requirement R3 will have a perceived reliability impact of ensuring the Planning Coordinators within the ReliabilityFirst footprint identify any gaps between the needed amount of planning reserves defined in Requirement R1, Part 1.1 and the projected planning reserves determined from the resource adequacy analysis. By identifying these gaps, the Planning Coordinator will document any deficiencies in planning reserves to help ensure that entities within their footprint are aware of potential risks regarding the capability to balance resources and demand in a planning timeframe.

Draft Planning Resource Adequacy Analysis, Assessment and Documentation (BAL-502-RF-03) Assessment of Impact on Neighboring Regions

The Planning Resource Adequacy and Assessment (PRAA) Standard Drafting Team (SDT) believes there is no impact on neighboring regions as a result of the recommended non-substantive changes, addition of "Time Horizons" and addition of a new Requirement R3. Requirement R3, requires the Planning Coordinator to identify any gaps between the needed amount of planning reserves defined in Requirement R1, Part 1.1 and the projected planning reserves documented in Requirement R2. Historically, the two Planning Coordinators within the ReliabilityFirst region have already been identifying this gap via a number of public reports, thus this change will result in no change for neighboring Regions which also include these two Planning coordinators.

Since there is no impact on neighboring regions, there was no need for the PRAA SDT to solicit appropriate input from the neighboring regions.

Substantive Changes within Draft BAL-502-RF-03 standard

1. Included a new Requirement R3 to address the Directive in FERC Order No 747 to include a requirement that the Planning Coordinators identify any gap between the needed amount of planning reserves defined in Requirement R1.1 and the planning reserves determined from the resource adequacy analysis.
2. Included a new Measure M3 as a result of the newly added Requirement R3.
3. Included new Violation Severity Levels as a result of the newly added Requirement R3.
4. Included time horizons to the Requirement R1, R2 and the newly included R3 to address the Directive in FERC Order No 747 to add time horizons to the two main requirements.

Non-Substantive Changes within Draft BAL-502-RF-03 standard

1. Changed name from BAL-502-RFC-02 to BAL-502-RF-03
2. Updated the formatting of Section A (Introduction)
3. Updated Effective date section for the Standards to become effective on the first day of the first calendar quarter that is after the date that this standard is approved by applicable regulatory authorities.
4. Added the term “and Measures” to section B heading
5. Placed Measures immediately following the associate Requirement
6. Removed the “R” from all sub-requirements making them sub-parts
7. Updated section C (Compliance) to be consistent with NERC Standard Boilerplate language
8. Renamed “Violation Severity Levels” section to “Table of Compliance Elements”
9. Updated “Table of Compliance Elements” to include “Time Horizons” and “VRFs”
10. Added sections D (Regional Variances), E (Interpretations) and F (Associated Documents) to end of Standard.
11. Changed bulleted items in R1.3.1, R1.3.2 and R1.4 to sub-parts. Bullets in Standards are meant to be “OR” statements. The intent of these bulleted items was not to be “OR” statements, rather be “AND” statements.
12. Updated Version History to include RF Board, NERC BoT and FERC approval dates.

Draft Planning Resource Adequacy Analysis, Assessment and Documentation (BAL-502-RF-03) 1st 30-Day Comment Posting Questions

1. [OPTION 1) - Do you agree that the modifications made to the BAL-502-RF-03 draft standard are consistent with the scope of the BAL-502-RF-03 Standard Authorization Request (SAR)? If not, please provide specific comments why you do not agree that the BAL-502-RF-03 draft standard is consistent with the scope of the BAL-502-RF-03 SAR.

2. [OPTION 2a] Do you agree with the newly added Time Horizons for each Requirement? If not, please provide specific comments why you do not agree the newly designated Time Horizons.

3. [OPTION 2b] Do you agree with the non-substantive changes made throughout the standard? If not, please provide specific comments why you do not agree with the non-substantive changes made throughout the standard.

4. [OPTION 2c] Do you agree that the newly added Requirement R3 is responsive to the Directive noted in FERC Order No 747, to include a requirement requiring the Planning Coordinator to identify any gap between the needed amount of planning reserves defined in Requirement R1.1 and the planning reserves determined from the resource adequacy analysis? If not, please provide specific comments why you do not agree the newly added Requirement R3 is responsive to the FERC Directive

5. Do you agree with the newly included Measure M3? If not, please provide specific comments why you do not agree with the newly included Measure M3.

6. Do you agree with the newly included Violation Severity Levels (VSLs) for Requirement R3? If not, please provide specific comments why you do not agree with the newly included VSLs for Requirement R3.

7. Do you agree with the BAL-502-RF-03 Implementation Plan? If not, please provide specific comments why you do not agree with the Implementation Plan.

NOTE: This is posted for informational purposes only. Please supply all comments via the ReliabilityFirst site located at: 123

ReliabilityFirst Planning Resource Adequacy Analysis, Assessment and Documentation (BAL-502-RF-03) 30-Day Comment Period - 09/12/2016 - 10/11/2016

Question 1	Do you agree with the newly added Time Horizons for each Requirement? If not, please provide specific comments on why you do not agree with the newly designated Time Horizons.

Consideration of Comments	One commenter agreed with the newly designated Time Horizons. One commenter indicated that the BAL-502-RF-03 Standard should be retired. The SDT disagreed as it is outside the scope of the SAR to determine if the BAL-502-RF-03 Standards should be retired. No changes made.

Answers	Frequency
Yes	1
No	1
Abstain	0

Commenter	Answer	Comment	Response
Scott Cunningham (OVEC)	No	The standard should be retired as it does not address a reliability need. There are adequate market incentives to fill the planning reserve requirement.	It is outside of the Standards Authorization Request (SAR) to determine whether the standards should be retired. During the SAR comment period (conducted 04/01/16 – 05/10/16), all individuals whom provided comments agreed with the scope of the SAR. Furthermore during the “five year review” comment period (conducted 02/29/16 – 03/09/16), all individuals who provided comments indicated the Standard should be re-affirmed. Also, the BAL-502-RF-03 standards does not require the Planning Coordinator to “fill the planning reserve requirement”, rather it establishes common criteria, based on “one day in ten year” loss of Load expectation principles, for the analysis, assessment

			and documentation of Resource Adequacy for Load in the ReliabilityFirst Corporation region.
Sean Bodkin (Dominion)	Yes		Thank you.

Question 2	Do you agree with the non-substantive changes made throughout the Standard? If not, please provide specific comments on why you do not agree with the non-substantive changes made throughout the Standard.

Consideration of Comments	Both commenters agreed with the non-substantive changes. It was noted, outside of the comment period, that there was two non-substantive formatting in Section C (Compliance). The first issue was the numbering started with a five and it should have started with a one. The second issue was the heading for 1.1 was incorrectly labeled as "Compliance Monitoring Authority" when it should have been labeled as "Compliance Enforcement Authority". Both non-substantive issues have been addressed and reflected in the posted redline version.

Answers	Frequency
Yes	2
No	0
Abstain	0

Commenter	Answer	Comment	Response
Scott Cunningham (OVEC)	Yes		Thank you.
Sean Bodkin (Dominion)	Yes		Thank you.

Question 3	Do you agree that the newly added Requirement R3 is responsive to the Directive noted in FERC Order No 747, to include a requirement requiring the Planning Coordinator to identify any gap between the needed amount of planning reserves defined in Requirement R1.1 and the planning reserves determined from the resource adequacy analysis? If not, please provide specific comments on why you do not agree that the newly added Requirement R3 is responsive to the FERC Directive.

Consideration of Comments	One commenter agreed with the newly added Requirement R3. One commenter indicated that there is no requirement in any standard to address the gap. The SDT agreed as NERC's ability to require the building or acquisition of new generating capacity, is prohibited by section 215(a)(3) of the FPA. No changes made.

Answers	Frequency
Yes	1
No	1
Abstain	0

Commenter	Answer	Comment	Response
Scott Cunningham (OVEC)	No	Even if the PC identifies a gap, there is no requirement in any standard to address the gap. There are market incentives for resource owners to address the planning reserve requirement.	You are correct, if the PC identifies a gap, there is no requirement in any standard to address the gap. NERC's ability to require the building or acquisition of new generating capacity, is prohibited by section 215(a)(3) of the FPA and thus no corresponding requirement is proposed. Furthermore, the addition of the new requirement R3 was a result of a Directive noted in FERC Order No 747.
Sean Bodkin (Dominion)	Yes		Thank you.

Question 4	Do you agree with the newly included Measure M3? If not, please provide specific comments on why you do not agree with the newly included Measure M3.

Consideration of Comments	One commenter agreed with the newly added Measure M3. One commenter indicated that there is no requirement in any standard to address the gap. The SDT agreed as NERC's ability to require the building or acquisition of new generating capacity, is prohibited by section 215(a)(3) of the FPA. No changes made.

Answers	Frequency
Yes	1
No	1
Abstain	0

Commenter	Answer	Comment	Response
Scott Cunningham (OVEC)	No	Similar to the above question, the PC may document load and	You are correct, if the PC identifies a gap, there is no requirement in any

		resources, but there is no requirement in the standards to address any gaps.	standard to address the gap. NERC's ability to require the building or acquisition of new generating capacity, is prohibited by section 215(a)(3) of the FPA and thus no corresponding requirement is proposed. Furthermore, the addition of the new requirement R3 was a result of a Directive noted in FERC Order No 747.
Sean Bodkin (Dominion)	Yes		Thank you.

Question 5	Do you agree with the newly included Violation Severity Levels (VSLs) for Requirement R3? If not, please provide specific comments on why you do not agree with the newly included VSLs for Requirement R3.

Consideration of Comments	One commenter agreed with the newly added VSLs. One commenter indicated these standards must function in a market environment, market incentives should address the requirements. The SDT noted that the BAL-502-RF-03 standards does not require the Planning Coordinator to "fill the planning reserve requirement", rather it establishes common criteria, based on "one day in ten year" loss of Load expectation principles, for the analysis, assessment and documentation of Resource Adequacy for Load in the ReliabilityFirst Corporation region. The SDT also noted NERC's ability to require the building or acquisition of new generating capacity, is prohibited by section 215(a)(3) of the FPA. No changes made.

Answers	Frequency
Yes	1
No	1
Abstain	0

Commenter	Answer	Comment	Response
Scott Cunningham (OVEC)	No	Given that these standards must function in a market environment, market incentives should address the requirements. If they do not, we should not be fostering a market-driven system.	Thank you for your comment. The BAL-502-RF-03 standards does not require the Planning Coordinator to "fill the planning reserve requirement", rather it establishes common criteria,

			based on “one day in ten year” loss of Load expectation principles, for the analysis, assessment and documentation of Resource Adequacy for Load in the ReliabilityFirst Corporation region. NERC’s ability to require the building or acquisition of new generating capacity, is prohibited by section 215(a)(3) of the FPA and thus no corresponding requirement is proposed.
Sean Bodkin (Dominion)	Yes		Thank you.

Question 6	Do you agree with the BAL-502-RF-03 Implementation Plan? If not, please provide specific comments on why you do not agree with the BAL-502-RF-03 Implementation Plan.

Consideration of Comments	One commenter agreed with the Implementation Plan. One commenter reiterated comments submitted for question 1 and 5. No changes made.

Answers	Frequency
Yes	1
No	1
Abstain	0

Commenter	Answer	Comment	Response
Scott Cunningham (OVEC)	No	See responses to questions 1 and 5.	See responses to questions 1 and 5.
Sean Bodkin (Dominion)	Yes		

Draft Planning Resource Adequacy Analysis, Assessment and Documentation (BAL-502-RF-03) Ballot Pool Registration Form

Individuals registered in the ReliabilityFirst Ballot Body are allowed to join the Planning Resource Adequacy Analysis, Assessment and Documentation Ballot Pool beginning September 12, 2016 through the close of business of the seventh day of the 15-Day pre-ballot posting period.

Individuals whom are not currently registered in the ReliabilityFirst Ballot Body must first submit a Ballot Body registration form, and be approved as a Ballot Body member prior to joining the associated Planning Resource Adequacy Analysis, Assessment and Documentation Ballot Pool.

Please complete this Ballot Pool registration form and send it to the Standards Process Manager. Upon review of your registration, you will receive a confirmation email. Confirmation may take up to 24 hours. If you have any questions, please contact Anthony Jablonski anthony.jablonski@rfirst.org at 216-503-0693.

Name:
Company:
Email:
Phone:

A. Introduction

1. Title: **Planning Resource Adequacy Analysis, Assessment and Documentation**

2. Number: **BAL-502-RF-03**

3. Purpose: To establish common criteria, based on "one day in ten year" loss of Load expectation principles, for the analysis, assessment and documentation of Resource Adequacy for Load in the ReliabilityFirst Corporation (RF) region

4. Applicability

4.1 Functional Entities

4.1.1 Planning Coordinator

5. Effective Date:

5.1 BAL-502-RF-03 shall become effective on the first day of the first calendar quarter that is after the date that this standard is approved by applicable regulatory authorities or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect.

B. Requirements and Measures

R1 The Planning Coordinator shall perform and document a Resource Adequacy analysis annually. The Resource Adequacy analysis shall *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*:

1.1 Calculate a planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year[1] analyzed (per R1.2) being equal to 0.1. (This is comparable to a "one day in 10 year" criterion).

1.1.1 The utilization of Direct Control Load Management or curtailment of Interruptible Demand shall not contribute to the loss of Load probability.

1.1.2 The planning reserve margin developed from R1.1 shall be expressed as a percentage of the median[2] forecast peak Net Internal Demand (planning reserve margin).

1.2 Be performed or verified separately for each of the following planning years:

[1] The annual period over which the LOLE is measured, and the resulting resource requirements are established (June 1st through the following May 31st).

[2] The median forecast is expected to have a 50% probability of being too high and 50% probability of being too low (50:50).

1.2.1 Perform an analysis for Year One.

1.2.2 Perform an analysis or verification at a minimum for one year in the 2 through 5 year period and at a minimum one year in the 6 though 10 year period.

1.2.2.1 If the analysis is verified, the verification must be supported by current or past studies for the same planning year.

1.3 Include the following subject matter and documentation of its use:

1.3.1 Load forecast characteristics:

1.3.1.1 Median (50:50) forecast peak Load.

1.3.1.2 Load forecast uncertainty (reflects variability in the Load forecast due to weather and regional economic forecasts).

1.3.1.3 Load diversity.

1.3.1.4 Seasonal Load variations.

1.3.1.5 Daily demand modeling assumptions (firm, interruptible).

1.3.1.6 Contractual arrangements concerning curtailable/Interruptible Demand.

1.3.2 Resource characteristics:

1.3.2.1 Historic resource performance and any projected changes

1.3.2.2 Seasonal resource ratings

1.3.2.3 Modeling assumptions of firm capacity purchases from and sales to entities outside the Planning Coordinator area.

1.3.2.4 Resource planned outage schedules, deratings, and retirements.

1.3.2.5 Modeling assumptions of intermittent and energy limited resource such as wind and cogeneration.

1.3.2.6 Criteria for including planned resource additions in the analysis

1.3.3 Transmission limitations that prevent the delivery of generation reserves

1.3.3.1 Criteria for including planned Transmission Facility additions in the analysis

1.3.4 Assistance from other interconnected systems including multi-area assessment considering Transmission limitations into the study area.

1.4 Consider the following resource availability characteristics and document how and why they were included in the analysis or why they were not included:

1.4.1 Availability and deliverability of fuel.

1.4.2 Common mode outages that affect resource availability

1.4.3 Environmental or regulatory restrictions of resource availability.

1.4.4 Any other demand (Load) response programs not included in R1.3.1.

1.4.5 Sensitivity to resource outage rates.

1.4.6 Impacts of extreme weather/drought conditions that affect unit availability.

1.4.7 Modeling assumptions for emergency operation procedures used to make reserves available.

1.4.8 Market resources not committed to serving Load (uncommitted resources) within the Planning Coordinator area.

1.5 Consider Transmission maintenance outage schedules and document how and why they were included in the Resource Adequacy analysis or why they were not included

1.6 Document that capacity resources are appropriately accounted for in its Resource Adequacy analysis

1.7 Document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis

M1 Each Planning Coordinator shall possess the documentation that a valid Resource Adequacy analysis was performed or verified in accordance with R1

R2 The Planning Coordinator shall annually document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*.

2.1 This documentation shall cover each of the years in Year One through ten.

2.2 This documentation shall include the Planning Reserve margin calculated per requirement R1.1 for each of the three years in the analysis.

2.3 The documentation as specified per requirement R2.1 and R2.2 shall be publicly posted no later than 30 calendar days prior to the beginning of Year One.

M2 Each Planning Coordinator shall possess the documentation of its projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis on an annual basis in accordance with R2.

R3 The Planning Coordinator shall identify any gaps between the needed amount of planning reserves defined in Requirement R1, Part 1.1 and the projected planning reserves documented in Requirement R2 *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*.

M3 Each Planning Coordinator shall possess the documentation identifying any gaps between the needed amounts of planning reserves and projected planning reserves in accordance with R3.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

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

The Applicable Entity shall keep data or evidence to show compliance with Requirements R1 through R3, and Measures M1 through M3 from the most current and prior two years.

If an Applicable Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

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

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit
Self-Certification
Spot Checking
Compliance Investigation
Self-Reporting
Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	VIOLATION SEVERITY LEVEL			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Medium	The Planning Coordinator Resource Adequacy analysis failed to consider 1 or 2 of the Resource availability characteristics subcomponents under Requirement R1, Part 1.4 and documentation of how and why they were included in the analysis or why they were not included **OR** The Planning Coordinator Resource Adequacy analysis failed to consider Transmission maintenance outage schedules and document how and why they were included in the analysis or why they were not included per Requirement R1, Part 1.5	The Planning Coordinator Resource Adequacy analysis failed to express the planning reserve margin developed from Requirement R1, Part 1.1 as a percentage of the net Median forecast peak Load per Requirement R1, Part 1.1.2 **OR** The Planning Coordinator Resource Adequacy analysis failed to include 1 of the Load forecast Characteristics subcomponents under Requirement R1, Part 1.3.1 and documentation of its use **OR**	The Planning Coordinator Resource Adequacy analysis failed to be performed or verified separately for individual years of Year One through Year Ten per Requirement R1, Part 1.2 **OR** The Planning Coordinator failed to perform an analysis or verification for one year in the 2 through 5 year period or one year in the 6 though 10 year period or both per Requirement R1, Part 1.2.2 **OR** The Planning Coordinator Resource Adequacy analysis failed to include 2 or	The Planning Coordinator failed to perform and document a Resource Adequacy analysis annually per R1. **OR** The Planning Coordinator Resource Adequacy analysis failed to calculate a Planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year analyzed for each planning period being equal to 0.1 per Requirement R1, Part 1.1 **OR**

				The Planning Coordinator Resource Adequacy analysis failed to include 1 of the Resource Characteristics subcomponents under Requirement R1, Part 1.3.2 and documentation of its use **Or** The Planning Coordinator Resource Adequacy analysis failed to document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis per Requirement R1, Part 1.7	more of the Load forecast Characteristics subcomponents under Requirement R1, Part 1.3.1 and documentation of their use **OR** The Planning Coordinator Resource Adequacy analysis failed to include 2 or more of the Resource Characteristics subcomponents under Requirement R1, Part 1.3.2 and documentation of their use **OR** The Planning Coordinator Resource Adequacy analysis failed to include Transmission limitations and documentation of its use	The Planning Coordinator failed to perform an analysis for Year One per Requirement R1, Part 1.2.1

					per Requirement R1, Part 1.3.3 **OR** The Planning Coordinator Resource Adequacy analysis failed to include assistance from other interconnected systems and documentation of its use per Requirement R1, Part 1.3.4 **OR** The Planning Coordinator Resource Adequacy analysis failed to consider 3 or more Resource availability characteristics subcomponents under Requirement R1, Part 1.4 and documentation of how and why they were included in the analysis or why they were not included	

					OR The Planning Coordinator Resource Adequacy analysis failed to document that capacity resources are appropriately accounted for in its Resource Adequacy analysis per Requirement R1, Part 1.6	
R2	Long-term Planning	Lower	The Planning Coordinator failed to publicly post the documents as specified per requirement Requirement R2, Part 2.1 and Requirement R2, Part 2.2 later than 30 calendar days prior to the beginning of Year One per Requirement R2, Part 2.3	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for one of the years in the 2 through 10 year period per Requirement R2, Part 2.1. **OR** The Planning Coordinator failed to document the Planning	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for year 1 of the 10 year period per Requirement R2, Part 2.1. **OR** The Planning Coordinator failed to document the projected Load and resource	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis per Requirement R2, Part 2.

				Reserve margin calculated per requirement R1.1 for each of the three years in the analysis per Requirement R2, Part 2.2.	capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for two or more of the years in the 2 through 10 year period per Requirement R2, Part 2.1.	
R3	Long-term Planning	Lower	None	None	None	The Planning Coordinator failed to identify any gaps between the needed amount of planning reserves and the projected planning reserves, per R3

D. Regional Variances

None

E. Interpretations

None

F. Associated Documents

None

Version History

Version	Date	Action	Change Tracking
BAL-502-RFC-02	12/04/08	ReliabilityFirst Board Approved	
BAL-502-RFC-02	08/05/09	NERC BoT Approved	
BAL-502-RFC-02	03/17/11	FERC Approved	

Standard BAL-502-RF-03

A. Introduction

1. Title: **Planning Resource Adequacy Analysis, Assessment and Documentation**

2. Number: **BAL-502-RF-03**

3. Purpose: To establish common criteria, based on "one day in ten year" loss of Load expectation principles, for the analysis, assessment and documentation of Resource Adequacy for Load in the ReliabilityFirst Corporation (RF) region

4. Applicability

4.1 Functional Entities

4.1.1 Planning Coordinator

5. Effective Date:

5.1 BAL-502-RF-03 shall become effective on the first day of the first calendar quarter that is after the date that this standard is approved by applicable regulatory authorities or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect.

B. Requirements and Measures

R1 The Planning Coordinator shall perform and document a Resource Adequacy analysis annually. The Resource Adequacy analysis shall *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*:

1.1 Calculate a planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year[1] analyzed (per R1.2) being equal to 0.1. (This is comparable to a "one day in 10 year" criterion).

1.1.1 The utilization of Direct Control Load Management or curtailment of Interruptible Demand shall not contribute to the loss of Load probability.

1.1.2 The planning reserve margin developed from R1.1 shall be expressed as a percentage of the median[2] forecast peak Net Internal Demand (planning reserve margin).

1.2 Be performed or verified separately for each of the following planning years:

[1] The annual period over which the LOLE is measured, and the resulting resource requirements are established (June 1st through the following May 31st).

[2] The median forecast is expected to have a 50% probability of being too high and 50% probability of being too low (50:50).

Deleted: C
Deleted: 2
Deleted: 12/04/08
Deleted: C
Deleted: 2
Formatted: Indent: Hanging: 0.15", Outline numbered + Level: 1 + Numbering Style: 1, 2, 3, … + Start at: 1 + Alignment: Left + Aligned at: 0" + Tab after: 0.4" + Indent at: 0.4", Tab stops: Not at 0.5"
Deleted: ¶
Formatted: Font: Not Italic
Deleted: C
Deleted: ¶
Deleted: Planning Coordinator
Formatted: Outline numbered + Level: 3 + Numbering Style: 1, 2, 3, … + Start at: 1 + Alignment: Left + Aligned at: 1" + Tab after: 1.5" + Indent at: 1.5"
Deleted: ¶
Deleted: Upon RFC Board approval ¶
Formatted: Font: Italic, Font color: Auto
Deleted: R
Deleted: R
Deleted: R
Deleted: R
Deleted: December 4th
Deleted: 08

1.2.1 Perform an analysis for Year One.

1.2.2 Perform an analysis or verification at a minimum for one year in the 2 through 5 year period and at a minimum one year in the 6 though 10 year period.

1.2.2.1 If the analysis is verified, the verification must be supported by current or past studies for the same planning year.

1.3 Include the following subject matter and documentation of its use:

1.3.1 Load forecast characteristics:

1.3.1.1 Median (50:50) forecast peak Load.

1.3.1.2 Load forecast uncertainty (reflects variability in the Load forecast due to weather and regional economic forecasts).

1.3.1.3 Load diversity.

1.3.1.4 Seasonal Load variations.

1.3.1.5 Daily demand modeling assumptions (firm, interruptible).

1.3.1.6 Contractual arrangements concerning curtailable/Interruptible Demand.

1.3.2 Resource characteristics:

1.3.2.1 Historic resource performance and any projected changes

1.3.2.2 Seasonal resource ratings

1.3.2.3 Modeling assumptions of firm capacity purchases from and sales to entities outside the Planning Coordinator area.

1.3.2.4 Resource planned outage schedules, deratings, and retirements.

1.3.2.5 Modeling assumptions of intermittent and energy limited resource such as wind and cogeneration.

1.3.2.6 Criteria for including planned resource additions in the analysis

1.3.3 Transmission limitations that prevent the delivery of generation reserves

1.3.3.1 Criteria for including planned Transmission Facility additions in the analysis

Deleted: C
Deleted: 2
Deleted: 12/04/08
Deleted: R
Deleted: R
Deleted: R
Deleted: R
Deleted: R
Formatted: Indent: Left: 1.5", No bullets or numbering
Formatted: Indent: Left: 1.5", Hanging: 0.5", No bullets or numbering
Formatted: Indent: Left: 1.5", Hanging: 0.5"
Deleted: R
Formatted: Indent: Left: 1.5", No bullets or numbering
Formatted: Indent: Left: 1.5", Hanging: 0.5"
Formatted: Indent: Left: 1.5", Hanging: 0.5"
Formatted: Indent: Left: 1", First line: 0.5"
Deleted: R
Deleted: R
Deleted: December 4th
Deleted: 08

1.3.4 Assistance from other interconnected systems including multi-area assessment considering Transmission limitations into the study area.

1.4 Consider the following resource availability characteristics and document how and why they were included in the analysis or why they were not included:

1.4.1 Availability and deliverability of fuel.

1.4.2 Common mode outages that affect resource availability

1.4.3 Environmental or regulatory restrictions of resource availability.

1.4.4 Any other demand (Load) response programs not included in R1.3.1.

1.4.5 Sensitivity to resource outage rates.

1.4.6 Impacts of extreme weather/drought conditions that affect unit availability.

1.4.7 Modeling assumptions for emergency operation procedures used to make reserves available.

1.4.8 Market resources not committed to serving Load (uncommitted resources) within the Planning Coordinator area.

1.5 Consider Transmission maintenance outage schedules and document how and why they were included in the Resource Adequacy analysis or why they were not included

1.6 Document that capacity resources are appropriately accounted for in its Resource Adequacy analysis

1.7 Document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis

M1 Each Planning Coordinator shall possess the documentation that a valid Resource Adequacy analysis was performed or verified in accordance with R1

R2 The Planning Coordinator shall annually document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis *[Violation Risk Factor: Lower]* *[Time Horizon: Long-term Planning]*.

2.1 This documentation shall cover each of the years in Year One through ten.

2.2 This documentation shall include the Planning Reserve margin calculated per requirement R1.1 for each of the three years in the analysis.

Deleted: C
Deleted: 2
Deleted: 12/04/08
Deleted: R
Deleted: R
Formatted: Indent: Left: 1", No bullets or numbering
Formatted: Indent: Left: 1", Hanging: 0.5"
Deleted: R
Deleted: R
Deleted: R
Formatted: Indent: Left: 0", First line: 0"
Deleted:
Formatted: Indent: Left: 0", First line: 0"
Deleted: R
Deleted: R
Deleted: R
Deleted: December 4th
Deleted: 08

2.3 The documentation as specified per requirement R2.1 and R2.2 shall be publicly posted no later than 30 calendar days prior to the beginning of Year One.

M2 Each Planning Coordinator shall possess the documentation of its projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis on an annual basis in accordance with R2.

R3 The Planning Coordinator shall identify any gaps between the needed amount of planning reserves defined in Requirement R1, Part 1.1 and the projected planning reserves documented in Requirement R2 *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning].*

M3 Each Planning Coordinator shall possess the documentation identifying any gaps between the needed amounts of planning reserves and projected planning reserves in accordance with R3.

C. Compliance

5. Compliance Monitoring Process

5.1. Compliance Monitoring Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

5.2. Evidence Retention

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

The Applicable Entity shall keep data or evidence to show compliance with Requirements R1 through R3, and Measures M1 through M3 from the most current and prior two years.

If an Applicable Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

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

5.3. Compliance Monitoring and Assessment Processes

Compliance Audit
Self-Certification
Spot Checking
Compliance Investigation
Self-Reporting
Complaint

5.4. Additional Compliance Information

None

Deleted: C
Deleted: 2
Deleted: 12/04/08
Deleted: R
Formatted: Font: Not Bold
Deleted: ¶
Measures¶
¶
M1 . Each Planning Coordinator shall possess the documentation that a valid Resource Adequacy analysis was performed or verified in accordance with R1¶
¶
M2 . Each Planning Coordinator shall possess the documentation of its projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis on an annual basis in accordance with R2.¶
¶
Formatted: Indent: Left: 0.25", No bullets or numbering
Deleted: Responsibility
Deleted: Compliance Monitor - ReliabilityFirst Corporation
Formatted: Font: Not Italic
Deleted: <#>Compliance Monitoring Period and Reset Timeframe¶
One calendar year¶
¶
Deleted: <#>Data
Formatted: Font: 11 pt
Deleted:
Formatted: Indent: Left: 0.88"
Deleted: Planning Coordinator
Deleted: retain information
Deleted:
Formatted: Indent: Left: 0.85", No bullets or numbering
Deleted: The Compliance Monitor shall retain any audit data for five years.
Formatted: Font: Bold
Formatted: Outline numbered + Level: 2 + Numbering Style: 1, 2, 3, … + Start at: 1 + Alignment: Left + Aligned at: 0.5" + Tab after: 0.85" + Indent at: 0.85"
Formatted: Indent: Left: 0.85", No bullets or numbering
Formatted: Indent: Left: 0.85"
Formatted: Font: Bold
Formatted: Outline numbered + Level: 2 + Numbering Style: 1, 2, 3, … + Start at: 1 + Alignment: Left + Aligned at: 0.5" + Tab after: 0.85" + Indent at: 0.85"
Formatted: Font: Not Bold
Formatted: Indent: Left: 0.85"
Deleted: December 4th
Deleted: 08

Table of Compliance Elements

R #	Time Horizon	VRF	VIOLATION SEVERITY LEVEL			
			Lower VSL	Moderate VSL	High VSL	
R1	Long-term Planning	Medium	The Planning Coordinator Resource Adequacy analysis failed to consider 1 or 2 of the Resource availability characteristics subcomponents under Requirement R1, Part 1.4 and documentation of how and why they were included in the analysis or why they were not included **OR** The Planning Coordinator Resource Adequacy analysis failed to consider Transmission maintenance outage schedules and document how and why they were included in the analysis or why they were not included per Requirement R1, Part 1.5	The Planning Coordinator Resource Adequacy analysis failed to express the planning reserve margin developed from Requirement R1, Part 1.1 as a percentage of the net Median forecast peak Load per Requirement R1, Part 1.1.2 **OR** The Planning Coordinator Resource Adequacy analysis failed to include 1 of the Load forecast Characteristics subcomponents under Requirement R1, Part 1.3.1 and documentation of its use **OR**	The Planning Coordinator Resource Adequacy analysis failed to be performed or verified separately for individual years of Year One through Year Ten per Requirement R1, Part 1.2 **OR** The Planning Coordinator failed to perform an analysis or verification for one year in the 2 through 5 year period or one year in the 6 though 10 year period or both per Requirement R1, Part 1.2.2 **OR** The Planning Coordinator Resource Adequacy analysis failed to include 2 or	The Pla Coordi perform Resour analysi R1. **OR** The Pla Coordi Adequacy analysis failed to calculate a Planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year analyzed for eac being equal to 0.1 per Requirement R1, Part 1.1 **OR**

Deleted: C
Deleted: 2
Deleted: 12/04/08
Deleted: Violation Severity Levels¶
Formatted: Indent: Left: 0", First line: 0"
Formatted: Width: 14.29", Height: 8.5"
Formatted Table
Deleted: Req. Number
Deleted: LOWER
Deleted: MODERATE
Deleted: HIGH
Deleted: SEVERE
Deleted: ¶
Deleted: R
Deleted: R
Deleted: R
Deleted: R
Deleted: R
Deleted: R
Deleted: R
Deleted: R
Deleted: December 4th
Deleted: 08

				The Planning Coordinator Resource Adequacy analysis failed to include 1 of the Resource Characteristics subcomponents under Requirement R1, Part 1.3.2 and documentation of its use **Or** The Planning Coordinator Resource Adequacy analysis failed to document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis per Requirement R1, Part 1.7	more of the Load forecast Characteristics subcomponents under Requirement R1, Part 1.3.1 and documentation of their use **OR** The Planning Coordinator Resource Adequacy analysis failed to include 2 or more of the Resource Characteristics subcomponents under Requirement R1, Part 1.3.2 and documentation of their use **OR** The Planning Coordinator Resource Adequacy analysis failed to include Transmission limitations and documentation of its use	The Planning Coordinator failed to perform an analysis for Year One per Requirement R1, Part 1.2.1

Deleted: C
Deleted: 2
Deleted: 12/04/08
Deleted: R
Deleted: R
Deleted: R
Deleted: R
Deleted: R
Deleted: December 4th
Deleted: 08

					per Requirement R1, Part 1.3.3 **OR** The Planning Coordinator Resource Adequacy analysis failed to include assistance from other interconnected systems and documentation of its use per Requirement R1, Part 1.3.4 **OR** The Planning Coordinator Resource Adequacy analysis failed to consider 3 or more Resource availability characteristics subcomponents under Requirement R1, Part 1.4 and documentation of how and why they were included in the analysis or why they were not included	

Deleted: C
Deleted: 2
Deleted: 12/04/08
Deleted: R
Deleted: R
Deleted: R
Deleted: December 4th
Deleted: 08

					OR The Planning Coordinator Resource Adequacy analysis failed to document that capacity resources are appropriately accounted for in its Resource Adequacy analysis per Requirement R1, Part 1.6	
R2	Long-term Planning	Lower	The Planning Coordinator failed to publicly post the documents as specified per requirement Requirement R2, Part 2.1 and Requirement R2, Part 2.2 later than 30 calendar days prior to the beginning of Year One per Requirement R2, Part 2.3	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for one of the years in the 2 through 10 year period per Requirement R2, Part 2.1. **OR** The Planning Coordinator failed to document the Planning	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for year 1 of the 10 year period per Requirement R2, Part 2.1. **OR** The Planning Coordinator failed to document the projected Load and resource	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constra identifi Resource Adequacy analysis per Requir

Deleted: C
Deleted: 2
Deleted: 12/04/08
Deleted: R
Deleted: R
Deleted: R
Deleted: R
Deleted: R
Deleted: R
Deleted: December 4th
Deleted: 08

				Reserve margin calculated per requirement R1.1 for each of the three years in the analysis per Requirement R2, Part 2.2.	capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for two or more of the years in the 2 through 10 year period per Requirement R2, Part 2.1.	
R3	Long-term Planning	Lower	None	None	None	The Planning Coordinator failed to identify any gaps between the needed amount of planning reserves and the projected planning reserves, per R3

Deleted: C
Deleted: 2
Deleted: 12/04/08
Deleted: R
Deleted: R
Deleted: December 4th
Deleted: 08

Deleted: C

Deleted: 2

Deleted: 12/04/08

D. Regional Variances

None

Deleted: None

E. Interpretations

Deleted: Interpretations

None

Deleted: None

F. Associated Documents

Deleted: Associated Documents

None

Deleted: None

Deleted: **Definitions:**¶
Resource Adequacy - the ability of supply-side and demand-side resources to meet the aggregate electrical demand (including losses).¶
¶
Net Internal Demand - Total of all end-use customer demand and electric system losses within specified metered boundaries, less Direct Control Load Management and Interruptible Demand.¶
¶
Peak Period - A period consisting of two (2) or more calendar months but less than seven (7) calendar months, which includes the period during which the responsible entity's annual peak demand is expected to occur¶
¶
Year One - The planning year that begins with the upcoming annual Peak Period.¶
¶
The following definitions were extracted from the February 12th, 2008 NERC Glossary of Terms:¶
¶
¶
Direct Control Load Management – Demand-Side Management that is under the direct control of the system operator. DCLM may control the electric supply to individual appliances or equipment on customer premises. DCLM as defined here does not include Interruptible Demand.¶
¶
Facility - 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.)¶
¶
Interruptible Demand - Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment.¶
¶
Load - An end-use device or customer that receives power from the electric system.¶
…

Version History

Version	Date	Action	Change Tracking
BAL-502-RFC-02	12/04/08	ReliabilityFirst Board Approved	
BAL-502-RFC-02	08/05/09	NERC BoT Approved	
BAL-502-RFC-02	03/17/11	FERC Approved	

Deleted: 1st Draft

Deleted: 06/24/08 Through 07/23/08

Deleted: Posted for 1st Comment Period

Deleted: 2nd Draft

Deleted: 08/18/08 Through 09/16/08

Deleted: Posted for 2nd Comment Period

Deleted: 3rd Draft

Deleted: 10/16/08 Through 10/30/08

Deleted: Posted for 15-Day Category Ballot

Deleted: BAL-502-RFC-02 3rd Draft

Deleted: 12/04/08

Deleted: ReliabilityFirst Board Approved

Formatted: Font: Not Italic

Deleted: December 4th

Deleted: 08

Deleted: RFC-02 . 12/04/08

A. Introduction

1. Title: **Planning Resource Adequacy Analysis, Assessment and Documentation**

2. Number: **BAL-502-RF-03**

3. Purpose: To establish common criteria, based on "one day in ten year" loss of Load expectation principles, for the analysis, assessment and documentation of Resource Adequacy for Load in the ReliabilityFirst Corporation (RF) region

4. Applicability

4.1 Functional Entities

4.1.1 Planning Coordinator

5. Effective Date:

5.1 BAL-502-RF-03 shall become effective on the first day of the first calendar quarter that is after the date that this standard is approved by applicable regulatory authorities or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect.

B. Requirements and Measures

R1 The Planning Coordinator shall perform and document a Resource Adequacy analysis annually. The Resource Adequacy analysis shall *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*:

1.1 Calculate a planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year[1] analyzed (per R1.2) being equal to 0.1. (This is comparable to a "one day in 10 year" criterion).

1.1.1 The utilization of Direct Control Load Management or curtailment of Interruptible Demand shall not contribute to the loss of Load probability.

1.1.2 The planning reserve margin developed from R1.1 shall be expressed as a percentage of the median[2] forecast peak Net Internal Demand (planning reserve margin).

1.2 Be performed or verified separately for each of the following planning years:

[1] The annual period over which the LOLE is measured, and the resulting resource requirements are established (June 1st through the following May 31st).

[2] The median forecast is expected to have a 50% probability of being too high and 50% probability of being too low (50:50).

Style Definition: Section
Style Definition: Requirement
Style Definition: List Number: Outline numbered + Level: 1 + Numbering Style: 1, 2, 3, ... + Start at: 1 + Alignment: Left + Aligned at: 0" + Tab after: 0.4" + Indent at: 0.4"
Style Definition: Measure
Style Definition: Style1
Deleted: RFC-02
Formatted: Indent: Hanging: 0.15", Outline numbered + Level: 1 + Numbering Style: 1, 2, 3, ... + Start at: 1 + Alignment: Left + Aligned at: 0" + Tab after: 0.4" + Indent at: 0.4", Tab stops: 1.25", Left
Deleted: ¶
Formatted: Font: Not Italic
Deleted: RFC
Formatted: Font: Bold
Deleted: ¶
Formatted: Tab stops: 0.38", Left + Not at 0.5"
Formatted
Deleted:
Formatted: Font: Bold
Deleted: ¶
Formatted: Indent: Left: 0.25", Tab stops: 0.44", Left + Not at 0.5"
Deleted: 5.1 . Upon RFC Board approval ¶ ¶
Formatted: Font: Italic, Font color: Auto
Deleted: R1
Deleted: R1
Deleted: R1
Deleted: R1
Deleted: December 4th, 2008

Deleted: RFC-02 . 12/04/08

1.2.1 Perform an analysis for Year One.

Deleted: R1

1.2.2 Perform an analysis or verification at a minimum for one year in the 2 through 5 year period and at a minimum one year in the 6 though 10 year period.

Deleted: R1

1.2.2.1 If the analysis is verified, the verification must be supported by current or past studies for the same planning year.

Deleted: R1

1.3 Include the following subject matter and documentation of its use:

Deleted: R1

1.3.1 Load forecast characteristics:

Deleted: R1

1.3.1.1 Median (50:50) forecast peak Load.

Formatted: Indent: Left: 1.5", No bullets or numbering

1.3.1.2 Load forecast uncertainty (reflects variability in the Load forecast due to weather and regional economic forecasts).

Formatted: Indent: Left: 1.5", Hanging: 0.5", No bullets or numbering

1.3.1.3 Load diversity.

Formatted: Indent: Left: 1.5", No bullets or numbering

1.3.1.4 Seasonal Load variations.

1.3.1.5 Daily demand modeling assumptions (firm, interruptible).

1.3.1.6 Contractual arrangements concerning curtailable/Interruptible Demand.

Formatted: Indent: Left: 1.5", Hanging: 0.5", No bullets or numbering

1.3.2 Resource characteristics:

Deleted: R1

1.3.2.1 Historic resource performance and any projected changes

Formatted: Indent: Left: 1.5", No bullets or numbering

1.3.2.2 Seasonal resource ratings

1.3.2.3 Modeling assumptions of firm capacity purchases from and sales to entities outside the Planning Coordinator area.

Formatted: Indent: Left: 1.5", Hanging: 0.5", No bullets or numbering

1.3.2.4 Resource planned outage schedules, deratings, and retirements.

Formatted: Indent: Left: 1.5", No bullets or numbering

1.3.2.5 Modeling assumptions of intermittent and energy limited resource such as wind and cogeneration.

Formatted: Indent: Left: 1.5", Hanging: 0.5", No bullets or numbering, Tab stops: Not at 2"

1.3.2.6 Criteria for including planned resource additions in the analysis

1.3.3 Transmission limitations that prevent the delivery of generation reserves

Deleted: R1

1.3.3.1 Criteria for including planned Transmission Facility additions in the analysis

Deleted: R1

Deleted: December 4th, 2008

Deleted: RFC-02 . 12/04/08

1.3.4 Assistance from other interconnected systems including multi-area assessment considering Transmission limitations into the study area.

Deleted: R1

1.4 Consider the following resource availability characteristics and document how and why they were included in the analysis or why they were not included:

Deleted: R1

1.4.1 Availability and deliverability of fuel.

Formatted: Indent: Left: 1", No bullets or numbering

1.4.2 Common mode outages that affect resource availability

1.4.3 Environmental or regulatory restrictions of resource availability.

1.4.4 Any other demand (Load) response programs not included in R1.3.1.

1.4.5 Sensitivity to resource outage rates.

1.4.6 Impacts of extreme weather/drought conditions that affect unit availability.

Formatted: Indent: Left: 1", Hanging: 0.5", No bullets or numbering

1.4.7 Modeling assumptions for emergency operation procedures used to make reserves available.

1.4.8 Market resources not committed to serving Load (uncommitted resources) within the Planning Coordinator area.

1.5 Consider Transmission maintenance outage schedules and document how and why they were included in the Resource Adequacy analysis or why they were not included

Deleted: R1

1.6 Document that capacity resources are appropriately accounted for in its Resource Adequacy analysis

Deleted: R1

1.7 Document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis

Deleted: R1

Deleted: ¶

M1 Each Planning Coordinator shall possess the documentation that a valid Resource Adequacy analysis was performed or verified in accordance with R1

Formatted: Normal, Indent: Left: 0", Right: 0.5", Space Before: 6 pt, Don't adjust space between Latin and Asian text, Don't adjust space between Asian text and numbers

Moved (insertion) [1]

Formatted: Normal, Indent: Left: 0", Right: 0.5", Space Before: 6 pt, Don't adjust space between Latin and Asian text, Don't adjust space between Asian text and numbers

R2 The Planning Coordinator shall annually document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*.

2.1 This documentation shall cover each of the years in Year One through ten.

Deleted: R2

2.2 This documentation shall include the Planning Reserve margin calculated per requirement R1.1 for each of the three years in the analysis.

Deleted: R2

Deleted: December 4th, 2008

Deleted: RFC-02 . 12/04/08

2.3 The documentation as specified per requirement R2.1 and R2.2 shall be publicly posted no later than 30 calendar days prior to the beginning of Year One.

Deleted: R2

Formatted: Indent: Left: 0.25", Hanging: 0.25"

M2 Each Planning Coordinator shall possess the documentation of its projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis on an annual basis in accordance with R2.

Deleted: <#>Measures¶

Moved up [1]: <#>¶
M1 . Each Planning Coordinator shall possess the documentation that a valid Resource Adequacy analysis was performed or verified in accordance with R1¶
¶

R3 The Planning Coordinator shall identify any gaps between the needed amount of planning reserves defined in Requirement R1, Part 1.1 and the projected planning reserves documented in Requirement R2 *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning].*

Formatted: Font: Not Bold

Formatted: Requirement, Indent: Left: 0.25", Hanging: 0.25", Tab stops: 0.63", Left

M3 Each Planning Coordinator shall possess the documentation identifying any gaps between the needed amounts of planning reserves and projected planning reserves in accordance with R3.

C. Compliance

1. Compliance Monitoring Process

Formatted: Indent: Hanging: 0.09"

1.1. Compliance Enforcement Authority

Deleted: Monitoring Responsibility

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

Deleted: Compliance Monitor - Reliability*First* Corporation ¶
¶
Compliance Monitoring Period and Reset Timeframe¶
One calendar year¶
¶
Data

1.2. Evidence Retention

Formatted: Indent: Left: 0.56", Hanging: 0.31"

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.

Deleted: . The Planning Coordinator shall retain information from the most current and prior two years.¶
¶
. The Compliance Monitor shall retain any audit data for five years.¶
¶
Violation Severity Levels¶
¶

The Applicable Entity shall keep data or evidence to show compliance with Requirements R1 through R3, and Measures M1 through M3 from the most current and prior two years.

If an Applicable Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

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

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit
Self-Certification
Spot Checking
Compliance Investigation
Self-Reporting
Complaint

1.4. Additional Compliance Information

Deleted: December 4th, 2008

Deleted: RFC-02 . 12/04/08

None

Deleted: December 4th, 2008

Deleted: RFC-02 12/04/08

Table of Compliance Elements

R #	Time Horizon	VRF	VIOLATION SEVERITY LEVEL			
			Lower VSL	Moderate VSL	High VSL	S
R1	Long-term Planning	Medium	The Planning Coordinator Resource Adequacy analysis failed to consider 1 or 2 of the Resource availability characteristics subcomponents under Requirement R1, Part 1.4 and documentation of how and why they were included in the analysis or why they were not included **OR** The Planning Coordinator Resource Adequacy analysis failed to consider Transmission maintenance outage schedules and document how and why they were included in the analysis or why they were not included per Requirement R1, Part 1.5	The Planning Coordinator Resource Adequacy analysis failed to express the planning reserve margin developed from Requirement R1, Part 1.1 as a percentage of the net Median forecast peak Load per Requirement R1, Part 1.1.2 **OR** The Planning Coordinator Resource Adequacy analysis failed to include 1 of the Load forecast Characteristics subcomponents under Requirement R1, Part 1.3.1 and documentation of its use **OR**	The Planning Coordinator Resource Adequacy analysis failed to be performed or verified separately for individual years of Year One through Year Ten per Requirement R1, Part 1.2 **OR** The Planning Coordinator failed to perform an analysis or verification for one year in the 2 through 5 year period or one year in the 6 though 10 year period or both per Requirement R1, Part 1.2.2 **OR** The Planning Coordinator Resource Adequacy analysis failed to include 2 or	The Pl Coordi perform Resour analysi R1. **OR** The Pl Coordi Adequ failed t Planni that wi sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year analyzed for each planning period being equal to 0.1 per Requir 1.1 **OR**

Deleted: December 4th, 2008

				The Planning Coordinator Resource Adequacy analysis failed to include 1 of the Resource Characteristics subcomponents under Requirement R1, Part 1.3.2 and documentation of its use **Or** The Planning Coordinator Resource Adequacy analysis failed to document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis per Requirement R1, Part 1.7	more of the Load forecast Characteristics subcomponents under Requirement R1, Part 1.3.1 and documentation of their use **OR** The Planning Coordinator Resource Adequacy analysis failed to include 2 or more of the Resource Characteristics subcomponents under Requirement R1, Part 1.3.2 and documentation of their use **OR** The Planning Coordinator Resource Adequacy analysis failed to include Transmission limitations and documentation of its use	The Planning Coordinator failed to perform an analysis for Year One Requirement R1, Part 1.2.1

Deleted: RFC-02 12/04/08

Deleted: R1

Deleted: R1

Deleted: R1

Deleted: R1

Deleted: R1

Deleted: December 4th, 2008

					per Requirement R1, Part 1.3.3 **OR** The Planning Coordinator Resource Adequacy analysis failed to include assistance from other interconnected systems and documentation of its use per Requirement R1, Part 1.3.4 **OR** The Planning Coordinator Resource Adequacy analysis failed to consider 3 or more Resource availability characteristics subcomponents under Requirement R1, Part 1.4 and documentation of how and why they were included in the analysis or why they were not included	

Deleted: RFC-02 12/04/08

Deleted: R1

Deleted: R1

Deleted: R1

Deleted: December 4th, 2008

Deleted: RFC-02 12/04/08

					OR The Planning Coordinator Resource Adequacy analysis failed to document that capacity resources are appropriately accounted for in its Resource Adequacy analysis per Requirement R1, Part 1.6	
R2	Long-term Planning	Lower	The Planning Coordinator failed to publicly post the documents as specified per requirement Requirement R2, Part 2.1 and Requirement R2, Part 2.2 later than 30 calendar days prior to the beginning of Year One per Requirement R2, Part 2.3	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for one of the years in the 2 through 10 year period per Requirement R2, Part 2.1. **OR** The Planning Coordinator failed to document the Planning	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for year 1 of the 10 year period per Requirement R2, Part 2.1. **OR** The Planning Coordinator failed to document the projected Load and resource	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Tran constra identified in the Resource Adequacy analysis per Requir

Deleted: R2

Formatted: Font color: Black

Deleted: R2

Formatted: Font color: Black

Deleted: R2

Deleted: R2

Deleted: December 4th, 2008

				Reserve margin calculated per requirement R1.1 for each of the three years in the analysis per Requirement R2, Part 2.2.	capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for two or more of the years in the 2 through 10 year period per Requirement R2, Part 2.1.	
R3	Long-term Planning	Lower	None	None	None	The Pla Coordi identify betwee amount reserve project reserve

Deleted: RFC-02 12/04/08

Deleted: R2

Formatted: Font color: Black

Deleted: ¶
¶
¶
Definitions:¶
Resource Adequacy - the ability of supply-side and demand-side resources to meet the aggregate electrical demand (including losses).¶
¶
Net Internal Demand - Total of all end-use customer demand and electric system losses within specified metered boundaries, less Direct Control Load Management and Interruptible Demand.¶
¶
Peak Period - A period consisting of two (2) or more calendar months but less than seven (7) calendar months, which includes the period during which the responsible entity's annual peak demand is expected to occur¶
¶
Year One - The planning year that begins with the upcoming annual Peak Period.¶
¶
The following definitions were extracted from the February 12th, 2008 NERC Glossary of Terms:¶
¶
¶
Direct Control Load Management – Demand-Side Management that is under the direct control of the system operator. DCLM may control the electric supply to individual appliances or equipment on customer premises. DCLM as defined here does not include Interruptible Demand.¶
¶
Facility - 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.)¶
¶
Interruptible Demand - Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment.¶
¶
Load - An end-use device or customer that receives power from the electric system.¶
Transmission - An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems. ¶

Deleted: December 4th, 2008

Deleted: RFC-02 12/04/08

Formatted: Right: 4.29", Width: 11.79"

D. Regional Variances

None

E. Interpretations

None

F. Associated Documents

None

Version History

Version	Date	Action	Change Tracking
BAL-502-RFC-02	12/04/08	ReliabilityFirst Board Approved	
BAL-502-RFC-02	08/05/09	NERC BoT Approved	
BAL-502-RFC-02	03/17/11	FERC Approved	

Formatted Table

Deleted: 1st Draft

Deleted: 06/24/08 Through 07/23

Moved (insertion) [2]

Formatted: Font: Not Italic

Deleted: Posted for 1st Comment Period

Deleted: 2nd Draft

Deleted: 18/08 Through

Deleted: /16/08

Deleted: Posted for 2nd Comment Period

Deleted: 3rd Draft

Deleted: 10/16/08 Through 10/30/08

Deleted: Posted for 15-Day Category Ballot

Deleted: BAL-502-RFC-02 3rd Draft

Deleted: 12/04/08

Moved up [2]: ReliabilityFirst Board Approved

Formatted: Font: Not Italic

Deleted: December 4th, 2008

Draft Planning Resource Adequacy Analysis, Assessment and Documentation (BAL-502-RF-03) Implementation Plan

Requested Approvals

- None

Requested Retirements

- BAL-502-RFC-02

Prerequisite Approval

- None

Revisions to Defined Terms in the NERC Glossary

- None

Effective Date

- BAL-502-RF-03 shall become effective on the first day of the first calendar quarter that is after the date that this standard is approved by applicable regulatory authorities or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect.

Draft Planning Resource Adequacy Analysis, Assessment and Documentation (BAL-502-RF-03) Ballot Pool Registration Form

Individuals registered in the ReliabilityFirst Ballot Body are allowed to join the Planning Resource Adequacy Analysis, Assessment and Documentation Ballot Pool beginning September 12, 2016 through the close of business of the seventh day of the 15-Day pre-ballot posting period.

Individuals whom are not currently registered in the ReliabilityFirst Ballot Body must first submit a Ballot Body registration form, and be approved as a Ballot Body member prior to joining the associated Planning Resource Adequacy Analysis, Assessment and Documentation Ballot Pool.

Please complete this Ballot Pool registration form and send it to the Standards Process Manager. Upon review of your registration, you will receive a confirmation email. Confirmation may take up to 24 hours. If you have any questions, please contact Anthony Jablonski anthony.jablonski@rfirst.org at 216-503-0693.

Name:
Company:
Email:
Phone:

Announcement: Planning Resource Adequacy Analysis, Assessment and Documentation (BAL-502-RF-03) Posted for 15-Days Prior to Category Ballot (January 3, 2017 thru January 17, 2017)

The ReliabilityFirst Standards Committee announces that the draft Planning Resource Adequacy Analysis, Assessment and Documentation (BAL-502-RF-03) standards and the supporting documents are currently posted for the required 15-days prior to Category Ballot beginning January 3, 2017. The main purpose of the drafting effort was revise the existing FERC approved ReliabilityFirst Planning Resource Adequacy Analysis, Assessment and Documentation (BAL-502-RFC-02) Standard to address two FERC Directives as noted in FERC Order No 747 (FERC Order initially approving the Standard). The two FERC directives include (1) add time horizons to the two main requirements, and (2) consider modifying the regional Reliability Standard to include a requirement that the planning coordinators identify any gap between the needed amount of planning reserves defined in Requirement R1.1 and the planning reserves determined from the resource adequacy analysis. The Standard Drafting Team also made miscellaneous non-substantive formatting changes to better align with the format of NERC Reliability Standards.

The draft ReliabilityFirst BAL-502-RF-03 standard, draft Implementation Plan, responses to comments, redline of changes compared original Standards and associated supporting documents can be found on the BAL-502-RF-03 website. Once the 15-day pre-ballot posting is completed, the 15-day Category Ballot for the ReliabilityFirst BAL-502-RF-03 drafting effort is expected to begin on January 18, 2017.

Also, per the ReliabilityFirst Reliability Standards Development Procedure, entities may join the Ballot Pool for BAL-502-RF-03 effort through the close of business of the seventh day of the 15-Day pre-ballot posting period (Ballot Pool closes at 11:59 PM Central Time (CT) on January 9, 2017). Please note that individuals must be registered in the ReliabilityFirst Ballot Body first in order to join the BAL-502-RF-03 Ballot Pool. If you need to register in the ReliabilityFirst Ballot Body, please navigate to the Registered Ballot Body webpage and submit the Ballot Body registration form.

Once again we would like to thank you for your participation in the ReliabilityFirst Regional Standards drafting process. If you have any questions, please contact Anthony Jablonski anthony.jablonski@rfirst.org at 216-503-0693. Thank you and have a great day.

A. Introduction

1. Title: **Planning Resource Adequacy Analysis, Assessment and Documentation**

2. Number: **BAL-502-RF-03**

3. Purpose: To establish common criteria, based on "one day in ten year" loss of Load expectation principles, for the analysis, assessment and documentation of Resource Adequacy for Load in the ReliabilityFirst Corporation (RF) region

4. Applicability

4.1 Functional Entities

4.1.1 Planning Coordinator

5. Effective Date:

5.1 BAL-502-RF-03 shall become effective on the first day of the first calendar quarter that is after the date that this standard is approved by applicable regulatory authorities or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect.

B. Requirements and Measures

R1 The Planning Coordinator shall perform and document a Resource Adequacy analysis annually. The Resource Adequacy analysis shall *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*:

1.1 Calculate a planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year[1] analyzed (per R1.2) being equal to 0.1. (This is comparable to a "one day in 10 year" criterion).

1.1.1 The utilization of Direct Control Load Management or curtailment of Interruptible Demand shall not contribute to the loss of Load probability.

1.1.2 The planning reserve margin developed from R1.1 shall be expressed as a percentage of the median[2] forecast peak Net Internal Demand (planning reserve margin).

1.2 Be performed or verified separately for each of the following planning years:

[1] The annual period over which the LOLE is measured, and the resulting resource requirements are established (June 1st through the following May 31st).

[2] The median forecast is expected to have a 50% probability of being too high and 50% probability of being too low (50:50).

1.2.1 Perform an analysis for Year One.

1.2.2 Perform an analysis or verification at a minimum for one year in the 2 through 5 year period and at a minimum one year in the 6 though 10 year period.

1.2.2.1 If the analysis is verified, the verification must be supported by current or past studies for the same planning year.

1.3 Include the following subject matter and documentation of its use:

1.3.1 Load forecast characteristics:

1.3.1.1 Median (50:50) forecast peak Load.

1.3.1.2 Load forecast uncertainty (reflects variability in the Load forecast due to weather and regional economic forecasts).

1.3.1.3 Load diversity.

1.3.1.4 Seasonal Load variations.

1.3.1.5 Daily demand modeling assumptions (firm, interruptible).

1.3.1.6 Contractual arrangements concerning curtailable/Interruptible Demand.

1.3.2 Resource characteristics:

1.3.2.1 Historic resource performance and any projected changes

1.3.2.2 Seasonal resource ratings

1.3.2.3 Modeling assumptions of firm capacity purchases from and sales to entities outside the Planning Coordinator area.

1.3.2.4 Resource planned outage schedules, deratings, and retirements.

1.3.2.5 Modeling assumptions of intermittent and energy limited resource such as wind and cogeneration.

1.3.2.6 Criteria for including planned resource additions in the analysis

1.3.3 Transmission limitations that prevent the delivery of generation reserves

1.3.3.1 Criteria for including planned Transmission Facility additions in the analysis

1.3.4 Assistance from other interconnected systems including multi-area assessment considering Transmission limitations into the study area.

1.4 Consider the following resource availability characteristics and document how and why they were included in the analysis or why they were not included:

1.4.1 Availability and deliverability of fuel.

1.4.2 Common mode outages that affect resource availability

1.4.3 Environmental or regulatory restrictions of resource availability.

1.4.4 Any other demand (Load) response programs not included in R1.3.1.

1.4.5 Sensitivity to resource outage rates.

1.4.6 Impacts of extreme weather/drought conditions that affect unit availability.

1.4.7 Modeling assumptions for emergency operation procedures used to make reserves available.

1.4.8 Market resources not committed to serving Load (uncommitted resources) within the Planning Coordinator area.

1.5 Consider Transmission maintenance outage schedules and document how and why they were included in the Resource Adequacy analysis or why they were not included

1.6 Document that capacity resources are appropriately accounted for in its Resource Adequacy analysis

1.7 Document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis

M1 Each Planning Coordinator shall possess the documentation that a valid Resource Adequacy analysis was performed or verified in accordance with R1

R2 The Planning Coordinator shall annually document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*.

2.1 This documentation shall cover each of the years in Year One through ten.

2.2 This documentation shall include the Planning Reserve margin calculated per requirement R1.1 for each of the three years in the analysis.

2.3 The documentation as specified per requirement R2.1 and R2.2 shall be publicly posted no later than 30 calendar days prior to the beginning of Year One.

M2 Each Planning Coordinator shall possess the documentation of its projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis on an annual basis in accordance with R2.

R3 The Planning Coordinator shall identify any gaps between the needed amount of planning reserves defined in Requirement R1, Part 1.1 and the projected planning reserves documented in Requirement R2 *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*.

M3 Each Planning Coordinator shall possess the documentation identifying any gaps between the needed amounts of planning reserves and projected planning reserves in accordance with R3.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

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

The Applicable Entity shall keep data or evidence to show compliance with Requirements R1 through R3, and Measures M1 through M3 from the most current and prior two years.

If an Applicable Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

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

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit
Self-Certification
Spot Checking
Compliance Investigation
Self-Reporting
Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	VIOLATION SEVERITY LEVEL			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Medium	The Planning Coordinator Resource Adequacy analysis failed to consider 1 or 2 of the Resource availability characteristics subcomponents under Requirement R1, Part 1.4 and documentation of how and why they were included in the analysis or why they were not included **OR** The Planning Coordinator Resource Adequacy analysis failed to consider Transmission maintenance outage schedules and document how and why they were included in the analysis or why they were not included per Requirement R1, Part 1.5	The Planning Coordinator Resource Adequacy analysis failed to express the planning reserve margin developed from Requirement R1, Part 1.1 as a percentage of the net Median forecast peak Load per Requirement R1, Part 1.1.2 **OR** The Planning Coordinator Resource Adequacy analysis failed to include 1 of the Load forecast Characteristics subcomponents under Requirement R1, Part 1.3.1 and documentation of its use **OR**	The Planning Coordinator Resource Adequacy analysis failed to be performed or verified separately for individual years of Year One through Year Ten per Requirement R1, Part 1.2 **OR** The Planning Coordinator failed to perform an analysis or verification for one year in the 2 through 5 year period or one year in the 6 though 10 year period or both per Requirement R1, Part 1.2.2 **OR** The Planning Coordinator Resource Adequacy analysis failed to include 2 or	The Planning Coordinator failed to perform and document a Resource Adequacy analysis annually per R1. **OR** The Planning Coordinator Resource Adequacy analysis failed to calculate a Planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year analyzed for each planning period being equal to 0.1 per Requirement R1, Part 1.1 **OR**

				The Planning Coordinator Resource Adequacy analysis failed to include 1 of the Resource Characteristics subcomponents under Requirement R1, Part 1.3.2 and documentation of its use **Or** The Planning Coordinator Resource Adequacy analysis failed to document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis per Requirement R1, Part 1.7	more of the Load forecast Characteristics subcomponents under Requirement R1, Part 1.3.1 and documentation of their use **OR** The Planning Coordinator Resource Adequacy analysis failed to include 2 or more of the Resource Characteristics subcomponents under Requirement R1, Part 1.3.2 and documentation of their use **OR** The Planning Coordinator Resource Adequacy analysis failed to include Transmission limitations and documentation of its use	The Planning Coordinator failed to perform an analysis for Year One per Requirement R1, Part 1.2.1

					per Requirement R1, Part 1.3.3 **OR** The Planning Coordinator Resource Adequacy analysis failed to include assistance from other interconnected systems and documentation of its use per Requirement R1, Part 1.3.4 **OR** The Planning Coordinator Resource Adequacy analysis failed to consider 3 or more Resource availability characteristics subcomponents under Requirement R1, Part 1.4 and documentation of how and why they were included in the analysis or why they were not included	

					OR The Planning Coordinator Resource Adequacy analysis failed to document that capacity resources are appropriately accounted for in its Resource Adequacy analysis per Requirement R1, Part 1.6	
R2	Long-term Planning	Lower	The Planning Coordinator failed to publicly post the documents as specified per requirement Requirement R2, Part 2.1 and Requirement R2, Part 2.2 later than 30 calendar days prior to the beginning of Year One per Requirement R2, Part 2.3	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for one of the years in the 2 through 10 year period per Requirement R2, Part 2.1. **OR** The Planning Coordinator failed to document the Planning	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for year 1 of the 10 year period per Requirement R2, Part 2.1. **OR** The Planning Coordinator failed to document the projected Load and resource	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis per Requirement R2, Part 2.

				Reserve margin calculated per requirement R1.1 for each of the three years in the analysis per Requirement R2, Part 2.2.	capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for two or more of the years in the 2 through 10 year period per Requirement R2, Part 2.1.	
R3	Long-term Planning	Lower	None	None	None	The Planning Coordinator failed to identify any gaps between the needed amount of planning reserves and the projected planning reserves, per R3

D. Regional Variances

None

E. Interpretations

None

F. Associated Documents

None

Version History

Version	Date	Action	Change Tracking
BAL-502-RFC-02	12/04/08	ReliabilityFirst Board Approved	
BAL-502-RFC-02	08/05/09	NERC BoT Approved	
BAL-502-RFC-02	03/17/11	FERC Approved	

Draft Planning Resource Adequacy Analysis, Assessment and Documentation (BAL-502-RF-03) Implementation Plan

Requested Approvals

- None

Requested Retirements

- BAL-502-RFC-02

Prerequisite Approval

- None

Revisions to Defined Terms in the NERC Glossary

- None

Effective Date

- BAL-502-RF-03 shall become effective on the first day of the first calendar quarter that is after the date that this standard is approved by applicable regulatory authorities or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect.

Announcement: ReliabilityFirst Planning Resource Adequacy Analysis, Assessment and Documentation (BAL-502-RF-03) Posted for 15-Day Category Ballot
(January 18, 2017 thru February 1, 2017)

The ReliabilityFirst Standards Committee announces that the draft ReliabilityFirst Planning Resource Adequacy Analysis, Assessment and Documentation (BAL-502-RF-03) standard and the supporting documents are currently posted for the 15-Day Category Ballot beginning January 18, 2017.

Only individuals whom had previously joined the BAL-502-RF-03 Ballot Pool will be eligible to cast a ballot at this time. BAL-502-RF-03 Ballot Pool members will receive a separate email with instructions on how to cast their ballot. If you have joined the BAL-502-RF-03 Ballot Pool and have not received an individual email with voting instructions or have any questions, please contact Anthony Jablonski anthony.jablonski@rfirst.org at 216-503-0693. Thank you and have a great day.

ReliabilityFirst Planning Resource Adequacy Analysis, Assessment and Documentation (BAL-502-RF-03) Ballot Pool

01/09/17

Name	Organization Name	Voter Status	Category
James Anderson	Consumers Energy Company	Primary Voter	Category 1
Scott Cunningham	Ohio Valley Electric Corporation	Primary Voter	Category 1
Chris Scanlon	Baltimore Gas and Electric Company	Primary Voter	Category 1
William J Smith	FirstEnergy Utilities	Primary Voter	Category 1
Greg Milosek	ITC Transmission	Secondary Voter	Category 1
Brenda Lyn Truhe	PPL Electric Utilities Corporation	Primary Voter	Category 1
Joseph A. Smith	Public Service Electric & Gas Company	Primary Voter	Category 1
Jeff DePriest	DTE Electric	Primary Voter	Category 2
David Greyerbiehl	Consumers Energy Company	Primary Voter	Category 2
Ruth Miller	Exelon Generation Company, LLC	Primary Voter	Category 2
Mark Koziel	FirstEnergy Utilities	Primary Voter	Category 2
Scott Hoggatt	WEC Energy Group	Primary Voter	Category 2
Sean Bodikin	Dominion Energy	Primary Voter	Category 2

John Bee	Commonwealth Edison Company	Primary Voter	Category 3
Jeff Beattie	Consumers Energy Company	Primary Voter	Category 3
Theresa Ciancio	FirstEnergy Utilities	Primary Voter	Category 3
Bob Thomas	Illinois Municipal Electric Agency	Primary Voter	Category 3
Joe O'Brien	Northern Indiana Public Service Company	Primary Voter	Category 3
William Watson	Old Dominion Electric Cooperative	Primary Voter	Category 3
Karla Jara	PSEG Energy Resources & Trade LLC	Primary Voter	Category 3
Linda Horn	WEC Energy Group	Primary Voter	Category 3
Terry Bilke	MISO	Secondary Voter	Category 4
Mark Holman	PJM Interconnection	Primary Voter	Category 4
Karl Blaszowski	Consumers Energy Company	Primary Voter	Category 4
Tony Jankowski	WEC Energy Group	Primary Voter	Category 4
Karie L. Barczak	DTE Electric	Primary Voter	Category 5
Douglas G Hohlbaugh	FirstEnergy Utilities	Primary Voter	Category 5
Jeffrey C. Mueller	Public Service Electric & Gas Company	Primary Voter	Category 5

Margaret Powell	**PECO Energy Company**	**Primary Voter**	**Category 5**
Tom Breene	**WEC Energy Group**	**Primary Voter**	**Category 5**
Julie Hegedus	**Consumers Energy Company**	**Primary Voter**	**Category 5**

A. Introduction

1. Title: **Planning Resource Adequacy Analysis, Assessment and Documentation**

2. Number: **BAL-502-RF-03**

3. Purpose: To establish common criteria, based on "one day in ten year" loss of Load expectation principles, for the analysis, assessment and documentation of Resource Adequacy for Load in the ReliabilityFirst Corporation (RF) region

4. Applicability

4.1 Functional Entities

4.1.1 Planning Coordinator

5. Effective Date:

5.1 BAL-502-RF-03 shall become effective on the first day of the first calendar quarter that is after the date that this standard is approved by applicable regulatory authorities or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect.

B. Requirements and Measures

R1 The Planning Coordinator shall perform and document a Resource Adequacy analysis annually. The Resource Adequacy analysis shall *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*:

1.1 Calculate a planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year[1] analyzed (per R1.2) being equal to 0.1. (This is comparable to a "one day in 10 year" criterion).

1.1.1 The utilization of Direct Control Load Management or curtailment of Interruptible Demand shall not contribute to the loss of Load probability.

1.1.2 The planning reserve margin developed from R1.1 shall be expressed as a percentage of the median[2] forecast peak Net Internal Demand (planning reserve margin).

1.2 Be performed or verified separately for each of the following planning years:

[1] The annual period over which the LOLE is measured, and the resulting resource requirements are established (June 1st through the following May 31st).

[2] The median forecast is expected to have a 50% probability of being too high and 50% probability of being too low (50:50).

1.2.1 Perform an analysis for Year One.

1.2.2 Perform an analysis or verification at a minimum for one year in the 2 through 5 year period and at a minimum one year in the 6 though 10 year period.

1.2.2.1 If the analysis is verified, the verification must be supported by current or past studies for the same planning year.

1.3 Include the following subject matter and documentation of its use:

1.3.1 Load forecast characteristics:

1.3.1.1 Median (50:50) forecast peak Load.

1.3.1.2 Load forecast uncertainty (reflects variability in the Load forecast due to weather and regional economic forecasts).

1.3.1.3 Load diversity.

1.3.1.4 Seasonal Load variations.

1.3.1.5 Daily demand modeling assumptions (firm, interruptible).

1.3.1.6 Contractual arrangements concerning curtailable/Interruptible Demand.

1.3.2 Resource characteristics:

1.3.2.1 Historic resource performance and any projected changes

1.3.2.2 Seasonal resource ratings

1.3.2.3 Modeling assumptions of firm capacity purchases from and sales to entities outside the Planning Coordinator area.

1.3.2.4 Resource planned outage schedules, deratings, and retirements.

1.3.2.5 Modeling assumptions of intermittent and energy limited resource such as wind and cogeneration.

1.3.2.6 Criteria for including planned resource additions in the analysis

1.3.3 Transmission limitations that prevent the delivery of generation reserves

1.3.3.1 Criteria for including planned Transmission Facility additions in the analysis

1.3.4 Assistance from other interconnected systems including multi-area assessment considering Transmission limitations into the study area.

1.4 Consider the following resource availability characteristics and document how and why they were included in the analysis or why they were not included:

1.4.1 Availability and deliverability of fuel.

1.4.2 Common mode outages that affect resource availability

1.4.3 Environmental or regulatory restrictions of resource availability.

1.4.4 Any other demand (Load) response programs not included in R1.3.1.

1.4.5 Sensitivity to resource outage rates.

1.4.6 Impacts of extreme weather/drought conditions that affect unit availability.

1.4.7 Modeling assumptions for emergency operation procedures used to make reserves available.

1.4.8 Market resources not committed to serving Load (uncommitted resources) within the Planning Coordinator area.

1.5 Consider Transmission maintenance outage schedules and document how and why they were included in the Resource Adequacy analysis or why they were not included

1.6 Document that capacity resources are appropriately accounted for in its Resource Adequacy analysis

1.7 Document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis

M1 Each Planning Coordinator shall possess the documentation that a valid Resource Adequacy analysis was performed or verified in accordance with R1

R2 The Planning Coordinator shall annually document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*.

2.1 This documentation shall cover each of the years in Year One through ten.

2.2 This documentation shall include the Planning Reserve margin calculated per requirement R1.1 for each of the three years in the analysis.

2.3 The documentation as specified per requirement R2.1 and R2.2 shall be publicly posted no later than 30 calendar days prior to the beginning of Year One.

M2 Each Planning Coordinator shall possess the documentation of its projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis on an annual basis in accordance with R2.

R3 The Planning Coordinator shall identify any gaps between the needed amount of planning reserves defined in Requirement R1, Part 1.1 and the projected planning reserves documented in Requirement R2 *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*.

M3 Each Planning Coordinator shall possess the documentation identifying any gaps between the needed amounts of planning reserves and projected planning reserves in accordance with R3.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

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

The Applicable Entity shall keep data or evidence to show compliance with Requirements R1 through R3, and Measures M1 through M3 from the most current and prior two years.

If an Applicable Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

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

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit
Self-Certification
Spot Checking
Compliance Investigation
Self-Reporting
Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	VIOLATION SEVERITY LEVEL			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Medium	The Planning Coordinator Resource Adequacy analysis failed to consider 1 or 2 of the Resource availability characteristics subcomponents under Requirement R1, Part 1.4 and documentation of how and why they were included in the analysis or why they were not included **OR** The Planning Coordinator Resource Adequacy analysis failed to consider Transmission maintenance outage schedules and document how and why they were included in the analysis or why they were not included per Requirement R1, Part 1.5	The Planning Coordinator Resource Adequacy analysis failed to express the planning reserve margin developed from Requirement R1, Part 1.1 as a percentage of the net Median forecast peak Load per Requirement R1, Part 1.1.2 **OR** The Planning Coordinator Resource Adequacy analysis failed to include 1 of the Load forecast Characteristics subcomponents under Requirement R1, Part 1.3.1 and documentation of its use **OR**	The Planning Coordinator Resource Adequacy analysis failed to be performed or verified separately for individual years of Year One through Year Ten per Requirement R1, Part 1.2 **OR** The Planning Coordinator failed to perform an analysis or verification for one year in the 2 through 5 year period or one year in the 6 though 10 year period or both per Requirement R1, Part 1.2.2 **OR** The Planning Coordinator Resource Adequacy analysis failed to include 2 or	The Planning Coordinator failed to perform and document a Resource Adequacy analysis annually per R1. **OR** The Planning Coordinator Resource Adequacy analysis failed to calculate a Planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year analyzed for each planning period being equal to 0.1 per Requirement R1, Part 1.1 **OR**

				The Planning Coordinator Resource Adequacy analysis failed to include 1 of the Resource Characteristics subcomponents under Requirement R1, Part 1.3.2 and documentation of its use **Or** The Planning Coordinator Resource Adequacy analysis failed to document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis per Requirement R1, Part 1.7	more of the Load forecast Characteristics subcomponents under Requirement R1, Part 1.3.1 and documentation of their use **OR** The Planning Coordinator Resource Adequacy analysis failed to include 2 or more of the Resource Characteristics subcomponents under Requirement R1, Part 1.3.2 and documentation of their use **OR** The Planning Coordinator Resource Adequacy analysis failed to include Transmission limitations and documentation of its use	The Planning Coordinator failed to perform an analysis for Year One per Requirement R1, Part 1.2.1

					per Requirement R1, Part 1.3.3 **OR** The Planning Coordinator Resource Adequacy analysis failed to include assistance from other interconnected systems and documentation of its use per Requirement R1, Part 1.3.4 **OR** The Planning Coordinator Resource Adequacy analysis failed to consider 3 or more Resource availability characteristics subcomponents under Requirement R1, Part 1.4 and documentation of how and why they were included in the analysis or why they were not included	

					OR The Planning Coordinator Resource Adequacy analysis failed to document that capacity resources are appropriately accounted for in its Resource Adequacy analysis per Requirement R1, Part 1.6	
R2	Long-term Planning	Lower	The Planning Coordinator failed to publicly post the documents as specified per requirement Requirement R2, Part 2.1 and Requirement R2, Part 2.2 later than 30 calendar days prior to the beginning of Year One per Requirement R2, Part 2.3	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for one of the years in the 2 through 10 year period per Requirement R2, Part 2.1. **OR** The Planning Coordinator failed to document the Planning	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for year 1 of the 10 year period per Requirement R2, Part 2.1. **OR** The Planning Coordinator failed to document the projected Load and resource	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis per Requirement R2, Part 2.

				Reserve margin calculated per requirement R1.1 for each of the three years in the analysis per Requirement R2, Part 2.2.	capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for two or more of the years in the 2 through 10 year period per Requirement R2, Part 2.1.	
R3	Long-term Planning	Lower	None	None	None	The Planning Coordinator failed to identify any gaps between the needed amount of planning reserves and the projected planning reserves, per R3

D. Regional Variances

None

E. Interpretations

None

F. Associated Documents

None

Version History

Version	Date	Action	Change Tracking
BAL-502-RFC-02	12/04/08	ReliabilityFirst Board Approved	
BAL-502-RFC-02	08/05/09	NERC BoT Approved	
BAL-502-RFC-02	03/17/11	FERC Approved	

Draft Planning Resource Adequacy Analysis, Assessment and Documentation (BAL-502-RF-03) Implementation Plan

Requested Approvals

- None

Requested Retirements

- BAL-502-RFC-02

Prerequisite Approval

- None

Revisions to Defined Terms in the NERC Glossary

- None

Effective Date

- BAL-502-RF-03 shall become effective on the first day of the first calendar quarter that is after the date that this standard is approved by applicable regulatory authorities or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect.

ReliabilityFirst Reliability Standards Voting Process Initial Category Ballot Results

Planning Resource Adequacy Analysis, Assessment and Documentation (BAL-502-RF-03)

01/18/17 through 02/01/17

Total Affirmative: 27 Total Negative: 1 Total Abstentions: 0 Total Votes Cast: 28

Total Pool Members: 30

Quorum: 93%

Vote Result: **Pass**

Category	Affirmative	Negative	Abstentions	Pool Members	Votes Cast	Votes Counted	Approval	Result
Category 1	6	1	0	7	7	7	85.71 %	Pass
Category 2	5	0	0	6	5	5	100.00 %	Pass
Category 3	7	0	0	7	7	7	100.00 %	Pass
Category 4	3	0	0	4	3	3	100.00 %	Pass
Category 5	6	0	0	6	6	6	100.00 %	Pass

Category	Vote	Member	Entity
Category 1	Affirmative	James Anderson	Consumers Energy Company
	Negative	Scott Cunningham	Ohio Valley Electric Corporation
	Affirmative	Chris Scanlon	Baltimore Gas and Electric Company
	Affirmative	William J Smith	FirstEnergy Utilities
	Affirmative	Greg Milosek	ITC Transmission
	Affirmative	Brenda Lyn Truhe	PPL Electric Utilities Corporation
	Affirmative	Joseph A. Smith	Public Service Electric & Gas Company
Category 2	Affirmative	Jeff DePriest	DTE Electric
	Affirmative	David Greyerbiehl	Consumers Energy Company
	Affirmative	Ruth Miller	Exelon Generation Company, LLC
	Affirmative	Mark Koziel	FirstEnergy Utilities
	Affirmative	Scott Hoggatt	WEC Energy Group
	No Vote	Sean Bodikin	Dominion Energy
Category 3	Affirmative	John Bee	Commonwealth Edison Company
	Affirmative	Jeff Beattie	Consumers Energy Company
	Affirmative	Theresa Ciancio	FirstEnergy Utilities
	Affirmative	Bob Thomas	Illinois Municipal Electric Agency

	Affirmative	Joe O'Brien	Northern Indiana Public Service Company
	Affirmative	William Watson	Old Dominion Electric Cooperative
	Affirmative	Karla Jara	PSEG Energy Resources & Trade LLC
Category 4	Affirmative	Terry Bilke	MISO
	Affirmative	Mark Holman	PJM Interconnection
	No Vote	Karl Blaszowski	Consumers Energy Company
	Affirmative	Tony Jankowski	WEC Energy Group
Category 5	Affirmative	Karie L. Barczak	DTE Electric
	Affirmative	Douglas G Hohlbaugh	FirstEnergy Utilities
	Affirmative	Jeffrey C. Mueller	Public Service Electric & Gas Company
	Affirmative	Margaret Powell	PECO Energy Company
	Affirmative	Tom Breene	WEC Energy Group
	Affirmative	Julie Hegedus	Consumers Energy Company

Voter Comments

Voted	Name	Entity
Negative	Scott Cunningham	Ohio Valley Electric Corporation

Comment	Response
See comments from initial posting. (The comments from the initial posting included: 1. Comment 1 - "The standard should be retired as it does not address a reliability need. There are adequate market incentives to fill the planning reserve requirement.) 2. Comment 2 – "Even if the PC identifies a gap, there is no requirement in any standard to address the gap. There are market incentives for resource owners to address the planning reserve requirement." 3. Comment 3 - Similar to the above question, the PC may document load and resources, but there is no requirement in the standards to address any gaps. 4. Comment 4 - Given that these standards must function in a market environment, market incentives should address the requirements. If they do not, we should not be fostering a market-driven system.	1. Response 1 - It is outside of the Standards Authorization Request (SAR) to determine whether the standards should be retired. During the SAR comment period (conducted 04/01/16 – 05/10/16), all individuals whom provided comments agreed with the scope of the SAR. Furthermore during the "five year review" comment period (conducted 02/29/16 – 03/09/16), all individuals who provided comments indicated the Standard should be re-affirmed. Also, the BAL-502-RF-03 standards does not require the Planning Coordinator to "fill the planning reserve requirement", rather it establishes common criteria, based on "one day in ten year" loss of Load expectation principles, for the analysis, assessment and documentation of Resource Adequacy for Load in the ReliabilityFirst Corporation region. 2. Response 2 - You are correct, if the PC identifies a gap, there is no requirement in any standard to address the gap. NERC's ability to require the building or acquisition of new generating capacity, is prohibited by section 215(a)(3) of the FPA and thus no corresponding requirement is proposed. Furthermore, the addition of the new

	requirement R3 was a result of a Directive noted in FERC Order No 747. 3. Response 3 - You are correct, if the PC identifies a gap, there is no requirement in any standard to address the gap. NERC's ability to require the building or acquisition of new generating capacity, is prohibited by section 215(a)(3) of the FPA and thus no corresponding requirement is proposed. Furthermore, the addition of the new requirement R3 was a result of a Directive noted in FERC Order No 747. 4. Response 4 - Thank you for your comment. The BAL-502-RF-03 standards does not require the Planning Coordinator to "fill the planning reserve requirement", rather it establishes common criteria, based on "one day in ten year" loss of Load expectation principles, for the analysis, assessment and documentation of Resource Adequacy for Load in the ReliabilityFirst Corporation region. NERC's ability to require the building or acquisition of new generating capacity, is prohibited by section 215(a)(3) of the FPA and thus no corresponding requirement is proposed.

Voted	Name	Entity
Affirmative	Greg Milosek	ITC

Comment	Response
ITC, on behalf of ITC Transmission, METC and Michigan Electric Coordinated Systems, is not registered as a Planning Coordinator which applies to BAL-502-RF-3, but would like to state the final recommendation should be deferred to MISO who is ITC's Planning Coordinator in the RF region.	Thank you for your comment.

Announcement: ReliabilityFirst Planning Resource Adequacy Analysis, Assessment and Documentation (BAL-502-RF-03) Category Ballot Results and 10-Day Recirculation Ballot (February 6, 2017 thru February 15, 2017)

The draft ReliabilityFirst Planning Resource Adequacy Analysis, Assessment and Documentation (BAL-502-RF-03) standard has overwhelmingly PASSED the 15-Day Category Vote (conducted January 18, 2017 through February 1, 2017) with two-thirds or greater affirmative majority of votes determined for each category along with establishing a quorum of 93%.

The Category Ballot results are listed below with the detailed results located on the ReliabilityFirst BAL-502-RF-03 website.

Category	Affirmative	Negative	Abstentions	Pool Members	Votes Cast	Votes Counted	Approval	Result
Category 1	6	1	0	7	7	7	85.71 %	Pass
Category 2	5	0	0	6	5	5	100.00 %	Pass
Category 3	7	0	0	7	7	7	100.00 %	Pass
Category 4	3	0	0	4	3	3	100.00 %	Pass
Category 5	6	0	0	6	6	6	100.00 %	Pass

Since at least one (1) Negative vote with comment during the initial ballot was cast, draft BAL-502-RF-03 standard and the supporting documents will be posted for the 10-Day Recirculation Ballot beginning February 6, 2017.

Only individuals whom had previously joined the BAL-502-RF-03 Ballot Pool will be eligible to provide a vote. In the Recirculation ballot, Ballot Pool members may indicate a revision to their original vote otherwise their vote shall remain the same as in their prior ballot (e.g. voting is done by exception, if a Ballot Pool Member is comfortable with their initial Ballot, there is no need to provide a Recirculation Ballot). **BAL-502-RF-03 Ballot Pool members will receive a separate email with instructions on how to cast their Recirculation Ballot.** If you have joined the BAL-502-RF-03 Ballot Pool and have not received an individual email with voting instructions or have any questions, please contact Anthony Jablonski anthony.jablonski@rfirst.org at 216-503-0693.

A. Introduction

1. Title: **Planning Resource Adequacy Analysis, Assessment and Documentation**

2. Number: **BAL-502-RF-03**

3. Purpose: To establish common criteria, based on "one day in ten year" loss of Load expectation principles, for the analysis, assessment and documentation of Resource Adequacy for Load in the ReliabilityFirst Corporation (RF) region

4. Applicability

4.1 Functional Entities

4.1.1 Planning Coordinator

5. Effective Date:

5.1 BAL-502-RF-03 shall become effective on the first day of the first calendar quarter that is after the date that this standard is approved by applicable regulatory authorities or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect.

B. Requirements and Measures

R1 The Planning Coordinator shall perform and document a Resource Adequacy analysis annually. The Resource Adequacy analysis shall *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*:

1.1 Calculate a planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year[1] analyzed (per R1.2) being equal to 0.1. (This is comparable to a "one day in 10 year" criterion).

1.1.1 The utilization of Direct Control Load Management or curtailment of Interruptible Demand shall not contribute to the loss of Load probability.

1.1.2 The planning reserve margin developed from R1.1 shall be expressed as a percentage of the median[2] forecast peak Net Internal Demand (planning reserve margin).

1.2 Be performed or verified separately for each of the following planning years:

[1] The annual period over which the LOLE is measured, and the resulting resource requirements are established (June 1st through the following May 31st).

[2] The median forecast is expected to have a 50% probability of being too high and 50% probability of being too low (50:50).

1.2.1 Perform an analysis for Year One.

1.2.2 Perform an analysis or verification at a minimum for one year in the 2 through 5 year period and at a minimum one year in the 6 though 10 year period.

1.2.2.1 If the analysis is verified, the verification must be supported by current or past studies for the same planning year.

1.3 Include the following subject matter and documentation of its use:

1.3.1 Load forecast characteristics:

1.3.1.1 Median (50:50) forecast peak Load.

1.3.1.2 Load forecast uncertainty (reflects variability in the Load forecast due to weather and regional economic forecasts).

1.3.1.3 Load diversity.

1.3.1.4 Seasonal Load variations.

1.3.1.5 Daily demand modeling assumptions (firm, interruptible).

1.3.1.6 Contractual arrangements concerning curtailable/Interruptible Demand.

1.3.2 Resource characteristics:

1.3.2.1 Historic resource performance and any projected changes

1.3.2.2 Seasonal resource ratings

1.3.2.3 Modeling assumptions of firm capacity purchases from and sales to entities outside the Planning Coordinator area.

1.3.2.4 Resource planned outage schedules, deratings, and retirements.

1.3.2.5 Modeling assumptions of intermittent and energy limited resource such as wind and cogeneration.

1.3.2.6 Criteria for including planned resource additions in the analysis

1.3.3 Transmission limitations that prevent the delivery of generation reserves

1.3.3.1 Criteria for including planned Transmission Facility additions in the analysis

1.3.4 Assistance from other interconnected systems including multi-area assessment considering Transmission limitations into the study area.

1.4 Consider the following resource availability characteristics and document how and why they were included in the analysis or why they were not included:

1.4.1 Availability and deliverability of fuel.

1.4.2 Common mode outages that affect resource availability

1.4.3 Environmental or regulatory restrictions of resource availability.

1.4.4 Any other demand (Load) response programs not included in R1.3.1.

1.4.5 Sensitivity to resource outage rates.

1.4.6 Impacts of extreme weather/drought conditions that affect unit availability.

1.4.7 Modeling assumptions for emergency operation procedures used to make reserves available.

1.4.8 Market resources not committed to serving Load (uncommitted resources) within the Planning Coordinator area.

1.5 Consider Transmission maintenance outage schedules and document how and why they were included in the Resource Adequacy analysis or why they were not included

1.6 Document that capacity resources are appropriately accounted for in its Resource Adequacy analysis

1.7 Document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis

M1 Each Planning Coordinator shall possess the documentation that a valid Resource Adequacy analysis was performed or verified in accordance with R1

R2 The Planning Coordinator shall annually document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*.

2.1 This documentation shall cover each of the years in Year One through ten.

2.2 This documentation shall include the Planning Reserve margin calculated per requirement R1.1 for each of the three years in the analysis.

2.3 The documentation as specified per requirement R2.1 and R2.2 shall be publicly posted no later than 30 calendar days prior to the beginning of Year One.

M2 Each Planning Coordinator shall possess the documentation of its projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis on an annual basis in accordance with R2.

R3 The Planning Coordinator shall identify any gaps between the needed amount of planning reserves defined in Requirement R1, Part 1.1 and the projected planning reserves documented in Requirement R2 *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*.

M3 Each Planning Coordinator shall possess the documentation identifying any gaps between the needed amounts of planning reserves and projected planning reserves in accordance with R3.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

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

The Applicable Entity shall keep data or evidence to show compliance with Requirements R1 through R3, and Measures M1 through M3 from the most current and prior two years.

If an Applicable Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

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

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit
Self-Certification
Spot Checking
Compliance Investigation
Self-Reporting
Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	VIOLATION SEVERITY LEVEL			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Medium	The Planning Coordinator Resource Adequacy analysis failed to consider 1 or 2 of the Resource availability characteristics subcomponents under Requirement R1, Part 1.4 and documentation of how and why they were included in the analysis or why they were not included **OR** The Planning Coordinator Resource Adequacy analysis failed to consider Transmission maintenance outage schedules and document how and why they were included in the analysis or why they were not included per Requirement R1, Part 1.5	The Planning Coordinator Resource Adequacy analysis failed to express the planning reserve margin developed from Requirement R1, Part 1.1 as a percentage of the net Median forecast peak Load per Requirement R1, Part 1.1.2 **OR** The Planning Coordinator Resource Adequacy analysis failed to include 1 of the Load forecast Characteristics subcomponents under Requirement R1, Part 1.3.1 and documentation of its use **OR**	The Planning Coordinator Resource Adequacy analysis failed to be performed or verified separately for individual years of Year One through Year Ten per Requirement R1, Part 1.2 **OR** The Planning Coordinator failed to perform an analysis or verification for one year in the 2 through 5 year period or one year in the 6 though 10 year period or both per Requirement R1, Part 1.2.2 **OR** The Planning Coordinator Resource Adequacy analysis failed to include 2 or	The Planning Coordinator failed to perform and document a Resource Adequacy analysis annually per R1. **OR** The Planning Coordinator Resource Adequacy analysis failed to calculate a Planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year analyzed for each planning period being equal to 0.1 per Requirement R1, Part 1.1 **OR**

				The Planning Coordinator Resource Adequacy analysis failed to include 1 of the Resource Characteristics subcomponents under Requirement R1, Part 1.3.2 and documentation of its use **Or** The Planning Coordinator Resource Adequacy analysis failed to document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis per Requirement R1, Part 1.7	more of the Load forecast Characteristics subcomponents under Requirement R1, Part 1.3.1 and documentation of their use **OR** The Planning Coordinator Resource Adequacy analysis failed to include 2 or more of the Resource Characteristics subcomponents under Requirement R1, Part 1.3.2 and documentation of their use **OR** The Planning Coordinator Resource Adequacy analysis failed to include Transmission limitations and documentation of its use	The Planning Coordinator failed to perform an analysis for Year One per Requirement R1, Part 1.2.1

					per Requirement R1, Part 1.3.3 **OR** The Planning Coordinator Resource Adequacy analysis failed to include assistance from other interconnected systems and documentation of its use per Requirement R1, Part 1.3.4 **OR** The Planning Coordinator Resource Adequacy analysis failed to consider 3 or more Resource availability characteristics subcomponents under Requirement R1, Part 1.4 and documentation of how and why they were included in the analysis or why they were not included	

					OR The Planning Coordinator Resource Adequacy analysis failed to document that capacity resources are appropriately accounted for in its Resource Adequacy analysis per Requirement R1, Part 1.6	
R2	Long-term Planning	Lower	The Planning Coordinator failed to publicly post the documents as specified per requirement Requirement R2, Part 2.1 and Requirement R2, Part 2.2 later than 30 calendar days prior to the beginning of Year One per Requirement R2, Part 2.3	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for one of the years in the 2 through 10 year period per Requirement R2, Part 2.1. **OR** The Planning Coordinator failed to document the Planning	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for year 1 of the 10 year period per Requirement R2, Part 2.1. **OR** The Planning Coordinator failed to document the projected Load and resource	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis per Requirement R2, Part 2.

				Reserve margin calculated per requirement R1.1 for each of the three years in the analysis per Requirement R2, Part 2.2.	capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for two or more of the years in the 2 through 10 year period per Requirement R2, Part 2.1.	
R3	Long-term Planning	Lower	None	None	None	The Planning Coordinator failed to identify any gaps between the needed amount of planning reserves and the projected planning reserves, per R3

D. Regional Variances

None

E. Interpretations

None

F. Associated Documents

None

Version History

Version	Date	Action	Change Tracking
BAL-502-RFC-02	12/04/08	ReliabilityFirst Board Approved	
BAL-502-RFC-02	08/05/09	NERC BoT Approved	
BAL-502-RFC-02	03/17/11	FERC Approved	

Draft Planning Resource Adequacy Analysis, Assessment and Documentation (BAL-502-RF-03) Implementation Plan

Requested Approvals

- None

Requested Retirements

- BAL-502-RFC-02

Prerequisite Approval

- None

Revisions to Defined Terms in the NERC Glossary

- None

Effective Date

- BAL-502-RF-03 shall become effective on the first day of the first calendar quarter that is after the date that this standard is approved by applicable regulatory authorities or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect.

ReliabilityFirst Reliability Standards Voting Process Recirculation Ballot Results

Planning Resource Adequacy Analysis, Assessment and Documentation (BAL-502-RF-03)

02/06/17 through 02/15/17

Total Affirmative: 27 Total Negative: 1 Total Abstentions: 0 Total Votes Cast: 28

Total Pool Members: 30

Quorum: 93%

Vote Result: **Pass**

Category	Affirmative	Negative	Abstentions	Pool Members	Votes Cast	Votes Counted	Approval	Result
Category 1	6	1	0	7	7	7	85.71 %	Pass
Category 2	5	0	0	6	5	5	100.00 %	Pass
Category 3	7	0	0	7	7	7	100.00 %	Pass
Category 4	3	0	0	4	3	3	100.00 %	Pass
Category 5	6	0	0	6	6	6	100.00 %	Pass

Category	Vote	Member	Entity
Category 1	Affirmative	James Anderson	Consumers Energy Company
	Negative	Scott Cunningham	Ohio Valley Electric Corporation
	Affirmative	Chris Scanlon	Baltimore Gas and Electric Company
	Affirmative	William J Smith	FirstEnergy Utilities
	Affirmative	Greg Milosek	ITC Transmission
	Affirmative	Brenda Lyn Truhe	PPL Electric Utilities Corporation
	Affirmative	Joseph A. Smith	Public Service Electric & Gas Company
Category 2	Affirmative	Jeff DePriest	DTE Electric
	Affirmative	David Greyerbiehl	Consumers Energy Company
	Affirmative	Ruth Miller	Exelon Generation Company, LLC
	Affirmative	Mark Koziel	FirstEnergy Utilities
	Affirmative	Scott Hoggatt	WEC Energy Group
	No Vote	Sean Bodikin	Dominion Energy
Category 3	Affirmative	John Bee	Commonwealth Edison Company

	Affirmative	Jeff Beattie	Consumers Energy Company
	Affirmative	Theresa Ciancio	FirstEnergy Utilities
	Affirmative	Bob Thomas	Illinois Municipal Electric Agency
	Affirmative	Joe O'Brien	Northern Indiana Public Service Company
	Affirmative	William Watson	Old Dominion Electric Cooperative
	Affirmative	Karla Jara	PSEG Energy Resources & Trade LLC
Category 4	Affirmative	Terry Bilke	MISO
	Affirmative	Mark Holman	PJM Interconnection
	No Vote	Karl Blaszowski	Consumers Energy Company
	Affirmative	Tony Jankowski	WEC Energy Group
Category 5	Affirmative	Karie L. Barczak	DTE Electric
	Affirmative	Douglas G Hohlbaugh	FirstEnergy Utilities
	Affirmative	Jeffrey C. Mueller	Public Service Electric & Gas Company
	Affirmative	Margaret Powell	PECO Energy Company
	Affirmative	Tom Breene	WEC Energy Group
	Affirmative	Julie Hegedus	Consumers Energy Company

A. Introduction

1. Title: **Planning Resource Adequacy Analysis, Assessment and Documentation**

2. Number: **BAL-502-RF-03**

3. Purpose: To establish common criteria, based on "one day in ten year" loss of Load expectation principles, for the analysis, assessment and documentation of Resource Adequacy for Load in the ReliabilityFirst Corporation (RF) region

4. Applicability

4.1 Functional Entities

4.1.1 Planning Coordinator

5. Effective Date:

5.1 BAL-502-RF-03 shall become effective on the first day of the first calendar quarter that is after the date that this standard is approved by applicable regulatory authorities or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect.

B. Requirements and Measures

R1 The Planning Coordinator shall perform and document a Resource Adequacy analysis annually. The Resource Adequacy analysis shall *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*:

1.1 Calculate a planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year[1] analyzed (per R1.2) being equal to 0.1. (This is comparable to a "one day in 10 year" criterion).

1.1.1 The utilization of Direct Control Load Management or curtailment of Interruptible Demand shall not contribute to the loss of Load probability.

1.1.2 The planning reserve margin developed from R1.1 shall be expressed as a percentage of the median[2] forecast peak Net Internal Demand (planning reserve margin).

1.2 Be performed or verified separately for each of the following planning years:

[1] The annual period over which the LOLE is measured, and the resulting resource requirements are established (June 1st through the following May 31st).

[2] The median forecast is expected to have a 50% probability of being too high and 50% probability of being too low (50:50).

1.2.1 Perform an analysis for Year One.

1.2.2 Perform an analysis or verification at a minimum for one year in the 2 through 5 year period and at a minimum one year in the 6 though 10 year period.

1.2.2.1 If the analysis is verified, the verification must be supported by current or past studies for the same planning year.

1.3 Include the following subject matter and documentation of its use:

1.3.1 Load forecast characteristics:

1.3.1.1 Median (50:50) forecast peak Load.

1.3.1.2 Load forecast uncertainty (reflects variability in the Load forecast due to weather and regional economic forecasts).

1.3.1.3 Load diversity.

1.3.1.4 Seasonal Load variations.

1.3.1.5 Daily demand modeling assumptions (firm, interruptible).

1.3.1.6 Contractual arrangements concerning curtailable/Interruptible Demand.

1.3.2 Resource characteristics:

1.3.2.1 Historic resource performance and any projected changes

1.3.2.2 Seasonal resource ratings

1.3.2.3 Modeling assumptions of firm capacity purchases from and sales to entities outside the Planning Coordinator area.

1.3.2.4 Resource planned outage schedules, deratings, and retirements.

1.3.2.5 Modeling assumptions of intermittent and energy limited resource such as wind and cogeneration.

1.3.2.6 Criteria for including planned resource additions in the analysis

1.3.3 Transmission limitations that prevent the delivery of generation reserves

1.3.3.1 Criteria for including planned Transmission Facility additions in the analysis

1.3.4 Assistance from other interconnected systems including multi-area assessment considering Transmission limitations into the study area.

1.4 Consider the following resource availability characteristics and document how and why they were included in the analysis or why they were not included:

1.4.1 Availability and deliverability of fuel.

1.4.2 Common mode outages that affect resource availability

1.4.3 Environmental or regulatory restrictions of resource availability.

1.4.4 Any other demand (Load) response programs not included in R1.3.1.

1.4.5 Sensitivity to resource outage rates.

1.4.6 Impacts of extreme weather/drought conditions that affect unit availability.

1.4.7 Modeling assumptions for emergency operation procedures used to make reserves available.

1.4.8 Market resources not committed to serving Load (uncommitted resources) within the Planning Coordinator area.

1.5 Consider Transmission maintenance outage schedules and document how and why they were included in the Resource Adequacy analysis or why they were not included

1.6 Document that capacity resources are appropriately accounted for in its Resource Adequacy analysis

1.7 Document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis

M1 Each Planning Coordinator shall possess the documentation that a valid Resource Adequacy analysis was performed or verified in accordance with R1

R2 The Planning Coordinator shall annually document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*.

2.1 This documentation shall cover each of the years in Year One through ten.

2.2 This documentation shall include the Planning Reserve margin calculated per requirement R1.1 for each of the three years in the analysis.

2.3 The documentation as specified per requirement R2.1 and R2.2 shall be publicly posted no later than 30 calendar days prior to the beginning of Year One.

M2 Each Planning Coordinator shall possess the documentation of its projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis on an annual basis in accordance with R2.

R3 The Planning Coordinator shall identify any gaps between the needed amount of planning reserves defined in Requirement R1, Part 1.1 and the projected planning reserves documented in Requirement R2 *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*.

M3 Each Planning Coordinator shall possess the documentation identifying any gaps between the needed amounts of planning reserves and projected planning reserves in accordance with R3.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

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

The Applicable Entity shall keep data or evidence to show compliance with Requirements R1 through R3, and Measures M1 through M3 from the most current and prior two years.

If an Applicable Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

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

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit
Self-Certification
Spot Checking
Compliance Investigation
Self-Reporting
Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	VIOLATION SEVERITY LEVEL			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Medium	The Planning Coordinator Resource Adequacy analysis failed to consider 1 or 2 of the Resource availability characteristics subcomponents under Requirement R1, Part 1.4 and documentation of how and why they were included in the analysis or why they were not included **OR** The Planning Coordinator Resource Adequacy analysis failed to consider Transmission maintenance outage schedules and document how and why they were included in the analysis or why they were not included per Requirement R1, Part 1.5	The Planning Coordinator Resource Adequacy analysis failed to express the planning reserve margin developed from Requirement R1, Part 1.1 as a percentage of the net Median forecast peak Load per Requirement R1, Part 1.1.2 **OR** The Planning Coordinator Resource Adequacy analysis failed to include 1 of the Load forecast Characteristics subcomponents under Requirement R1, Part 1.3.1 and documentation of its use **OR**	The Planning Coordinator Resource Adequacy analysis failed to be performed or verified separately for individual years of Year One through Year Ten per Requirement R1, Part 1.2 **OR** The Planning Coordinator failed to perform an analysis or verification for one year in the 2 through 5 year period or one year in the 6 though 10 year period or both per Requirement R1, Part 1.2.2 **OR** The Planning Coordinator Resource Adequacy analysis failed to include 2 or	The Planning Coordinator failed to perform and document a Resource Adequacy analysis annually per R1. **OR** The Planning Coordinator Resource Adequacy analysis failed to calculate a Planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year analyzed for each planning period being equal to 0.1 per Requirement R1, Part 1.1 **OR**

				The Planning Coordinator Resource Adequacy analysis failed to include 1 of the Resource Characteristics subcomponents under Requirement R1, Part 1.3.2 and documentation of its use **Or** The Planning Coordinator Resource Adequacy analysis failed to document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis per Requirement R1, Part 1.7	more of the Load forecast Characteristics subcomponents under Requirement R1, Part 1.3.1 and documentation of their use **OR** The Planning Coordinator Resource Adequacy analysis failed to include 2 or more of the Resource Characteristics subcomponents under Requirement R1, Part 1.3.2 and documentation of their use **OR** The Planning Coordinator Resource Adequacy analysis failed to include Transmission limitations and documentation of its use	The Planning Coordinator failed to perform an analysis for Year One per Requirement R1, Part 1.2.1

					per Requirement R1, Part 1.3.3 **OR** The Planning Coordinator Resource Adequacy analysis failed to include assistance from other interconnected systems and documentation of its use per Requirement R1, Part 1.3.4 **OR** The Planning Coordinator Resource Adequacy analysis failed to consider 3 or more Resource availability characteristics subcomponents under Requirement R1, Part 1.4 and documentation of how and why they were included in the analysis or why they were not included	

					OR The Planning Coordinator Resource Adequacy analysis failed to document that capacity resources are appropriately accounted for in its Resource Adequacy analysis per Requirement R1, Part 1.6	
R2	Long-term Planning	Lower	The Planning Coordinator failed to publicly post the documents as specified per requirement Requirement R2, Part 2.1 and Requirement R2, Part 2.2 later than 30 calendar days prior to the beginning of Year One per Requirement R2, Part 2.3	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for one of the years in the 2 through 10 year period per Requirement R2, Part 2.1. **OR** The Planning Coordinator failed to document the Planning	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for year 1 of the 10 year period per Requirement R2, Part 2.1. **OR** The Planning Coordinator failed to document the projected Load and resource	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis per Requirement R2, Part 2.

				Reserve margin calculated per requirement R1.1 for each of the three years in the analysis per Requirement R2, Part 2.2.	capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for two or more of the years in the 2 through 10 year period per Requirement R2, Part 2.1.	
R3	Long-term Planning	Lower	None	None	None	The Planning Coordinator failed to identify any gaps between the needed amount of planning reserves and the projected planning reserves, per R3

D. Regional Variances

None

E. Interpretations

None

F. Associated Documents

None

Version History

Version	Date	Action	Change Tracking
BAL-502-RFC-02	12/04/08	ReliabilityFirst Board Approved	
BAL-502-RFC-02	08/05/09	NERC BoT Approved	
BAL-502-RFC-02	03/17/11	FERC Approved	
BAL-502-RFC-03	06/01/17	ReliabilityFirst Board Approved	

Planning Resource Adequacy Analysis, Assessment and Documentation (BAL-502-RF-03) Implementation Plan

Requested Approvals

- None

Requested Retirements

- BAL-502-RFC-02

Prerequisite Approval

- None

Revisions to Defined Terms in the NERC Glossary

- None

Effective Date

- BAL-502-RF-03 shall become effective on the first day of the first calendar quarter that is after the date that this standard is approved by applicable regulatory authorities or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect.

A. Introduction

1. Title: **Planning Resource Adequacy Analysis, Assessment and Documentation**

2. Number: **BAL-502-RF-03**

3. Purpose: To establish common criteria, based on "one day in ten year" loss of Load expectation principles, for the analysis, assessment and documentation of Resource Adequacy for Load in the ReliabilityFirst Corporation (RF) region

4. Applicability

4.1 Functional Entities

4.1.1 Planning Coordinator

5. Effective Date:

5.1 BAL-502-RF-03 shall become effective on the first day of the first calendar quarter that is after the date that this standard is approved by applicable regulatory authorities or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect.

B. Requirements and Measures

R1 The Planning Coordinator shall perform and document a Resource Adequacy analysis annually. The Resource Adequacy analysis shall *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*:

1.1 Calculate a planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year[1] analyzed (per R1.2) being equal to 0.1. (This is comparable to a "one day in 10 year" criterion).

1.1.1 The utilization of Direct Control Load Management or curtailment of Interruptible Demand shall not contribute to the loss of Load probability.

1.1.2 The planning reserve margin developed from R1.1 shall be expressed as a percentage of the median[2] forecast peak Net Internal Demand (planning reserve margin).

1.2 Be performed or verified separately for each of the following planning years:

[1] The annual period over which the LOLE is measured, and the resulting resource requirements are established (June 1st through the following May 31st).

[2] The median forecast is expected to have a 50% probability of being too high and 50% probability of being too low (50:50).

1.2.1 Perform an analysis for Year One.

1.2.2 Perform an analysis or verification at a minimum for one year in the 2 through 5 year period and at a minimum one year in the 6 though 10 year period.

1.2.2.1 If the analysis is verified, the verification must be supported by current or past studies for the same planning year.

1.3 Include the following subject matter and documentation of its use:

1.3.1 Load forecast characteristics:

1.3.1.1 Median (50:50) forecast peak Load.

1.3.1.2 Load forecast uncertainty (reflects variability in the Load forecast due to weather and regional economic forecasts).

1.3.1.3 Load diversity.

1.3.1.4 Seasonal Load variations.

1.3.1.5 Daily demand modeling assumptions (firm, interruptible).

1.3.1.6 Contractual arrangements concerning curtailable/Interruptible Demand.

1.3.2 Resource characteristics:

1.3.2.1 Historic resource performance and any projected changes

1.3.2.2 Seasonal resource ratings

1.3.2.3 Modeling assumptions of firm capacity purchases from and sales to entities outside the Planning Coordinator area.

1.3.2.4 Resource planned outage schedules, deratings, and retirements.

1.3.2.5 Modeling assumptions of intermittent and energy limited resource such as wind and cogeneration.

1.3.2.6 Criteria for including planned resource additions in the analysis

1.3.3 Transmission limitations that prevent the delivery of generation reserves

1.3.3.1 Criteria for including planned Transmission Facility additions in the analysis

1.3.4 Assistance from other interconnected systems including multi-area assessment considering Transmission limitations into the study area.

1.4 Consider the following resource availability characteristics and document how and why they were included in the analysis or why they were not included:

1.4.1 Availability and deliverability of fuel.

1.4.2 Common mode outages that affect resource availability

1.4.3 Environmental or regulatory restrictions of resource availability.

1.4.4 Any other demand (Load) response programs not included in R1.3.1.

1.4.5 Sensitivity to resource outage rates.

1.4.6 Impacts of extreme weather/drought conditions that affect unit availability.

1.4.7 Modeling assumptions for emergency operation procedures used to make reserves available.

1.4.8 Market resources not committed to serving Load (uncommitted resources) within the Planning Coordinator area.

1.5 Consider Transmission maintenance outage schedules and document how and why they were included in the Resource Adequacy analysis or why they were not included

1.6 Document that capacity resources are appropriately accounted for in its Resource Adequacy analysis

1.7 Document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis

M1 Each Planning Coordinator shall possess the documentation that a valid Resource Adequacy analysis was performed or verified in accordance with R1

R2 The Planning Coordinator shall annually document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*.

2.1 This documentation shall cover each of the years in Year One through ten.

2.2 This documentation shall include the Planning Reserve margin calculated per requirement R1.1 for each of the three years in the analysis.

2.3 The documentation as specified per requirement R2.1 and R2.2 shall be publicly posted no later than 30 calendar days prior to the beginning of Year One.

M2 Each Planning Coordinator shall possess the documentation of its projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis on an annual basis in accordance with R2.

R3 The Planning Coordinator shall identify any gaps between the needed amount of planning reserves defined in Requirement R1, Part 1.1 and the projected planning reserves documented in Requirement R2 *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*.

M3 Each Planning Coordinator shall possess the documentation identifying any gaps between the needed amounts of planning reserves and projected planning reserves in accordance with R3.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

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

The Applicable Entity shall keep data or evidence to show compliance with Requirements R1 through R3, and Measures M1 through M3 from the most current and prior two years.

If an Applicable Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

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

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit
Self-Certification
Spot Checking
Compliance Investigation
Self-Reporting
Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	VIOLATION SEVERITY LEVEL			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Medium	The Planning Coordinator Resource Adequacy analysis failed to consider 1 or 2 of the Resource availability characteristics subcomponents under Requirement R1, Part 1.4 and documentation of how and why they were included in the analysis or why they were not included **OR** The Planning Coordinator Resource Adequacy analysis failed to consider Transmission maintenance outage schedules and document how and why they were included in the analysis or why they were not included per Requirement R1, Part 1.5	The Planning Coordinator Resource Adequacy analysis failed to express the planning reserve margin developed from Requirement R1, Part 1.1 as a percentage of the net Median forecast peak Load per Requirement R1, Part 1.1.2 **OR** The Planning Coordinator Resource Adequacy analysis failed to include 1 of the Load forecast Characteristics subcomponents under Requirement R1, Part 1.3.1 and documentation of its use **OR**	The Planning Coordinator Resource Adequacy analysis failed to be performed or verified separately for individual years of Year One through Year Ten per Requirement R1, Part 1.2 **OR** The Planning Coordinator failed to perform an analysis or verification for one year in the 2 through 5 year period or one year in the 6 though 10 year period or both per Requirement R1, Part 1.2.2 **OR** The Planning Coordinator Resource Adequacy analysis failed to include 2 or	The Planning Coordinator failed to perform and document a Resource Adequacy analysis annually per R1. **OR** The Planning Coordinator Resource Adequacy analysis failed to calculate a Planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year analyzed for each planning period being equal to 0.1 per Requirement R1, Part 1.1 **OR**

				The Planning Coordinator Resource Adequacy analysis failed to include 1 of the Resource Characteristics subcomponents under Requirement R1, Part 1.3.2 and documentation of its use **Or** The Planning Coordinator Resource Adequacy analysis failed to document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis per Requirement R1, Part 1.7	more of the Load forecast Characteristics subcomponents under Requirement R1, Part 1.3.1 and documentation of their use **OR** The Planning Coordinator Resource Adequacy analysis failed to include 2 or more of the Resource Characteristics subcomponents under Requirement R1, Part 1.3.2 and documentation of their use **OR** The Planning Coordinator Resource Adequacy analysis failed to include Transmission limitations and documentation of its use	The Planning Coordinator failed to perform an analysis for Year One per Requirement R1, Part 1.2.1

					per Requirement R1, Part 1.3.3 **OR** The Planning Coordinator Resource Adequacy analysis failed to include assistance from other interconnected systems and documentation of its use per Requirement R1, Part 1.3.4 **OR** The Planning Coordinator Resource Adequacy analysis failed to consider 3 or more Resource availability characteristics subcomponents under Requirement R1, Part 1.4 and documentation of how and why they were included in the analysis or why they were not included	

					OR The Planning Coordinator Resource Adequacy analysis failed to document that capacity resources are appropriately accounted for in its Resource Adequacy analysis per Requirement R1, Part 1.6	
R2	Long-term Planning	Lower	The Planning Coordinator failed to publicly post the documents as specified per requirement Requirement R2, Part 2.1 and Requirement R2, Part 2.2 later than 30 calendar days prior to the beginning of Year One per Requirement R2, Part 2.3	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for one of the years in the 2 through 10 year period per Requirement R2, Part 2.1. **OR** The Planning Coordinator failed to document the Planning	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for year 1 of the 10 year period per Requirement R2, Part 2.1. **OR** The Planning Coordinator failed to document the projected Load and resource	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis per Requirement R2, Part 2.

				Reserve margin calculated per requirement R1.1 for each of the three years in the analysis per Requirement R2, Part 2.2.	capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for two or more of the years in the 2 through 10 year period per Requirement R2, Part 2.1.	
R3	Long-term Planning	Lower	None	None	None	The Planning Coordinator failed to identify any gaps between the needed amount of planning reserves and the projected planning reserves, per R3

D. Regional Variances

None

E. Interpretations

None

F. Associated Documents

None

Version History

Version	Date	Action	Change Tracking
BAL-502-RFC-02	12/04/08	ReliabilityFirst Board Approved	
BAL-502-RFC-02	08/05/09	NERC BoT Approved	
BAL-502-RFC-02	03/17/11	FERC Approved	
BAL-502-RFC-03	06/01/17	ReliabilityFirst Board Approved	

Planning Resource Adequacy Analysis, Assessment and Documentation (BAL-502-RF-03) Implementation Plan

Requested Approvals

- None

Requested Retirements

- BAL-502-RFC-02

Prerequisite Approval

- None

Revisions to Defined Terms in the NERC Glossary

- None

Effective Date

- BAL-502-RF-03 shall become effective on the first day of the first calendar quarter that is after the date that this standard is approved by applicable regulatory authorities or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect.

A. Introduction

1. Title: **Planning Resource Adequacy Analysis, Assessment and Documentation**

2. Number: **BAL-502-RF-03**

3. Purpose: To establish common criteria, based on "one day in ten year" loss of Load expectation principles, for the analysis, assessment and documentation of Resource Adequacy for Load in the ReliabilityFirst Corporation (RF) region

4. Applicability

4.1 Functional Entities

4.1.1 Planning Coordinator

5. Effective Date:

5.1 BAL-502-RF-03 shall become effective on the first day of the first calendar quarter that is after the date that this standard is approved by applicable regulatory authorities or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect.

B. Requirements and Measures

R1 The Planning Coordinator shall perform and document a Resource Adequacy analysis annually. The Resource Adequacy analysis shall *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*:

1.1 Calculate a planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year[1] analyzed (per R1.2) being equal to 0.1. (This is comparable to a "one day in 10 year" criterion).

1.1.1 The utilization of Direct Control Load Management or curtailment of Interruptible Demand shall not contribute to the loss of Load probability.

1.1.2 The planning reserve margin developed from R1.1 shall be expressed as a percentage of the median[2] forecast peak Net Internal Demand (planning reserve margin).

1.2 Be performed or verified separately for each of the following planning years:

[1] The annual period over which the LOLE is measured, and the resulting resource requirements are established (June 1st through the following May 31st).

[2] The median forecast is expected to have a 50% probability of being too high and 50% probability of being too low (50:50).

1.2.1 Perform an analysis for Year One.

1.2.2 Perform an analysis or verification at a minimum for one year in the 2 through 5 year period and at a minimum one year in the 6 though 10 year period.

1.2.2.1 If the analysis is verified, the verification must be supported by current or past studies for the same planning year.

1.3 Include the following subject matter and documentation of its use:

1.3.1 Load forecast characteristics:

1.3.1.1 Median (50:50) forecast peak Load.

1.3.1.2 Load forecast uncertainty (reflects variability in the Load forecast due to weather and regional economic forecasts).

1.3.1.3 Load diversity.

1.3.1.4 Seasonal Load variations.

1.3.1.5 Daily demand modeling assumptions (firm, interruptible).

1.3.1.6 Contractual arrangements concerning curtailable/Interruptible Demand.

1.3.2 Resource characteristics:

1.3.2.1 Historic resource performance and any projected changes

1.3.2.2 Seasonal resource ratings

1.3.2.3 Modeling assumptions of firm capacity purchases from and sales to entities outside the Planning Coordinator area.

1.3.2.4 Resource planned outage schedules, deratings, and retirements.

1.3.2.5 Modeling assumptions of intermittent and energy limited resource such as wind and cogeneration.

1.3.2.6 Criteria for including planned resource additions in the analysis

1.3.3 Transmission limitations that prevent the delivery of generation reserves

1.3.3.1 Criteria for including planned Transmission Facility additions in the analysis

1.3.4 Assistance from other interconnected systems including multi-area assessment considering Transmission limitations into the study area.

1.4 Consider the following resource availability characteristics and document how and why they were included in the analysis or why they were not included:

1.4.1 Availability and deliverability of fuel.

1.4.2 Common mode outages that affect resource availability

1.4.3 Environmental or regulatory restrictions of resource availability.

1.4.4 Any other demand (Load) response programs not included in R1.3.1.

1.4.5 Sensitivity to resource outage rates.

1.4.6 Impacts of extreme weather/drought conditions that affect unit availability.

1.4.7 Modeling assumptions for emergency operation procedures used to make reserves available.

1.4.8 Market resources not committed to serving Load (uncommitted resources) within the Planning Coordinator area.

1.5 Consider Transmission maintenance outage schedules and document how and why they were included in the Resource Adequacy analysis or why they were not included

1.6 Document that capacity resources are appropriately accounted for in its Resource Adequacy analysis

1.7 Document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis

M1 Each Planning Coordinator shall possess the documentation that a valid Resource Adequacy analysis was performed or verified in accordance with R1

R2 The Planning Coordinator shall annually document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*.

2.1 This documentation shall cover each of the years in Year One through ten.

2.2 This documentation shall include the Planning Reserve margin calculated per requirement R1.1 for each of the three years in the analysis.

2.3 The documentation as specified per requirement R2.1 and R2.2 shall be publicly posted no later than 30 calendar days prior to the beginning of Year One.

M2 Each Planning Coordinator shall possess the documentation of its projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis on an annual basis in accordance with R2.

R3 The Planning Coordinator shall identify any gaps between the needed amount of planning reserves defined in Requirement R1, Part 1.1 and the projected planning reserves documented in Requirement R2 *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*.

M3 Each Planning Coordinator shall possess the documentation identifying any gaps between the needed amounts of planning reserves and projected planning reserves in accordance with R3.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

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

The Applicable Entity shall keep data or evidence to show compliance with Requirements R1 through R3, and Measures M1 through M3 from the most current and prior two years.

If an Applicable Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

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

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit
Self-Certification
Spot Checking
Compliance Investigation
Self-Reporting
Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	VIOLATION SEVERITY LEVEL			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Medium	The Planning Coordinator Resource Adequacy analysis failed to consider 1 or 2 of the Resource availability characteristics subcomponents under Requirement R1, Part 1.4 and documentation of how and why they were included in the analysis or why they were not included **OR** The Planning Coordinator Resource Adequacy analysis failed to consider Transmission maintenance outage schedules and document how and why they were included in the analysis or why they were not included per Requirement R1, Part 1.5	The Planning Coordinator Resource Adequacy analysis failed to express the planning reserve margin developed from Requirement R1, Part 1.1 as a percentage of the net Median forecast peak Load per Requirement R1, Part 1.1.2 **OR** The Planning Coordinator Resource Adequacy analysis failed to include 1 of the Load forecast Characteristics subcomponents under Requirement R1, Part 1.3.1 and documentation of its use **OR**	The Planning Coordinator Resource Adequacy analysis failed to be performed or verified separately for individual years of Year One through Year Ten per Requirement R1, Part 1.2 **OR** The Planning Coordinator failed to perform an analysis or verification for one year in the 2 through 5 year period or one year in the 6 though 10 year period or both per Requirement R1, Part 1.2.2 **OR** The Planning Coordinator Resource Adequacy analysis failed to include 2 or	The Planning Coordinator failed to perform and document a Resource Adequacy analysis annually per R1. **OR** The Planning Coordinator Resource Adequacy analysis failed to calculate a Planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year analyzed for each planning period being equal to 0.1 per Requirement R1, Part 1.1 **OR**

				The Planning Coordinator Resource Adequacy analysis failed to include 1 of the Resource Characteristics subcomponents under Requirement R1, Part 1.3.2 and documentation of its use **Or** The Planning Coordinator Resource Adequacy analysis failed to document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis per Requirement R1, Part 1.7	more of the Load forecast Characteristics subcomponents under Requirement R1, Part 1.3.1 and documentation of their use **OR** The Planning Coordinator Resource Adequacy analysis failed to include 2 or more of the Resource Characteristics subcomponents under Requirement R1, Part 1.3.2 and documentation of their use **OR** The Planning Coordinator Resource Adequacy analysis failed to include Transmission limitations and documentation of its use	The Planning Coordinator failed to perform an analysis for Year One per Requirement R1, Part 1.2.1

					per Requirement R1, Part 1.3.3 **OR** The Planning Coordinator Resource Adequacy analysis failed to include assistance from other interconnected systems and documentation of its use per Requirement R1, Part 1.3.4 **OR** The Planning Coordinator Resource Adequacy analysis failed to consider 3 or more Resource availability characteristics subcomponents under Requirement R1, Part 1.4 and documentation of how and why they were included in the analysis or why they were not included	

					OR The Planning Coordinator Resource Adequacy analysis failed to document that capacity resources are appropriately accounted for in its Resource Adequacy analysis per Requirement R1, Part 1.6	
R2	Long-term Planning	Lower	The Planning Coordinator failed to publicly post the documents as specified per requirement Requirement R2, Part 2.1 and Requirement R2, Part 2.2 later than 30 calendar days prior to the beginning of Year One per Requirement R2, Part 2.3	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for one of the years in the 2 through 10 year period per Requirement R2, Part 2.1. **OR** The Planning Coordinator failed to document the Planning	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for year 1 of the 10 year period per Requirement R2, Part 2.1. **OR** The Planning Coordinator failed to document the projected Load and resource	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis per Requirement R2, Part 2.

				Reserve margin calculated per requirement R1.1 for each of the three years in the analysis per Requirement R2, Part 2.2.	capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for two or more of the years in the 2 through 10 year period per Requirement R2, Part 2.1.	
R3	Long-term Planning	Lower	None	None	None	The Planning Coordinator failed to identify any gaps between the needed amount of planning reserves and the projected planning reserves, per R3

D. Regional Variances

None

E. Interpretations

None

F. Associated Documents

None

Version History

Version	Date	Action	Change Tracking
BAL-502-RFC-02	12/04/08	ReliabilityFirst Board Approved	
BAL-502-RFC-02	08/05/09	NERC BoT Approved	
BAL-502-RFC-02	03/17/11	FERC Approved	

A. Introduction

1. Title: **Planning Resource Adequacy Analysis, Assessment and Documentation**

2. Number: **BAL-502-~~RFC-02~~RF-03**

~~3.~~ Purpose:

3. To establish common criteria, based on "one day in ten year" loss of Load expectation principles, for the analysis, assessment and documentation of Resource Adequacy for Load in the ReliabilityFirst Corporation (~~RFC~~RF) region

4. Applicability

4.1 Functional Entities

~~4.1~~4.1.1 Planning Coordinator

5. Effective Date:

~~**5.1** Upon RFC Board approval~~

5.1 BAL-502-RF-03 shall become effective on the first day of the first calendar quarter that is after the date that this standard is approved by applicable regulatory authorities or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect.

B. Requirements and Measures

R1 The Planning Coordinator shall perform and document a Resource Adequacy analysis annually. The Resource Adequacy analysis shall *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*:

~~R1~~1.1 Calculate a planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year[1] analyzed (per R1.2) being equal to 0.1. (This is comparable to a "one day in 10 year" criterion).

~~R1~~1.1.1 The utilization of Direct Control Load Management or curtailment of Interruptible Demand shall not contribute to the loss of Load probability.

[1] The annual period over which the LOLE is measured, and the resulting resource requirements are established (June 1st through the following May 31st).

~~R1~~1.1.2 The planning reserve margin developed from R1.1 shall be expressed as a percentage of the median[2] forecast peak Net Internal Demand (planning reserve margin).

~~R1~~1.2 Be performed or verified separately for each of the following planning years:

~~R1~~1.2.1 Perform an analysis for Year One.

~~R1~~1.2.2 Perform an analysis or verification at a minimum for one year in the 2 through 5 year period and at a minimum one year in the 6 though 10 year period.

~~R1~~1.2.2.1 If the analysis is verified, the verification must be supported by current or past studies for the same planning year.

~~R1~~1.3 Include the following subject matter and documentation of its use:

~~R1~~1.3.1 Load forecast characteristics:

- 1.3.1.1 Median (50:50) forecast peak Load.
- 1.3.1.2 Load forecast uncertainty (reflects variability in the Load forecast due to weather and regional economic forecasts).
- 1.3.1.3 Load diversity.
- 1.3.1.4 Seasonal Load variations.
- 1.3.1.5 Daily demand modeling assumptions (firm, interruptible).
- 1.3.1.6 Contractual arrangements concerning curtailable/Interruptible Demand.

~~R1~~1.3.2 Resource characteristics:

- 1.3.2.1 Historic resource performance and any projected changes
- 1.3.2.2 Seasonal resource ratings

[2] The median forecast is expected to have a 50% probability of being too high and 50% probability of being too low (50:50).

- 1.3.2.3 Modeling assumptions of firm capacity purchases from and sales to entities outside the Planning Coordinator area.
- 1.3.2.4 Resource planned outage schedules, deratings, and retirements.
- 1.3.2.5 Modeling assumptions of intermittent and energy limited resource such as wind and cogeneration.
- 1.3.2.6 Criteria for including planned resource additions in the analysis

~~R1~~1.3.3 Transmission limitations that prevent the delivery of generation reserves

~~R1~~1.3.3.1 Criteria for including planned Transmission Facility additions in the analysis

~~R1~~1.3.4 Assistance from other interconnected systems including multi-area assessment considering Transmission limitations into the study area.

~~R1~~1.4 Consider the following resource availability characteristics and document how and why they were included in the analysis or why they were not included:

- 1.4.1 Availability and deliverability of fuel.
- 1.4.2 Common mode outages that affect resource availability
- 1.4.3 Environmental or regulatory restrictions of resource availability.
- 1.4.4 Any other demand (Load) response programs not included in R1.3.1.
- 1.4.5 Sensitivity to resource outage rates.
- 1.4.6 Impacts of extreme weather/drought conditions that affect unit availability.
- 1.4.7 Modeling assumptions for emergency operation procedures used to make reserves available.
- 1.4.8 Market resources not committed to serving Load (uncommitted resources) within the Planning Coordinator area.

~~R1~~1.5 Consider Transmission maintenance outage schedules and document how and why they were included in the Resource Adequacy analysis or why they were not included

~~R1~~1.6 Document that capacity resources are appropriately accounted for in its Resource Adequacy analysis

~~R1~~1.7 Document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis

M1 Each Planning Coordinator shall possess the documentation that a valid Resource Adequacy analysis was performed or verified in accordance with R1

R2 The Planning Coordinator shall annually document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*.

~~R2~~2.1 This documentation shall cover each of the years in Year One through ten.

~~R2~~2.2 This documentation shall include the Planning Reserve margin calculated per requirement R1.1 for each of the three years in the analysis.

~~R2~~2.3 The documentation as specified per requirement R2.1 and R2.2 shall be publicly posted no later than 30 calendar days prior to the beginning of Year One.

~~C. Measures~~

~~**M1** Each Planning Coordinator shall possess the documentation that a valid Resource Adequacy analysis was performed or verified in accordance with R1~~

M2 Each Planning Coordinator shall possess the documentation of its projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis on an annual basis in accordance with R2.

R3 The Planning Coordinator shall identify any gaps between the needed amount of planning reserves defined in Requirement R1, Part 1.1 and the projected planning reserves documented in Requirement R2 *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*.

M3 Each Planning Coordinator shall possess the documentation identifying any gaps between the needed amounts of planning reserves and projected planning reserves in accordance with R3.

~~D.~~C. Compliance

1. Compliance Monitoring Process

1.1. Compliance ~~Monitoring Responsibility~~Enforcement Authority

~~Compliance Monitor - Reliability~~*~~First~~* ~~Corporation~~

~~1.2. Compliance Monitoring Period and Reset Timeframe~~

~~One calendar year~~

~~Data~~As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

~~1.3.~~1.2. Evidence Retention

~~The Planning Coordinator shall retain information from the most current and prior two years.~~

~~The Compliance Monitor shall retain any audit data for five years.~~

~~2. Violation Severity Levels~~

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

The Applicable Entity shall keep data or evidence to show compliance with Requirements R1 through R3, and Measures M1 through M3 from the most current and prior two years.

If an Applicable Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

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

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit
Self-Certification
Spot Checking
Compliance Investigation
Self-Reporting
Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

~~Req. Number~~ R #	Time Horizon	VRF	VIOLATION SEVERITY LEVEL			
	~~LOWER~~	~~MODERATE~~	~~HIGH~~Lower VSL	~~SEVERE~~Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Medium	The Planning Coordinator Resource Adequacy analysis failed to consider 1 or 2 of the Resource availability characteristics subcomponents under ~~R1~~Requirement R1, Part 1.4 and documentation of how and why they were included in the analysis or why they were not included **OR** The Planning Coordinator Resource Adequacy analysis failed to consider Transmission maintenance outage schedules and document how and why they were included in the analysis or why they were not included per ~~R1~~Requirement R1, Part 1.5	The Planning Coordinator Resource Adequacy analysis failed to express the planning reserve margin developed from Requirement R1, Part 1.1 as a percentage of the net Median forecast peak Load per ~~R1~~Requirement R1, Part 1.1.2 **OR** The Planning Coordinator Resource Adequacy analysis failed to include 1 of the Load forecast Characteristics subcomponents under ~~R1~~Requirement R1, Part 1.3.1 and documentation of its use **OR**	The Planning Coordinator Resource Adequacy analysis failed to be performed or verified separately for individual years of Year One through Year Ten per ~~R1~~Requirement R1, Part 1.2 **OR** The Planning Coordinator failed to perform an analysis or verification for one year in the 2 through 5 year period or one year in the 6 though 10 year period or both per Requirement R1, Part 1.2.2 **OR** The Planning Coordinator Resource Adequacy analysis	The Planning Coordinator failed to perform and document a Resource Adequacy analysis annually per R1. **OR** The Planning Coordinator Resource Adequacy analysis failed to calculate a Planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year analyzed for each planning period being equal to 0.1 per ~~R1~~Requirement R1, Part 1.1 **OR**

				The Planning Coordinator Resource Adequacy analysis failed to include 1 of the Resource Characteristics subcomponents under ~~R1~~Requirement R1, Part 1.3.2 and documentation of its use **Or** The Planning Coordinator Resource Adequacy analysis failed to document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis per ~~R1~~Requirement R1, Part 1.7	failed to include 2 or more of the Load forecast Characteristics subcomponents under ~~R1~~Requirement R1, Part 1.3.1 and documentation of their use **OR** The Planning Coordinator Resource Adequacy analysis failed to include 2 or more of the Resource Characteristics subcomponents under ~~R1~~Requirement R1, Part 1.3.2 and documentation of their use **OR** The Planning Coordinator Resource Adequacy analysis failed to include Transmission limitations and documentation of its use	The Planning Coordinator failed to perform an analysis for Year One per ~~R1~~Requirement R1, Part 1.2.1

					per ~~R1~~Requirement R1, Part 1.3.3 **OR** The Planning Coordinator Resource Adequacy analysis failed to include assistance from other interconnected systems and documentation of its use per ~~R1~~Requirement R1, Part 1.3.4 **OR** The Planning Coordinator Resource Adequacy analysis failed to consider 3 or more Resource availability characteristics subcomponents under ~~R1~~Requirement R1, Part 1.4 and documentation of how and why they were included in the analysis	

					or why they were not included **OR** The Planning Coordinator Resource Adequacy analysis failed to document that capacity resources are appropriately accounted for in its Resource Adequacy analysis per Requirement R1, Part 1.6	
R2	Long-term Planning	Lower	The Planning Coordinator failed to publicly post the documents as specified per requirement ~~R2~~Requirement R2, Part 2.1 and Requirement R2, Part 2.2 later than 30 calendar days prior to the beginning of Year One per ~~R2~~Requirement R2, Part 2.3	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for one of the years in the 2 through 10 year period per ~~R2~~Requirement R2, Part 2.1. **OR**	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for year 1 of the 10 year period per ~~R2~~Requirement R2, Part 2.1. **OR**	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis per Requirement R2, Part 2.

				The Planning Coordinator failed to document the Planning Reserve margin calculated per requirement R1.1 for each of the three years in the analysis per ~~R2~~Requirement R2, Part 2.2.	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for two or more of the years in the 2 through 10 year period per Requirement R2, Part 2.1.	
R3	Long-term Planning	Lower	None	None	None	The Planning Coordinator failed to identify any gaps between the needed amount of planning reserves and the projected planning reserves, per R3

~~**Definitions:**~~

~~**Resource Adequacy** - the ability of supply-side and demand-side resources to meet the aggregate electrical demand (including losses).~~

~~**Net Internal Demand** - Total of all end-use customer demand and electric system losses within specified metered boundaries, less Direct Control Load Management and Interruptible Demand.~~

~~**Peak Period** - A period consisting of two (2) or more calendar months but less than seven (7) calendar months, which includes the period during which the responsible entity's annual peak demand is expected to occur~~

Year One - The planning year that begins with the upcoming annual Peak Period.

The following definitions were extracted from the February 12th, 2008 NERC Glossary of Terms:

Direct Control Load Management - Demand-Side Management that is under the direct control of the system operator. DCLM may control the electric supply to individual appliances or equipment on customer premises. DCLM as defined here does not include Interruptible Demand.

Facility - 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.)

Interruptible Demand - Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment.

Load - An end-use device or customer that receives power from the electric system.

Transmission - An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.

D. Regional Variances

None

E. Interpretations

None

F. Associated Documents

None

Version History

Version	Date	Action	Change Tracking
BAL-502-RFC-02 ~~1st Draft~~	~~06/24/08 Through 07/23~~12/04/08	ReliabilityFirst Board Approved~~Posted for 1st Comment Period~~	
BAL-502-RFC-02 ~~2nd Draft~~	08/~~18/08 Through~~ 05/09/~~16/08~~	~~Posted for 2nd Comment Period~~NERC BoT Approved	
BAL-502-RFC-02 ~~3rd Draft~~	~~10/16/08 Through 10/30/08~~03/17/11	~~Posted for 15-Day Category Ballot~~FERC Approved	
~~BAL-502-RFC-02 3rd Draft~~	~~12/04/08~~	~~ReliabilityFirst Board Approved~~	

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

ReliabilityFirst Corporation
BAL-502-RF-03

Comment period open through June 12, 2017

Now Available

The ReliabilityFirst Corporation (RF) has requested NERC to post Regional Reliability Standard **BAL-502-RF-03 – Planning Resource Adequacy Analysis, Assessment and Documentation** for industry review and comment as permitted by the NERC Rules of Procedure.

Commenting
Use the electronic form to submit comments. If you experience any difficulties in using the electronic form, contact Mat Bunch. The form must be submitted by **8 p.m. Eastern, Monday, June 12, 2017.** An unofficial Word version of the comment form is posted on the Regional Reliability Standards Under Development page.

Regional Reliability Standards Development Process
Section 300 of NERC's Rules of Procedures of the Electric Reliability Organization governs the regional reliability standards development process.

Background
The main purpose of the drafting effort was to revise the existing FERC approved ReliabilityFirst Planning Resource Adequacy Analysis, Assessment and Documentation (BAL-502-RFC-02) Standard to address two FERC Directives as noted in FERC Order No 747 (FERC Order initially approving the Standard). The two FERC directives include (1) add time horizons to the two main requirements, and (2) consider modifying the regional Reliability Standard to include a requirement that the planning coordinators identify any gap between the needed amount of planning reserves defined in Requirement R1.1 and the planning reserves determined from the resource adequacy analysis. The Standard Drafting Team also made miscellaneous non-substantive formatting changes to better align with the format of NERC Reliability Standards.

Although the technical aspects of this Regional Reliability Standard have been vetted through RF's Regional Standards development process, the final approval process for a Regional Reliability Standard requires NERC publicly to notice and request comment on the criteria outlined in the comment form.

Documents and information about this project are available on the ReliabilityFirst's Standards Under Development page.

For more information or assistance, contact Standards Developer, Mat Bunch (via email) or at (404) 446-9785.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Unofficial Comment Form

Regional Reliability Standard
BAL-502-RF-03

DO NOT use this form for submitting comments. Use the electronic form to submit comments on the proposed modifications to the Regional Reliability Standard **BAL-502-RF-03 Planning Resource Adequacy Analysis, Assessment and Documentation**. The electronic form must be submitted by **8 p.m. Eastern, Monday, June 12, 2017.**

Documents and information about this project are available on the Reliability First's Standards Under Development page. If you have questions, contact Standards Developer, Mat Bunch (via email) or at (404) 446-9785.

Background Information

The main purpose of the drafting effort was to revise the existing FERC approved ReliabilityFirst Planning Resource Adequacy Analysis, Assessment and Documentation (BAL-502-RFC-02) Standard to address two FERC Directives as noted in (FERC Order initially approving the Standard). The two FERC directives include (1) add time horizons to the two main requirements, and (2) consider modifying the regional Reliability Standard to include a requirement that the planning coordinators identify any gap between the needed amount of planning reserves defined in Requirement R1.1 and the planning reserves determined from the resource adequacy analysis. The Standard Drafting Team also made miscellaneous non-substantive formatting changes to better align with the format of NERC Reliability Standards.

NERC Criteria for Developing or Modifying a Regional Reliability Standard

Regional Reliability Standard shall be: (1) a regional reliability standard that is more stringent than the continent-wide reliability standard, including a regional standard that addresses matters that the continent-wide reliability standard does not; or (2) a regional reliability standard that is necessitated by a physical difference in the bulk power system. Regional reliability standards shall provide for as much uniformity as possible with reliability standards across the interconnected bulk power system of the North American continent. Regional reliability standards, when approved by FERC and applicable authorities in Mexico and Canada, shall be made part of the body of NERC reliability standards and shall be enforced upon all applicable bulk power system owners, operators, and users within the applicable area, regardless of membership in the region.

The approval process for a regional reliability standard requires NERC to publicly notice and request comment on the proposed standard. Comments shall be permitted only on the following criteria (technical aspects of the standard are vetted through the regional standards development process):

> **Open** — Regional reliability standards shall provide that any person or entity that is directly and materially affected by the reliability of the bulk power system within the regional entity shall be

able to participate in the development and approval of reliability standards. There shall be no undue financial barriers to participation. Participation shall not be conditional upon membership in the regional entity, a regional entity or any organization, and shall not be unreasonably restricted on the basis of technical qualifications or other such requirements.

Inclusive — Regional reliability standards shall provide that any person with a direct and material interest has a right to participate by expressing an opinion and its basis, having that position considered, and appealing through an established appeals process, if adversely affected.

Balanced — Regional reliability standards shall have a balance of interests and shall not be dominated by any two-interest categories and no single-interest category shall be able to defeat a matter.

Due Process — Regional reliability standards shall provide for reasonable notice and opportunity for public comment. At a minimum, the standard shall include public notice of the intent to develop a standard, a public comment period on the proposed standard, due consideration of those public comments, and a ballot of interested stakeholders.

Transparent — All actions material to the development of regional reliability standards shall be transparent. All standards development meetings shall be open and publicly noticed on the regional entity's Web site.

Review the revised BAL-502-RF-03 regional standard and answer the following questions.

1. Do you agree the development of BAL-502-RF-03 met the "Open" criteria as outlined above? If "No", please explain in the comment area below.

   ☐ Yes
   ☐ No
   Comments:

2. Do you agree the development of BAL-502-RF-03 met the "Inclusive" criteria as outlined above? If "No", please explain in the comment area below.

   ☐ Yes
   ☐ No
   Comments:

3. Do you agree the development of BAL-502-RF-03 met the "Balanced" criteria as outlined above? If "No", please explain in the comment area below.

   ☐ Yes
   ☐ No
   Comments:

4. Do you agree the development of BAL-502-RF-03 met the “Due Process” criteria as outlined above? If “No”, please explain in the comment area below.

   ☐ Yes
   ☐ No
   Comments:

5. Do you agree the development of BAL-502-RF-03 met the “Transparent” criteria as outlined above? If “No”, please explain in the comment area below.

   ☐ Yes
   ☐ No
   Comments:

Comment Report

Project Name:	Regional Reliability Standard (Reliability First) | BAL-502-RF-03
Comment Period Start Date:	4/28/2017
Comment Period End Date:	6/12/2017
Associated Ballots:	

There were 2 sets of responses, including comments from approximately 2 different people from approximately 2 companies representing 5 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree the development of BAL-502-RF-03 met the “Open” criteria as outlined above? If “No”, please explain in the comment area below.

2. Do you agree the development of BAL-502-RF-03 met the “Inclusive” criteria as outlined above? If “No”, please explain in the comment area below.

3. Do you agree the development of BAL-502-RF-03 met the “Balanced” criteria as outlined above? If “No”, please explain in the comment area below.

4. Do you agree the development of BAL-502-RF-03 met the “Due Process” criteria as outlined above? If “No”, please explain in the comment area below.

5. Do you agree the development of BAL-502-RF-03 met the “Transparent” criteria as outlined above? If “No”, please explain in the comment area below.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region

1. Do you agree the development of BAL-502-RF-03 met the “Open” criteria as outlined above? If “No”, please explain in the comment area below.	
Chris Scanlon - Exelon - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Candace Morakinyo - WEC Energy Group, Inc. - 3,4,5,6 - MRO,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

2. Do you agree the development of BAL-502-RF-03 met the “Inclusive” criteria as outlined above? If “No”, please explain in the comment area below.	
Candace Morakinyo - WEC Energy Group, Inc. - 3,4,5,6 - MRO,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Scanlon - Exelon - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

3. Do you agree the development of BAL-502-RF-03 met the “Balanced” criteria as outlined above? If “No”, please explain in the comment area below.	
Chris Scanlon - Exelon - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Candace Morakinyo - WEC Energy Group, Inc. - 3,4,5,6 - MRO,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

4. Do you agree the development of BAL-502-RF-03 met the “Due Process” criteria as outlined above? If “No”, please explain in the comment area below.	
Candace Morakinyo - WEC Energy Group, Inc. - 3,4,5,6 - MRO,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Scanlon - Exelon - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

5. Do you agree the development of BAL-502-RF-03 met the “Transparent” criteria as outlined above? If “No”, please explain in the comment area below.

Chris Scanlon - Exelon - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Candace Morakinyo - WEC Energy Group, Inc. - 3,4,5,6 - MRO,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Exhibit E

Planning Resource Adequacy, Analysis, Assessment and Documentation Standard Drafting Team Roster

Planning Resource Adequacy Analysis, Assessment and Documentation (PRAA)
Standard Drafting Team Roster (06/15/16)

Contact	Company	Email	Phone
Joe O'Brien	NIPSCO	jnobrien@nisource.com	219-853-5470
Jeffery W. Beattie	Consumers Energy	jwbeattie@cmsenergy.com	517-788-7220
Tom Falin	PJM	thomas.falin@pjm.com	610-666-4683
Jordan Cole	MISO	jcole@misoenergy.org	651-632-8573
Anthony Jablonski	ReliabilityFirst Staff	anthony.jablonski@rfirst.org	216-503-0693

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

September 5, 2017

VIA ELECTRONIC FILING

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C. 20426

RE: Informational Filing regarding Reliability Standard PRC-006-3 (*Automatic Underfrequency Load Shedding*)

Dear Ms. Bose:

The North American Electric Reliability Corporation ("NERC") hereby provides notice to the Federal Energy Regulatory Commission ("FERC") regarding Reliability Standard PRC-006-3 (*Automatic Underfrequency Load Shedding*). Reliability Standard PRC-006-3 revises the regional Variance for the Québec Interconnection as necessary to account for the physical characteristics and operational practices of that Interconnection. No changes have been made to any of the continent-wide Requirements of Commission-approved Reliability Standard PRC-006-2[1] nor the regional Variance for the Western Electricity Coordinating Council ("WECC") Interconnection.

The standard, which was developed in accordance with the NERC Rules of Procedure through the Northeast Power Coordinating Council ("NPCC") standard development process, was adopted by the NPCC Board of Trustees on May 3, 2017 and by the NERC Board of Trustees on August 10, 2017. The standard has been submitted for the approval of the Regie d'lenergie of the Province of Québec.[2]

As NERC proposes no changes to any standard Requirement or compliance element that is mandatory and enforceable within the United States, NERC does not seek approval of Reliability Standard PRC-006-3. To maintain consistency in standard versions approved by the NERC Board of Trustees and used throughout North America, however, NERC will transition all U.S.-based entities to Reliability

[1] The Commission approved Reliability Standard PRC-006-2 on March 4, 2015. *See N. Am. Elec. Reliability Corp.*, Docket No. RD15-2-000 (Mar. 4, 2015) (delegated letter order).

[2] *Notice of Filing of the North American Electric Reliability Corporation of Proposed Reliability Standard PRC-006-3 (Québec Variance)*, (filed Sept. 5, 2017) *available at* http://www.nerc.com/FilingsOrders/ca/Canadian%20Filings%20and%20Orders%20DL/PRC-006-3%20Quebec%20Variance%20Petition%20(Quebec).pdf.

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Standard PRC-006-3 effective October 1, 2017 in accordance with the Effective Date provision contained in the standard. Reliability Standard PRC-006-2 shall be retired immediately prior to the effective date of PRC-006-3.

NERC provides notice of PRC-006-3 for informational purposes only.

Respectfully submitted,

/s/ Lauren A. Perotti

Shamai Elstein
Senior Counsel
Lauren A. Perotti
Counsel
North American Electric Reliability Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 400-3000
shamai.elstein@nerc.net
lauren.perotti@nerc.net

Counsel for North American Electric Reliability Corporation

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. _____**

JOINT PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION AND SERC RELIABILITY CORPORATION FOR APPROVAL OF PROPOSED REGIONAL RELIABILITY STANDARD PRC-006-SERC-02

Holly A. Hawkins
General Counsel
Rebecca Poulsen
Legal Counsel
SERC Reliability Corporation
3701 Arco Corporate Drive, Suite 300
Charlotte, NC 28273
(704) 414-5238
hhawkins@serc1.org
rpoulsen@serc1.org

Counsel for the SERC Reliability Corporation

Shamai Elstein
Senior Counsel
Marisa Hecht
Counsel
North American Electric Reliability Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 400-3000
shamai.elstein@nerc.net
marisa.hecht@nerc.net

Counsel for the North American Electric Reliability Corporation

September 8, 2017

TABLE OF CONTENTS

I. EXECUTIVE SUMMARY 2

II. NOTICES AND COMMUNICATIONS ..... **Error! Bookmark not defined.**

III. BACKGROUND ..... **Error! Bookmark not defined.**

A. Regulatory Framework 4

B. SERC Regional Reliability Standards Development Process 5

C. The Development History of Proposed PRC-006-SERC-02 6

IV. JUSTIFICATION FOR APPROVAL 6

A. Justification for the Need for the Proposed Regional Reliability Standard 8

B. Description and Technical Basis of Proposed Revisions 8

C. Enforceability of Proposed Regional Reliability Standard PRC-006-SERC-02 10

V. EFFECTIVE DATE 10

VI. CONCLUSION 11

Exhibit A Proposed Regional Reliability Standard, PRC-006-SERC-02 – Automatic Underfrequency Load Shedding Requirements and Effective Date

Exhibit B Order No. 672 Criteria for Proposed Regional Reliability Standard PRC-006-SERC-02

Exhibit C Summary of Development History and Complete Record of Development

Exhibit D SERC Engineering Committee Dynamics Review Subcommittee Roster

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. _____**

JOINT PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION AND SERC RELIABILITY CORPORATION FOR APPROVAL OF PROPOSED REGIONAL RELIABILITY STANDARD PRC-006-SERC-02

Pursuant to Section 215(d)(1) of the Federal Power Act ("FPA")[1] and Section 39.5[2] of the Federal Energy Regulatory Commission's ("FERC" or "Commission") regulations, the North American Electric Reliability Corporation ("NERC")[3] and the SERC Reliability Corporation ("SERC") hereby submit proposed regional Reliability Standard PRC-006-SERC-02 – Automatic Underfrequency Load Shedding ("UFLS") Requirements for Commission approval. Proposed regional Reliability Standard PRC-006-SERC-02 establishes consistent and coordinated requirements for the design, implementation, and analysis of automatic UFLS programs among all SERC applicable entities.

NERC requests that the Commission approve proposed regional Reliability Standard PRC-006-SERC-02 (**Exhibit A**) as just, reasonable, not unduly discriminatory or preferential, and in the public interest.[4] NERC also requests approval of: (i) the Effective Date (**Exhibit A**) for the proposed regional Reliability Standard; (ii) the associated Violation Risk Factors ("VRFs") and

---

1 16 U.S.C. § 824o (2012).

2 18 C.F.R. § 39.5 (2017).

3 The Commission certified NERC as the electric reliability organization ("ERO") in accordance with Section 215 of the FPA on July 20, 2006. *N. Am. Elec. Reliability Corp.*, 116 FERC ¶ 61,062 (2006) ("ERO Certification Order").

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

Violation Severity Levels ("VSLs") (**Exhibits A and B**); and (iii) the retirement of regional Reliability Standard PRC-006-SERC-01. The NERC Board of Trustees adopted proposed regional Reliability Standard PRC-006-SERC-02 on August 10, 2017.

As required by Section 39.5(a)[5] of the Commission's regulations, this petition presents the technical basis and purpose of proposed regional Reliability Standard PRC-006-SERC-02; a demonstration that the proposed regional Reliability Standard meets the criteria identified by the Commission in Order No. 672[6] (**Exhibit B**); and a summary of the development history (**Exhibit C**).

I. EXECUTIVE SUMMARY

Proposed regional Reliability Standard PRC-006-SERC-02 incorporates revisions that provide additional flexibility for Planning Coordinators to select the peak season for UFLS plans and additional clarity on the load that can be used for UFLS schemes in the SERC region. The proposed revisions resulted from a periodic review of PRC-006-SERC-01.

The purpose of proposed regional Reliability Standard PRC-006-SERC-02 is to establish consistent and coordinated requirements for the design, implementation, and analysis of automatic UFLS programs among all SERC applicable entities. The requirements address the following: (1) identifying a Planning Coordinator's subregion as an island; (2) developing a UFLS plan to meet specified criteria; (3) conducting simulations for load and generation imbalance UFLS schemes; (4) implementing the UFLS scheme for entities with loads 100 MW or greater and for entities with

[5] 18 C.F.R. § 39.5(a) (2016).

[6] The Commission specified in Order No. 672 certain general factors it would consider when assessing whether a particular Reliability Standard is just and reasonable. *See Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, at P 262, 321-37, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006) ("Order No. 672").

loads less than 100 MW; (5) implementing changes to the scheme within a specified timeframe; and (6) providing certain information to SERC.

For the reasons discussed herein, NERC and SERC respectfully request the Commission approve proposed regional Reliability Standard PRC-006-SERC-02, the associated VRFs and VSLs, the Effective Date, and the retirement of the existing regional Reliability Standard PRC-006-SERC-01. The following petition presents the justification for approval and supporting documentation.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:[7]

Holly A. Hawkins*
General Counsel
Rebecca Poulsen*
Legal Counsel
SERC Reliability Corporation
3701 Arco Corporate Drive, Suite 300
Charlotte, NC 28273
(704) 414-5238
hhawkins@serc1.org
rpoulsen@serc1.org

Counsel for the SERC Reliability Corporation

Shamai Elstein*
Senior Counsel
Marisa Hecht*
Counsel
North American Electric Reliability Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 400-3000
shamai.elstein@nerc.net
marisa.hecht@nerc.net

Counsel for the North American Electric Reliability Corporation

III. BACKGROUND

The following background information is provided below: (a) an explanation of the regulatory framework for NERC and regional Reliability Standards; (b) an explanation of the

[7] Persons to be included on the Commission's service list are identified by an asterisk. NERC respectfully requests a waiver of Rule 203 of the Commission's regulations, 18 C.F.R. § 385.203 (2017), to allow the inclusion of more than two persons on the service list in this proceeding.

SERC regional Reliability Standards development process; and (c) the history of development of PRC-006-SERC-02.

A. Regulatory Framework

By enacting the Energy Policy Act of 2005,[8] Congress entrusted the Commission with the duties of approving and enforcing rules to ensure the reliability of the Nation's Bulk-Power System, and with the duties of certifying an ERO that would be charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval. Section 215(b)(1)[9] of the FPA states that all users, owners, and operators of the Bulk-Power System in the United States will be subject to Commission-approved Reliability Standards. Section 215(d)(5)[10] of the FPA authorizes the Commission to order the ERO to submit a new or modified Reliability Standard. Section 39.5(a)[11] of the Commission's regulations requires the ERO to file with the Commission for its approval each Reliability Standard that the ERO proposes should become mandatory and enforceable in the United States, and each modification to a Reliability Standard that the ERO proposes should be made effective.

The Commission has the regulatory responsibility to approve Reliability Standards that protect the reliability of the Bulk-Power System and to ensure that such Reliability Standards are just, reasonable, not unduly discriminatory or preferential, and in the public interest. Pursuant to Section 215(d)(2) of the FPA[12] and Section 39.5(c)[13] of the Commission's regulations, the

8 16 U.S.C. § 824o (2012).

9 *Id.* § 824o(b)(1).

10 *Id.* § 824o(d)(5).

11 18 C.F.R. § 39.5(a) (2017).

12 16 U.S.C. § 824o(d)(2).

13 18 C.F.R. § 39.5(c)(1).

Commission will give due weight to the technical expertise of the ERO with respect to the content of a Reliability Standard.

Similarly, the Commission approves regional Reliability Standards proposed by regional Entities if the regional Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest.[14] In addition, Order No. 672 requires further criteria for regional Reliability Standards. A regional difference from a continent-wide Reliability Standard must either be: (1) more stringent than the continent-wide Reliability Standard, or (2) necessitated by a physical difference in the Bulk-Power System.[15]

B. SERC Regional Reliability Standards Development Process

The proposed regional Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved SERC regional Standards Development Procedure.[16] In accepting NERC's delegation agreements with the Regional Entities, the Commission found that NERC's proposed common attributes for regional Reliability Standard development and SERC's Reliability Standards development process provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards and thus addresses certain of the criteria for approving Reliability Standards.[17] The development process is open to any person or entity that is an interested

---

[14] Section 215(d)(2) of the FPA and 18 C.F.R. §39.5(a).

[15] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, at P 291, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[16] *Amendments to Delegation Agreement with SERC Reliability Corporation*, Docket No. RR12-5-000 (June 12, 2012) (unpublished letter order) (approving revised SERC regional Standards Development Procedure), *available at* http://www.nerc.com/FilingsOrders/us/FERCOrdersRules/LetterOrder_ApprovingAmdmts_SERCDelegation_20120612.pdf; The SERC Regional Standards Development Procedure is available at https://www.serc1.org/docs/default-source/program-areas/standards-regional-criteria/standards-documents/serc-da-exhibit-c---regional-standards-development-procedure-(6-12-12).pdf?sfvrsn=9079681a_8.

[17] *Order Accepting ERO Compliance Filing, Accepting ERO/Regional Entity Delegation Agreements, and Accepting Regional Entity 2007 Business Plans*, 119 FERC ¶ 61,060 at P 17 (2007).

stakeholder. SERC considers the comments of all stakeholders, and a vote of stakeholders and the SERC Board of Directors is required to approve a regional Reliability Standard. In addition to SERC Board of Directors approval, NERC posts the regional Reliability Standard for an additional comment period. After the NERC posting and SERC Board of Directors approval, the NERC Board of Trustees must adopt the regional Reliability Standard before the regional Reliability Standard is submitted to the Commission for approval.

C. The Development History of Proposed PRC-006-SERC-02

As further described in Exhibit C hereto, proposed regional Reliability Standard PRC-006-SERC-02 was developed by the SERC Engineering Committee Dynamics Review Subcommittee as part of a periodic review of PRC-006-SERC-01. On May 10, 2017, proposed regional Reliability Standard PRC-006-SERC-02 received the requisite approval from the registered ballot body, with a 100 percent affirmative vote. The SERC Board of Directors approved the regional standard on June 28, 2017. NERC posted the regional standard for a 45-day comment period concluding on July 24, 2017. There were no additional changes after this comment period. The NERC Board of Trustees subsequently adopted the regional standard on August 10, 2017.

IV. JUSTIFICATION FOR APPROVAL

As discussed in detail in Exhibit B, proposed regional Reliability Standard PRC-006-SERC-02 – Automatic Underfrequency Load Shedding Requirements is just, reasonable, not unduly discriminatory or preferential, and in the public interest. As described more fully herein and in Exhibit B, the proposed regional Reliability Standard provides reliability benefits for the Bulk-Power System in the SERC region.

The purpose of proposed regional Reliability Standard PRC-006-SERC-02 is to establish consistent and coordinated requirements for the design, implementation, and analysis of automatic

UFLS programs among all SERC applicable entities. The provisions of the proposed regional standard provide specific requirements for the development, coordination, implementation, and analysis of UFLS schemes in the SERC region that are not included in the continent-wide Reliability Standard that addresses UFLS programs, Reliability Standard PRC-006-2 – Automatic Underfrequency Load Shedding. In approving PRC-006-SERC-01, the Commission stated that the regional Reliability Standard is, "designed to work in conjunction with NERC Reliability Standard PRC-006-1 to mitigate the consequences of an underfrequency event effectively while accommodating differences in system transmission and distribution topology among SERC planning coordinators due to historical design criteria, makeup of load demands, and generation resources."[18] Proposed PRC-006-SERC-02 provides this same benefit with additional proposed enhancements. Therefore, the proposed regional Reliability Standard meets a reliability need for the SERC region, and as discussed below, the proposed modifications provide additional support for the reliable operation of the Bulk-Power System.

The proposed regional standard includes requirements for including a Planning Coordinator's subregion as an identified island in the PRC-006-2 criteria (Requirement R1); selecting or developing a UFLS scheme that meets specified criteria (Requirement R2); conducting simulations of the UFLS scheme for an imbalance between load and generation when performing design assessments (Requirement R3); implementing the UFLS scheme in the SERC region for entities with a load of 100 MW or greater (Requirement R4); implementing the UFLS scheme in the SERC region for entities with a load of less than 100 MW (Requirement R5); implementing certain changes to the UFLS scheme within 18 months of notification by the Planning Coordinator

[18] *Regional Reliability Standard PRC-006-SERC-01 —Automatic Underfrequency Load Shedding Requirements*, Order No. 772, 141 FERC ¶ 61,243, at P 14 (2012) ("Order No. 772"). Note that the current version of continent-wide Reliability Standard PRC-006 is version 2, although at the time of approval of PRC-006-SERC-01 the continent-wide standard was version 1. Proposed PRC-006-SERC-02 still works in conjunction with currently-effective Reliability Standard PRC-006-2.

(Requirement R6); providing certain information to SERC (Requirement R7); and providing information for post-event analysis of frequency disturbances to SERC (Requirement R8).

This section of the petition addresses: (A) the justification of the need for the proposed regional Reliability Standard; (B) the description and technical basis of the proposed revisions; and (C) the enforceability of the proposed regional standard.

A. Justification for the Need for the Proposed Regional Reliability Standard

Proposed regional Reliability Standard PRC-006-SERC-02 meets the criteria to justify the need for a regional Reliability Standard as it is more stringent than the related continent-wide NERC Reliability Standard PRC-006-2, which does not include a detailed plan criteria or a maximum timeframe to implement changes to a UFLS scheme. As noted above, the Commission previously recognized that the additional specificity in the regional Reliability Standard helps to mitigate the consequences of an underfrequency event while accommodating differences in SERC system transmission and distribution topology.[19] Therefore, the proposed regional Reliability Standard PRC-006-SERC-02 is justified because it meets the criteria in Order No. 672 to be more stringent than continent-wide Reliability Standards. Entities that perform the functions to which the continent-wide standards and the proposed regional Reliability Standard apply need to comply with all applicable standards, so the proposed regional Reliability Standard provides a level of reliability support to the SERC region in addition to the continent-wide standards.

B. Description and Technical Basis of Proposed Revisions

The proposed revisions provide more flexibility for Planning Coordinators to determine the peak season on which to base the UFLS plan and clarify that it is not only distribution load that can be used for a UFLS scheme. The proposed revisions specify that Planning Coordinators

[19] *Id.*

may choose either summer or winter as the Peak Demand as part of its criteria for its UFLS scheme in Requirement R2, Part 2.1; remove "distribution" from Requirements R4, Part 4.1 and R5, Part 5.1; add the seasonal option to Requirements R4, Part 4.1 and R5, Part 5.1 to comport with the revisions in Requirement R2, Part 2.1; and clarify that an 18-month implementation timeframe is allowed with a change in Peak Demand season in Requirement R6.

In PRC-006-SERC-01, the requirements specify that the previous year's actual Peak Demand must be used to develop the UFLS plan. The proposed revisions add language that allows the Planning Coordinator to consider seasonal reliability concerns when specifying the peak on which to base the UFLS plan. As a result, the Planning Coordinator can choose either the summer or winter season rather than base the plan solely on the actual Peak Demand. This revision enables the Planning Coordinator to broaden its considerations in developing the UFLS plan to support reliability.

Recognizing that changing the peak season may require the installation of additional UFLS relays, the proposed revisions include an 18-month timeframe for affected entities to implement the plan. This timeframe allows for sufficient budgeting, procurement, and installation time for additional equipment or for significant setting changes to existing equipment necessary to meet a revised UFLS scheme. However, those entities that do not change their seasonal selection will implement PRC-006-SERC-02 as determined by the proposed Effective Date in Section V below.

The proposed revision to remove "distribution" to describe substation or feeder demand clarifies the language of the standard. This change removes the implication that only distribution load can be used for a UFLS scheme. The clarification supports reliability by ensuring that the Reliability Standard language is clear and unambiguous in accordance with Order No. 672 criteria.

C. Enforceability of Proposed Regional Reliability Standard PRC-006-SERC-02

The proposed regional Reliability Standard includes VRFs and VSLs that are unchanged from PRC-006-SERC-01. The VSLs provide guidance on the way that NERC will enforce the requirements of the proposed regional Reliability Standard. The VRFs are one of several elements used to determine an appropriate sanction when the associated requirement is violated. The VRFs assess the impact to reliability of violating a specific requirement. The VRFs and VSLs for the proposed regional Reliability Standard comport with NERC and Commission guidelines related to their assignment.

The proposed regional Reliability Standard also includes measures that support each requirement by clearly identifying what is required and how the requirement will be enforced. These measures help ensure that the requirements will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.[20]

V. EFFECTIVE DATE

NERC respectfully requests that the Commission approve the proposed regional Reliability Standard PRC-006-SERC-02 and the retirement of PRC-006-SERC-01 to become effective as set forth in the proposed Effective Date, provided in Exhibit A hereto. The proposed Effective Date of the proposed regional Reliability Standard is the on the first day of the first calendar quarter after approval by the Commission.

[20] Order No. 672 at P 327 ("There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. It should contain or be accompanied by an objective measure of compliance so that it can be enforced and so that enforcement can be applied in a consistent and non-preferential manner.").

VI. CONCLUSION

For the reasons set forth above, NERC respectfully requests that the Commission approve:

- the proposed regional Reliability Standard PRC-006-SERC-02 in **Exhibit A**;
- the other associated elements in the Reliability Standard in **Exhibit A**, including the VRFs and VSLs (**Exhibits A and B)**;
- the retirement of existing regional Reliability Standard PRC-006-SERC-01; and
- the Effective Date, included in **Exhibit A**.

Respectfully submitted,

/s/ Marisa Hecht

Holly A. Hawkins
General Counsel
Rebecca Poulsen
Legal Counsel
SERC Reliability Corporation
3701 Arco Corporate Drive, Suite 300
Charlotte, NC 28273
(704) 414-5238
hhawkins@serc1.org
rpoulsen@serc1.org

Counsel for the SERC Reliability Corporation

Shamai Elstein
Senior Counsel
Marisa Hecht
Counsel
North American Electric Reliability Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 400-3000
shamai.elstein@nerc.net
marisa.hecht@nerc.net

Counsel for the North American Electric Reliability Corporation

Date: September 8, 2017

EXHIBIT A:

Proposed Regional Reliability Standard, PRC-006-SERC-02 – Automatic Underfrequency Load Shedding Requirements, and Effective Date

Proposed Regional Reliability Standard, PRC-006-SERC-02 – Automatic Underfrequency Load Shedding Requirements, and Effective Date - CLEAN

Effective Date

Effective for SERC Region applicable Registered Entities on the first day of the first calendar quarter after approved by FERC

Introduction

1. **Title:** Automatic Underfrequency Load Shedding Requirements

2. **Number:** PRC-006-SERC–02

3. **Purpose:** To establish consistent and coordinated requirements for the design, implementation, and analysis of automatic underfrequency load shedding (UFLS) programs among all SERC applicable entities.

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** Generator Owners

5. **Background**

   The SERC UFLS Standard: PRC-006-SERC-01 ("SERC UFLS Standard") was developed to provide regional UFLS requirements to entities in SERC. UFLS requirements have been in place at a continent-wide level and within SERC for many years prior to implementation of federally mandated reliability compliance standards in 2007.

   When reliability standards were implemented in 2007, the Federal Energy Regulatory Commission ("FERC"), which is the government body with regulatory responsibility for electric reliability, issued FERC Order 693, recognizing 83 NERC Reliability Standards as enforceable by FERC and applicable to users, owners, and operators of the bulk power system (BPS). FERC did not approve the NERC UFLS standard, PRC-006-0 in Order 693. FERC's reason for not approving PRC-006-0 was that it recognized PRC-006-0 as a "fill-in the blank standard," and regional procedures associated with the standard were not submitted along with the standard. FERC's ruling in Order 693 required Regional Entities to provide the regional requirements necessary for completing the UFLS standard.

   In 2008, SERC commenced work on PRC-006-SERC-01. NERC also began work on revising PRC-006-0 at a continent-wide level. The SERC standard has been developed to be consistent with the NERC UFLS standard. PRC-006-SERC-02 was developed per periodic review of the standard.

   PRC-006-1 clearly defines the roles and responsibilities of parties to whom the standard applies. The standard identifies the Planning Coordinator ("PC") as the entity responsible for developing UFLS schemes within their PC area. The regional standard adds specificity not contained in the NERC standard for development and implementation of a UFLS scheme in the SERC Region that effectively mitigates the consequences of an underfrequency event.

Requirements and Measures

R1. Each Planning Coordinator shall include its SERC subregion as an identified island in the criteria (required by the NERC PRC standard on UFLS) for selecting portions of the BPS that may form islands. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1 A Planning Coordinator may adjust island boundaries to differ from subregional boundaries where necessary for the sole purpose of producing a contiguous subregional island more suitable for simulation.

M1. Each Planning Coordinator shall have evidence such as a methodology, procedure, report, or other documentation indicating that its criteria included selection of its SERC subregion(s) as an island per Requirement R1.

R2. Each Planning Coordinator shall select or develop an automatic UFLS scheme (percent of load to be shed, frequency set points, and time delays) for implementation by UFLS entities within its area that meets the following minimum requirements: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. Have the capability of shedding at least 30 percent of the Peak Demand (MW) served from the Planning Coordinator's transmission system. The Peak Demand may be either summer or winter as determined by the Planning Coordinator.

2.2. Shed load with a minimum of three frequency set points.

2.3. The highest frequency set point for relays used to arrest frequency decline shall be no lower than 59.3 Hz and not higher than 59.5 Hz.

2.3.1 This does not apply to UFLS relays with time delay of one second or longer and a higher frequency setpoint applied to prevent the frequency from stalling at less than 60 Hz when recovering from an underfrequency event.

2.4. The lowest frequency set point shall be no lower than 58.4 Hz.

2.5. The difference between frequency set points shall be at least 0.2 Hz but no greater than 0.5 Hz.

2.6. Time delay (from frequency reaching the set point to the trip signal) shall be at least six cycles.

M2. Each Planning Coordinator shall have evidence such as reports or other documentation that the UFLS scheme for its area meets the design requirements specified in Requirement R2.

R3. Each Planning Coordinator, when performing design assessments specified in the NERC PRC standard on UFLS, shall conduct simulations of its UFLS scheme for an imbalance between load and generation of 13%, 22%, and 25% for all identified island(s) where such imbalance equals [(load minus actual generation output) / load]. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M3. Each Planning Coordinator shall have evidence such as reports or other documentation that it performed the simulations of its UFLS scheme as required in Requirement R3.

R4. Each UFLS entity that has a total load of 100 MW or greater in a Planning Coordinator area in the SERC Region shall implement the UFLS scheme developed by their Planning Coordinator. UFLS entities may implement the UFLS scheme developed by the Planning Coordinator by coordinating with other UFLS entities. The UFLS scheme shall meet the following requirements on May 1 of each calendar year. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1. The percent of load shedding to be implemented shall be based on the actual or estimated substation or feeder demand (including losses) of the UFLS entities at the time coincident with the previous year's actual Peak Demand in the season specified by the Planning Coordinator in R2.

4. 2. The amount of load in each load shedding step shall be within -1.0 and +3.0 of the percentage specified by the Planning Coordinator (for example, if the specified percentage step load shed is 12%, the allowable range is 11 to 15%).

4. 3. The amount of total UFLS load of all steps combined shall be within -1.0 and +5.0 of the percentage specified by the Planning Coordinator for the total UFLS load in the UFLS scheme.

M4. Each UFLS entity that has a total load of 100 MW or greater in a Planning Coordinator area in the SERC Region shall have evidence such as reports or other documentation demonstrating that its implementation of the UFLS scheme on May 1 of each calendar year meets the requirements of Requirement R4 (including all the data elements in Parts 4.1, 4.2, and 4.3) unless scheme changes per Requirement R6 are in process.

R5. Each UFLS entity that has a total load less than 100 MW in a Planning Coordinator area in the SERC Region shall implement the UFLS scheme developed by their Planning Coordinator, but shall not be required to have more than one UFLS step. UFLS entities may implement the UFLS scheme developed by the Planning Coordinator by coordinating with other UFLS entities. The UFLS scheme shall meet the following requirements on May 1 of each calendar year. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning].*

5.1. The percent of load shedding to be implemented shall be based on the actual or estimated substation or feeder demand (including losses) of the UFLS entities at the time coincident with the previous year actual Peak Demand in the season specified by the Planning Coordinator in R2..

5.2. The amount of total UFLS load shall be within ± 5.0 of the percentage specified by the Planning Coordinator for the total UFLS load in the UFLS scheme.

M5. Each UFLS entity that has a total load less than 100 MW in a Planning Coordinator area in the SERC Region shall have evidence such as reports or other documentation demonstrating that its implementation of the UFLS scheme on May 1 of each calendar year meets the requirements of Requirement R5 (including all the data elements in Parts 5.1and 5.2) unless scheme changes per Requirement R6 are in process.

R6. Each UFLS entity shall implement changes to the UFLS scheme which involve frequency settings, relay time delays, changes to the percentage of load in the scheme, or changes to the peak season selected in R2.1 within 18 months of notification by the Planning Coordinator. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M6. Each UFLS entity shall have evidence such as reports or other documentation demonstrating that it has made the appropriate scheme changes within 18 months per Requirement R6. Such evidence is only required if the Planning Coordinator makes changes to the UFLS scheme as specified in Requirement R6.

R7. Each Planning Coordinator shall provide the following information to SERC according to the schedule specified by SERC. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

7.1. Underfrequency trip set points (Hz)

7.2. Total clearing time associated with each set point (sec). This includes the time from when frequency reaches the set point and ends when the breaker opens.

7.3. Amount of previous year actual or estimated load associated with each set point, both in percent and in MW. The percentage and the Load demand (MW) shall be based on the time coincident with the previous year actual Peak Demand.

M7. Each Planning Coordinator shall have evidence such as reports or other documentation that data specified in Requirement R7 was provided to SERC in accordance with the schedule.

R8. Each Generator Owner shall provide the following information within 30 days of a request by SERC to facilitate post-event analysis of frequency disturbances. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

8.1. Generator protection automatic underfrequency and overfrequency trip set points (Hz).

8.2. Total clearing time associated with each set point (sec). This is defined as the time that begins when frequency reaches the set point and ends when the breaker opens. If inverse time underfrequency relays are used, provide the total clearing time at 59.0, 58.5, 58.0, and 57.0 Hz.

8.3. Maximum generator net MW that could be tripped automatically due to an underfrequency or overfrequency condition.

M8. Each Generator Owner shall have evidence such as reports or other documentation that data specified in Requirement R8 was provided to SERC as requested.

Compliance

Compliance enforcement authority

SERC Reliability Corporation

Compliance monitoring and assessment process

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaint

Evidence retention

Each Planning Coordinator, UFLS Entity and Generator Owner shall keep data or evidence to show compliance as identified below unless directed by SERC to retain specific evidence for a longer period of time as part of an investigation.

Each Planning Coordinator, UFLS Entity and Generator Owner shall retain the current evidence of each Requirement and Measure as well as any evidence necessary to show compliance since the last compliance audit.

If a Planning Coordinator, UFLS Entity or Generator Owner 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.

Time Horizons, Violation Risk Factors, and Violation Severity Levels

Table 1						
R#	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
R1	Long-term Planning	Medium	N/A	N/A	N/A	The Planning Coordinator did not have evidence that its criteria included selection of its SERC subregion(s) as an island, with or without adjusted boundaries.
R2	Long-term Planning	Medium	The Planning Coordinator's scheme did not meet one of the UFLS system design requirements identified in 2.2 through 2.6	The Planning Coordinator's scheme did not meet two of the UFLS system design requirements identified in 2.2 through 2.6.	The Planning Coordinator's scheme did not meet three of the UFLS system design requirements identified in 2.2 through 2.6.	The Planning Coordinator's scheme did not meet 2.1 **OR** Four or more of the UFLS system design requirements identified in 2.2 through 2.6.
R3	Long-term Planning	High	N/A	The Planning Coordinator failed to conduct one of the required simulations of its UFLS scheme.	N/A	The Planning Coordinator failed to conduct two of the required simulations of its UFLS scheme.
R4	Operations Planning	Medium	The UFLS entity's implemented UFLS scheme had one load shedding step outside the range specified in 4.	The UFLS entity's implemented UFLS scheme had two load shedding steps outside the range specified in 4.	The UFLS entity's implemented UFLS scheme had three or more load shedding steps outside the range	The UFLS entity's implemented UFLS scheme had three or more load shedding steps outside the range

Table 1						
R#	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
			2.	2.	specified in 4.2. **OR** The UFLS entity's implemented UFLS scheme had a total load outside the range specified in 4.3.	specified in 4.2. **AND** The UFLS entity's implemented UFLS scheme had a total load outside the range specified in 4.3.
R5	Operations Planning	Medium	N/A	N/A	N/A	The UFLS entity's implemented UFLS scheme had a total load outside the range specified in 5.2.
R6	Long-term Planning	High	The UFLS entity implemented required scheme changes but made them 1 to 30 days after the scheduled date.	The UFLS entity implemented required scheme changes but made them 31 to 40 days after the scheduled date.	The UFLS entity implemented required scheme changes but made them 41 to 50 days after the scheduled date.	The UFLS entity implemented required scheme changes but made them more than 50 days after the scheduled date OR The UFLS entity failed to implement the required scheme changes.
R7	Long-term Planning	Lower	The Planning Coordinator provided the data required in R7 to SERC 1 to 10 days	The Planning Coordinator provided the data required in R7 to SERC 11 to 20 days	The Planning Coordinator provided the data required in R7 to SERC 21 to 30 days	The Planning Coordinator provided the data required in R7 to SERC more than 30

Table 1						
R#	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
			after the scheduled submittal date.	after the scheduled submittal date. **OR** The Planning Coordinator did not provide to SERC one piece of information listed in R7.	after the scheduled submittal date. **OR** The Planning Coordinator did not provide to SERC two pieces of information listed in R7.	days after the scheduled submittal date. **OR** The Planning Coordinator did not provide to SERC any of the information listed in R7.
R8	Long-term Planning	Lower	The Generator Owner provided the data required in R8 to SERC 1 to 10 days after the requested submittal date.	The Generator Owner provided the data required in R8 to SERC 11 to 20 days after the requested submittal date. **OR** The Generator Owner did not provide to SERC one piece of information listed in R8.	The Generator Owner provided the data required in R8 to SERC 21 to 30 days after the requested submittal date. **OR** The Generator Owner did not provide to SERC two pieces of information listed in R8.	The Generator Owner provided the data required in R8 to SERC more than 30 days after the requested submittal date. **OR** The Generator Owner did not provide to SERC any of the information listed in R8.

Regional Variances

None

Interpretations

None

Guideline and Technical Basis

1. **Existing UFLS schemes**
   Each Planning Coordinator should consider the existing UFLS programs which are in place and should consider input from the UFLS entities in developing the UFLS scheme.

2. **Basis for SERC standard requirements**
   SERC Standard PRC-006-SERC-02 is not a stand-alone standard, but was written to be followed in conjunction with NERC Standard PRC-006-1. The primary focus of SERC Standard PRC-006-SERC-02 was to provide region-specific requirements for the implementation of the higher tier NERC standard requirements with the goals of a) adding clarity and b) providing for consistency and a coordinated UFLS scheme for the SERC Region as a whole.
   Generally speaking, requirements already in the NERC standard were not repeated in the SERC standard. Therefore, both the NERC and SERC standards must be followed to ensure full compliance.

3. **Basis for applying a percentage load shedding value to Forecast Load versus Actual Load**
   The Planning Coordinator will develop a UFLS scheme to meet the performance requirements of NERC Standard PRC-006-2 Requirement R3 and SERC Standard PRC-006-SERC-02 Requirement R2. This development will result in certain percentages of load for each UFLS entity in the Planning Coordinator's area for which automatic under frequency load shedding must be implemented. The Planning Coordinator develops these percentages based on forecast peak load demand. However, the UFLS entity implements these percentages based on the previous year's actual peak demand. Applying the same percentage to these different base values was intentional to ensure that both the Planning Coordinator and UFLS entities had a clear, measurable value to use in performing their respective roles in meeting the standard. Planning Coordinators typically use forecast demands in their work. Whereas the previous year's actual (or estimated) demand is typically more available to UFLS entities. Additionally, the use of percentages based on these different base values tends to minimize the error due to the time lag between design and actual field implementation. Since a percentage is provided by the Planning Coordinator to the UFLS entities, any differences between the design values (i.e., forecast load) and the implemented values (i.e., previous year's actual) would naturally tend to match up reasonably well. For example, if the total planning area load in MW for which UFLS was installed during the time of implementation was slightly higher or lower than the MW value used in the design by the Planning Coordinator, multiplying by the specified percentage would result in an implemented load shedding scheme that also had a reasonably similar higher or lower MW value.

4. **Basis for May 1 and 18 month time frames**
   Each UFLS entity must annually review that the amount of UFLS load shedding implemented is within a certain tolerance as specified by SERC Standard PRC-006-SERC-02 Requirement R 4 or Requirement R5 by May 1 of the current year. May 1 was chosen to allow sufficient time after the previous year's peak occurred to make adjustments in the field to the implementation if necessary to meet the tolerances specified in Requirement R4 or Requirement R5. Therefore, the May 1 date applies only to implementation of the existing percentages of load shedding specified by the Planning Coordinator. On the other hand, the 18-month time frame specified in PRC-006-SERC-02 Requirement R6 is intended to allow sufficient budgeting, procurement, and installation time for additional equipment, or for significant setting changes to existing equipment necessary to meet a revised load shedding scheme design that has been specified by the Planning Coordinator. During this 18-month transition period, the May 1 measurement of R4 or Requirement R5 would not apply.

5. **Basis for smaller entity threshold of 100 MW**
   Most distribution substations have transformers rated in the range of 10 to 40 MVA. Usually most transformers would serve 1 to 4 feeders and each feeder will normally carry between 8 and 10 MVA. In general, assuming that each feeder would carry 10 MW, an entity with a load slightly greater than 100 MW would have at least 10 feeders available. For a program with three 10 % steps, only 3 feeders would be required to have under frequency load shed capabilities. The 100 MW threshold seems to provide adequate flexibility for implementing load shedding in three steps for entities slightly greater than 100 MW.

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 each of the rationale text boxes was moved to this section.

Rationale for R1:

Studying the Region as an island is required by the NERC standard. Most regions have only one or a few different UFLS schemes. Where there is more than one scheme, studying this island demonstrates that the schemes are coordinated and performing adequately. Because there are so many different UFLS schemes in SERC (18 different schemes were represented in the 2007 SERC UFLS study), the SDT believes that applying the schemes to each subregion as an island is a necessary additional test of the coordination of the various UFLS schemes. Without this additional test, a poorly performing scheme may be masked by the large number of good performing schemes in the Region. A subregion island study, which would have a smaller number of schemes, would be more likely to uncover the poorly performing scheme and therefore get it fixed. This approach will result in a much better overall performance of the UFLS programs in SERC. The SDT recognized that there may be simulation problems due to opening the ties to utilities outside the subregion. Therefore, the subregion island boundaries are allowed to be adjusted to produce an island more suitable for simulation.

(Note: The SERC Subregions are identified in paragraph 4.2 of the SERC Reliability Corporation Bylaws: "The Region is currently geographically divided into five subregions that are identified as Southeastern, Central, VACAR, Delta, and Gateway.")

Rationale for R2:
These requirements for the UFLS schemes in SERC have been in place for many years (except 2.6). The SDT believes that these requirements are still needed to ensure consistency for the various schemes which are used in SERC. Part 2.6 is designed to prevent spurious operations due to transient frequency swings.

Rationale for R3:
R4 of the NERC standard PRC-006-1 requires the PC to conduct assessments of UFLS schemes through dynamic simulations to verify that they meet performance requirements for generation/load imbalances of up to 25%. This requirement defines specific imbalances that are to be studied within SERC. The 13% and 22% levels were determined from simulations of the worst case frequency overshoot for the UFLS schemes in SERC.

Rationale for R4:
The SDT believes it is necessary to put a requirement on how well the UFLS scheme is implemented. This requirement specifies how close the actual load shedding amounts must be to the percentage of load called for in the scheme. A 4 percentage point range is allowed for each individual step, but the allowed range for all steps combined is 6 percentage points.

Rationale for R5:
The SDT believes it is necessary to put a requirement on how well the UFLS scheme is implemented. This requirement specifies how close the actual load shedding amounts must be to the percentage of load called for in the scheme. The SDT recognizes that UFLS entities with a load of less than 100 MW may have difficulty in implementing more than one UFLS step and in meeting a tight tolerance. The basis of the 100 MW comes from typical feeder load dropped by UFLS relays, and the use of a 100 MW threshold in other regional UFLS standards.

Rationale for R6:
The SDT believes it is necessary to put a requirement on how quickly changes to the scheme should be implemented. This requirement specifies that changes must be implemented within 18 months of notification by the PC. The 18 month interval was chosen to give a reasonable amount of time for making changes in the field. All of the SERC Region has existing UFLS schemes which, based on periodic simulations, have provided reliable protection for years. Events which result in islanding and an activation of the UFLS schemes are extremely rare in SERC. Therefore, the SDT does not believe that changes to an existing UFLS scheme will be needed in less than 18 months. However, if a PC determines there is a need for changing the UFLS scheme faster than 18 months, then the PC may require the implementation to be done sooner as allowed by NERC Reliability Standard PRC-006-1.

Rationale for R7:
The NERC standard requires that a UFLS database be maintained by the Planning Coordinator. This requirement specifies what data must be reported to SERC. A SERC UFLS database is needed to facilitate data sharing across the SERC Region, with other regions, and with NERC.

Rationale for R8:
The SDT believes that generator over and under frequency tripping data is needed to supplement the UFLS data provided by the Planning Coordinator for post-event analysis of frequency disturbances. This requirement states what data must be reported to SERC by the Generator Owners.

Since the inverse time curve cannot easily be placed into the SERC database, four clearing times based on data from the curve are requested. These clearing times are intended to cover a range of frequencies needed for event replication as well as provide information about generators that trip at a higher frequency than is allowed by the NERC standard.

Version History

Version	Date	Action	Change Tracking
1	September 19, 2011	SERC Board Approved	
1	November 3, 2011	Adopted by NERC Board of Trustees	
1	December 20, 2012	FERC Order issued approving PRC-006-SERC–01	
1	March 11, 2013	Modified the Rationale and changed the VRF for Requirement R6 from “Medium” to “High” per a compliance filing (Filed on 3/11/13)	
2	June 28, 2017	SERC Board Approved	
2	August 10, 2017	Adopted by NERC Board of Trustees	

*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard PRC-006-SERC-02 — Automatic Underfrequency Load Shedding Requirements

United States

Standard	Requirement	Enforcement Date	Inactive Date
PRC-006-SERC-02	All	TBD	

Proposed Regional Reliability Standard, PRC-006-SERC-02 – Automatic Underfrequency Load Shedding Requirements, and Effective Date - REDLINE

Effective Dates

Effective for SERC Region applicable Registered Entities on the first day of the first calendar quarter after approved by FERC

Requirement	Jurisdiction									
	Alberta	British Columbia	Manitoba	New Brunswick	Newfound-land	Nova Scotia	Ontario	Quebec	Saskatch-ewan	USA
R1	NA	NA	NA	NA	NA	NA	NA	NA	NA	4/1/14
R2	NA	NA	NA	NA	NA	NA	NA	NA	NA	4/1/14
R3	NA	NA	NA	NA	NA	NA	NA	NA	NA	10/1/14
R4, R5, and R6	NA	NA	NA	NA	NA	NA	NA	NA	NA	10/1/15
R7	NA	NA	NA	NA	NA	NA	NA	NA	NA	4/1/14
R8	NA	NA	NA	NA	NA	NA	NA	NA	NA	4/1/14

Requirement R1 shall become effective 12 months after the first day of the first quarter following regulatory approval, but no sooner than 12 months following regulatory approval of NERC PRC-006-1. This 12-month period is consistent with the effective date of R2 of PRC-006-1.

Requirement R2 shall become effective 12 months after the first day of the first quarter following regulatory approval. This 12-month period is needed to allow time for entities to ensure a minimum time delay of six cycles on existing UFLS relays as specified in part 2.6.

~~Requirements R3 shall become effective 18 months after the first day of the first quarter following regulatory approval. This additional six-month period is needed to allow time to perform and coordinate studies necessary to assess the overall effectiveness of the UFLS schemes in the SERC Region.~~

~~Requirements R4, R5, and R6 shall become effective 30 months after the first day of the first quarter following regulatory approval. This additional 18 months is needed to allow time for any necessary changes to be made to the existing UFLS schemes in the SERC Region.~~

~~Requirement R7 shall become effective six months following the effective date of R8 of the NERC standard PRC-006-1, but no sooner than one year following the first day of the first calendar quarter after applicable regulatory approval of PRC-006-SERC-01. R8 of the NERC standard requires each UFLS entity to provide UFLS data to the Planning Coordinator (PC). R7 of the SERC standard requires the PC to provide this data to SERC.~~

~~Requirement R8 shall become effective 12 months after the first day of the first quarter following regulatory approval. This 12-month period is needed to allow time for Generator Owners (GO) to collect and make an initial data filing.~~

Introduction

1. **Title:** Automatic Underfrequency Load Shedding Requirements

2. **Number:** PRC-006-SERC–0~~1~~2

3. **Purpose:** To establish consistent and coordinated requirements for the design, implementation, and analysis of automatic underfrequency load shedding (UFLS) programs among all SERC applicable entities.

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** Generator Owners

5. **Background**

The SERC UFLS Standard: PRC-006-SERC-01 ("SERC UFLS Standard") was developed to provide regional UFLS requirements to entities in SERC. UFLS requirements have been in place at a continent-wide level and within SERC for many years prior to implementation of federally mandated reliability compliance standards in 2007.

When reliability standards were implemented in 2007, the Federal Energy Regulatory Commission ("FERC"), which is the government body with regulatory responsibility for electric reliability, issued FERC Order 693, recognizing 83 NERC Reliability Standards as enforceable by FERC and applicable to users, owners, and operators of the bulk power system (BPS). FERC did not approve the NERC UFLS standard, PRC-006-0 in Order 693. FERC's reason for not approving PRC-006-0 was that it recognized PRC-006-0 as a "fill-in the blank standard," and regional procedures associated with the standard were not submitted along with the standard. FERC's ruling in Order 693 required Regional Entities to provide the regional requirements necessary for completing the UFLS standard.

In 2008, SERC commenced work on PRC-006-SERC-01. NERC also began work on revising PRC-006-0 at a continent-wide level. The SERC standard has been developed to be consistent with the NERC UFLS standard. PRC-006-SERC-02 was developed per periodic review of the standard.

PRC-006-1 clearly defines the roles and responsibilities of parties to whom the standard applies. The standard identifies the Planning Coordinator ("PC") as the entity responsible for developing UFLS schemes within their PC area. The regional standard adds specificity not contained in the NERC standard for development and implementation of a UFLS scheme in the SERC Region that effectively mitigates the consequences of an underfrequency event.

Requirements and Measures

R1. Each Planning Coordinator shall include its SERC subregion as an identified island in the criteria (required by the NERC PRC standard on UFLS) for selecting portions of the BPS that may form islands. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1 A Planning Coordinator may adjust island boundaries to differ from subregional boundaries where necessary for the sole purpose of producing a contiguous subregional island more suitable for simulation.

M1. Each Planning Coordinator shall have evidence such as a methodology, procedure, report, or other documentation indicating that its criteria included selection of its SERC subregion(s) as an island per Requirement R1.

R2. Each Planning Coordinator shall select or develop an automatic UFLS scheme (percent of load to be shed, frequency set points, and time delays) for implementation by UFLS entities within its area that meets the following minimum requirements: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. Have the capability of shedding at least 30 percent of the Peak Demand (MW) served from the Planning Coordinator's transmission system. The Peak Demand may be either summer or winter as determined by the Planning Coordinator.

2.2. Shed load with a minimum of three frequency set points.

2.3. The highest frequency set point for relays used to arrest frequency decline shall be no lower than 59.3 Hz and not higher than 59.5 Hz.

2.3.1 This does not apply to UFLS relays with time delay of one second or longer and a higher frequency setpoint applied to prevent the frequency from stalling at less than 60 Hz when recovering from an underfrequency event.

2.4. The lowest frequency set point shall be no lower than 58.4 Hz.

2.5. The difference between frequency set points shall be at least 0.2 Hz but no greater than 0.5 Hz.

2.6. Time delay (from frequency reaching the set point to the trip signal) shall be at least six cycles.

M2. Each Planning Coordinator shall have evidence such as reports or other documentation that the UFLS scheme for its area meets the design requirements specified in Requirement R2.

R3. Each Planning Coordinator, when performing design assessments specified in the NERC PRC standard on UFLS, shall conduct simulations of its UFLS scheme for an imbalance between load and generation of 13%, 22%, and 25% for all identified island(s) where such imbalance equals [(load minus actual generation output) / load]. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M3. Each Planning Coordinator shall have evidence such as reports or other documentation that it performed the simulations of its UFLS scheme as required in Requirement R3.

R4. Each UFLS entity that has a total load of 100 MW or greater in a Planning Coordinator area in the SERC Region shall implement the UFLS scheme developed by their Planning Coordinator. UFLS entities may implement the UFLS scheme developed by the Planning Coordinator by coordinating with other UFLS entities. The UFLS scheme shall meet the following requirements on May 1 of each calendar year. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1. The percent of load shedding to be implemented shall be based on the actual or estimated ~~distribution~~ substation or feeder demand (including losses) of the UFLS entities at the time coincident with the previous year's actual Peak Demand in the season specified by the Planning Coordinator in R2.

4. 2. The amount of load in each load shedding step shall be within -1.0 and +3.0 of the percentage specified by the Planning Coordinator (for example, if the specified percentage step load shed is 12%, the allowable range is 11 to 15%).

4. 3. The amount of total UFLS load of all steps combined shall be within -1.0 and +5.0 of the percentage specified by the Planning Coordinator for the total UFLS load in the UFLS scheme.

M4. Each UFLS entity that has a total load of 100 MW or greater in a Planning Coordinator area in the SERC Region shall have evidence such as reports or other documentation demonstrating that its implementation of the UFLS scheme on May 1 of each calendar year meets the requirements of Requirement R4 (including all the data elements in Parts 4.1, 4.2, and 4.3) unless scheme changes per Requirement R6 are in process.

R5. Each UFLS entity that has a total load less than 100 MW in a Planning Coordinator area in the SERC Region shall implement the UFLS scheme developed by their Planning Coordinator, but shall not be required to have more than one UFLS step. UFLS entities may implement the UFLS scheme developed by the Planning Coordinator by coordinating with other UFLS entities. The UFLS scheme shall meet the following requirements on May 1 of each calendar year. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning].*

5.1. The percent of load shedding to be implemented shall be based on the actual or estimated ~~distribution~~ substation or feeder demand (including losses) of the UFLS entities at the time coincident with the previous year actual Peak Demand in the season specified by the Planning Coordinator in R2.

5.2. The amount of total UFLS load shall be within ± 5.0 of the percentage specified by the Planning Coordinator for the total UFLS load in the UFLS scheme.

M5. Each UFLS entity that has a total load less than 100 MW in a Planning Coordinator area in the SERC Region shall have evidence such as reports or other documentation demonstrating that its implementation of the UFLS scheme on May 1 of each calendar year meets the requirements of Requirement R5 (including all the data elements in Parts 5.1and 5.2) unless scheme changes per Requirement R6 are in process.

R6. Each UFLS entity shall implement changes to the UFLS scheme which involve frequency settings, relay time delays, ~~or~~ changes to the percentage of load in the scheme, or changes to the peak season selected in R2.1 within 18 months of notification by the Planning Coordinator. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M6. Each UFLS entity shall have evidence such as reports or other documentation demonstrating that it has made the appropriate scheme changes within 18 months per Requirement R6. Such evidence is only required if the Planning Coordinator makes changes to the UFLS scheme as specified in Requirement R6.

R7. Each Planning Coordinator shall provide the following information to SERC according to the schedule specified by SERC. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

7.1. Underfrequency trip set points (Hz)

7.2. Total clearing time associated with each set point (sec). This includes the time from when frequency reaches the set point and ends when the breaker opens.

7.3. Amount of previous year actual or estimated load associated with each set point, both in percent and in MW. The percentage and the Load demand (MW) shall be based on the time coincident with the previous year actual Peak Demand.

M7. Each Planning Coordinator shall have evidence such as reports or other documentation that data specified in Requirement R7 was provided to SERC in accordance with the schedule.

R8. Each Generator Owner shall provide the following information within 30 days of a request by SERC to facilitate post-event analysis of frequency disturbances. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

8.1. Generator protection automatic underfrequency and overfrequency trip set points (Hz).

8.2. Total clearing time associated with each set point (sec). This is defined as the time that begins when frequency reaches the set point and ends when the breaker opens. If inverse time underfrequency relays are used, provide the total clearing time at 59.0, 58.5, 58.0, and 57.0 Hz.

8.3. Maximum generator net MW that could be tripped automatically due to an underfrequency or overfrequency condition.

M8. Each Generator Owner shall have evidence such as reports or other documentation that data specified in Requirement R8 was provided to SERC as requested.

Compliance

Compliance enforcement authority

SERC Reliability Corporation

Compliance monitoring and assessment process

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaint

Evidence retention

Each Planning Coordinator, UFLS Entity and Generator Owner shall keep data or evidence to show compliance as identified below unless directed by SERC to retain specific evidence for a longer period of time as part of an investigation.

Each Planning Coordinator, UFLS Entity and Generator Owner shall retain the current evidence of each Requirement and Measure as well as any evidence necessary to show compliance since the last compliance audit.

If a Planning Coordinator, UFLS Entity or Generator Owner 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.

Time Horizons, Violation Risk Factors, and Violation Severity Levels

Table 1						
R#	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
R1	Long-term Planning	Medium	N/A	N/A	N/A	The Planning Coordinator did not have evidence that its criteria included selection of its SERC subregion(s) as an island, with or without adjusted boundaries.
R2	Long-term Planning	Medium	The Planning Coordinator's scheme did not meet one of the UFLS system design requirements identified in 2.2 through 2.6	The Planning Coordinator's scheme did not meet two of the UFLS system design requirements identified in 2.2 through 2.6.	The Planning Coordinator's scheme did not meet three of the UFLS system design requirements identified in 2.2 through 2.6.	The Planning Coordinator's scheme did not meet 2.1 **OR** Four or more of the UFLS system design requirements identified in 2.2 through 2.6.
R3	Long-term Planning	High	N/A	The Planning Coordinator failed to conduct one of the required simulations of its UFLS scheme.	N/A	The Planning Coordinator failed to conduct two of the required simulations of its UFLS scheme.
R4	Operations Planning	Medium	The UFLS entity's implemented UFLS scheme had one load shedding step outside the range specified in 4.	The UFLS entity's implemented UFLS scheme had two load shedding steps outside the range specified in 4.	The UFLS entity's implemented UFLS scheme had three or more load shedding steps outside the range	The UFLS entity's implemented UFLS scheme had three or more load shedding steps outside the range

Table 1						
R#	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
			2.	2.	specified in 4.2. **OR** The UFLS entity's implemented UFLS scheme had a total load outside the range specified in 4.3.	specified in 4.2. **AND** The UFLS entity's implemented UFLS scheme had a total load outside the range specified in 4.3.
R5	Operations Planning	Medium	N/A	N/A	N/A	The UFLS entity's implemented UFLS scheme had a total load outside the range specified in 5.2.
R6	Long-term Planning	High	The UFLS entity implemented required scheme changes but made them 1 to 30 days after the scheduled date.	The UFLS entity implemented required scheme changes but made them 31 to 40 days after the scheduled date.	The UFLS entity implemented required scheme changes but made them 41 to 50 days after the scheduled date.	The UFLS entity implemented required scheme changes but made them more than 50 days after the scheduled date OR The UFLS entity failed to implement the required scheme changes.
R7	Long-term Planning	Lower	The Planning Coordinator provided the data required in R7 to SERC 1 to 10 days	The Planning Coordinator provided the data required in R7 to SERC 11 to 20 days	The Planning Coordinator provided the data required in R7 to SERC 21 to 30 days	The Planning Coordinator provided the data required in R7 to SERC more than 30

Table 1						
R#	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
			after the scheduled submittal date.	after the scheduled submittal date. **OR** The Planning Coordinator did not provide to SERC one piece of information listed in R7.	after the scheduled submittal date. **OR** The Planning Coordinator did not provide to SERC two pieces of information listed in R7.	days after the scheduled submittal date. **OR** The Planning Coordinator did not provide to SERC any of the information listed in R7.
R8	Long-term Planning	Lower	The Generator Owner provided the data required in R8 to SERC 1 to 10 days after the requested submittal date.	The Generator Owner provided the data required in R8 to SERC 11 to 20 days after the requested submittal date. **OR** The Generator Owner did not provide to SERC one piece of information listed in R8.	The Generator Owner provided the data required in R8 to SERC 21 to 30 days after the requested submittal date. **OR** The Generator Owner did not provide to SERC two pieces of information listed in R8.	The Generator Owner provided the data required in R8 to SERC more than 30 days after the requested submittal date. **OR** The Generator Owner did not provide to SERC any of the information listed in R8.

Regional Variances

None

Interpretations

None

Guideline and Technical Basis

1. **Existing UFLS schemes**
   Each Planning Coordinator should consider the existing UFLS programs which are in place and should consider input from the UFLS entities in developing the UFLS scheme.

2. **Basis for SERC standard requirements**
   SERC Standard PRC-006-SERC-~~01~~ 02 is not a stand-alone standard, but was written to be followed in conjunction with NERC Standard PRC-006-1. The primary focus of SERC Standard PRC-006-SERC-~~01~~ 02 was to provide region-specific requirements for the implementation of the higher tier NERC standard requirements with the goals of a) adding clarity and b) providing for consistency and a coordinated UFLS scheme for the SERC Region as a whole. Generally speaking, requirements already in the NERC standard were not repeated in the SERC standard. Therefore, both the NERC and SERC standards must be followed to ensure full compliance.

3. **Basis for applying a percentage load shedding value to Forecast Load versus Actual Load**
   The Planning Coordinator will develop a UFLS scheme to meet the performance requirements of NERC Standard PRC-006-~~1~~ 2 Requirement R3 and SERC Standard PRC-006-SERC-~~01~~ 02 Requirement R2. This development will result in certain percentages of load for each UFLS entity in the Planning Coordinator's area for which automatic under frequency load shedding must be implemented. The Planning Coordinator develops these percentages based on forecast peak load demand. However, the UFLS entity implements these percentages based on the previous year's actual peak demand. Applying the same percentage to these different base values was intentional to ensure that both the Planning Coordinator and UFLS entities had a clear, measurable value to use in performing their respective roles in meeting the standard. Planning Coordinators typically use forecast demands in their work. Whereas the previous year's actual (or estimated) demand is typically more available to UFLS entities. Additionally, the use of percentages based on these different base values tends to minimize the error due to the time lag between design and actual field implementation. Since a percentage is provided by the Planning Coordinator to the UFLS entities, any differences between the design values (i.e., forecast load) and the implemented values (i.e., previous year's actual) would naturally tend to match up reasonably well. For example, if the total planning area load in MW for which UFLS was installed during the time of implementation was slightly higher or lower than the MW value used in the design by the Planning Coordinator, multiplying by the specified percentage would result in an implemented load shedding scheme that also had a reasonably similar higher or lower MW value.

4. **Basis for May 1 and 18 month time frames**
   Each UFLS entity must annually review that the amount of UFLS load shedding implemented is within a certain tolerance as specified by SERC Standard PRC-006-SERC-~~01~~ 02 Requirement R 4 or Requirement R5 by May 1 of the current year. May 1 was chosen to allow sufficient time after the previous year's peak occurred to make adjustments in the field to the implementation if necessary to meet the tolerances specified in Requirement R4 or Requirement R5. Therefore, the May 1 date applies only to implementation of the existing percentages of load shedding specified by the Planning Coordinator. On the other hand, the 18-month time frame specified in PRC-006-SERC-~~01~~ 02 Requirement R6 is intended to allow sufficient budgeting, procurement, and installation time for additional equipment, or for significant setting changes to existing equipment necessary to meet a revised load shedding scheme design that has been specified by the Planning Coordinator. During this 18-month transition period, the May 1 measurement of R4 or Requirement R5 would not apply.

5. **Basis for smaller entity threshold of 100 MW**
   Most distribution substations have transformers rated in the range of 10 to 40 MVA. Usually most transformers would serve 1 to 4 feeders and each feeder will normally carry between 8 and 10 MVA. In general, assuming that each feeder would carry 10 MW, an entity with a load slightly greater than 100 MW would have at least 10 feeders available. For a program with three 10 % steps, only 3 feeders would be required to have under frequency load shed capabilities. The 100 MW threshold seems to provide adequate flexibility for implementing load shedding in three steps for entities slightly greater than 100 MW.

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 each of the rationale text boxes was moved to this section.

Rationale for R1:

Studying the Region as an island is required by the NERC standard. Most regions have only one or a few different UFLS schemes. Where there is more than one scheme, studying this island demonstrates that the schemes are coordinated and performing adequately. Because there are so many different UFLS schemes in SERC (18 different schemes were represented in the 2007 SERC UFLS study), the SDT believes that applying the schemes to each subregion as an island is a necessary additional test of the coordination of the various UFLS schemes. Without this additional test, a poorly performing scheme may be masked by the large number of good performing schemes in the Region. A subregion island study, which would have a smaller number of schemes, would be more likely to uncover the poorly performing scheme and therefore get it fixed. This approach will result in a much better overall performance of the UFLS programs in SERC. The SDT recognized that there may be simulation problems due to opening the ties to utilities outside the subregion. Therefore, the subregion island boundaries are allowed to be adjusted to produce an island more suitable for simulation.

(Note: The SERC Subregions are identified in paragraph 4.2 of the SERC Reliability Corporation Bylaws: "The Region is currently geographically divided into five subregions that are identified as Southeastern, Central, VACAR, Delta, and Gateway.")

Rationale for R2:
These requirements for the UFLS schemes in SERC have been in place for many years (except 2.6). The SDT believes that these requirements are still needed to ensure consistency for the various schemes which are used in SERC. Part 2.6 is designed to prevent spurious operations due to transient frequency swings.

Rationale for R3:
R4 of the NERC standard PRC-006-1 requires the PC to conduct assessments of UFLS schemes through dynamic simulations to verify that they meet performance requirements for generation/load imbalances of up to 25%. This requirement defines specific imbalances that are to be studied within SERC. The 13% and 22% levels were determined from simulations of the worst case frequency overshoot for the UFLS schemes in SERC.

Rationale for R4:
The SDT believes it is necessary to put a requirement on how well the UFLS scheme is implemented. This requirement specifies how close the actual load shedding amounts must be to the percentage of load called for in the scheme. A 4 percentage point range is allowed for each individual step, but the allowed range for all steps combined is 6 percentage points.

Rationale for R5:
The SDT believes it is necessary to put a requirement on how well the UFLS scheme is implemented. This requirement specifies how close the actual load shedding amounts must be to the percentage of load called for in the scheme. The SDT recognizes that UFLS entities with a load of less than 100 MW may have difficulty in implementing more than one UFLS step and in meeting a tight tolerance. The basis of the 100 MW comes from typical feeder load dropped by UFLS relays, and the use of a 100 MW threshold in other regional UFLS standards.

Rationale for R6:
The SDT believes it is necessary to put a requirement on how quickly changes to the scheme should be implemented. This requirement specifies that changes must be implemented within 18 months of notification by the PC. The 18 month interval was chosen to give a reasonable amount of time for making changes in the field. All of the SERC Region has existing UFLS schemes which, based on periodic simulations, have provided reliable protection for years. Events which result in islanding and an activation of the UFLS schemes are extremely rare in SERC. Therefore, the SDT does not believe that changes to an existing UFLS scheme will be needed in less than 18 months. However, if a PC determines there is a need for changing the UFLS scheme faster than 18 months, then the PC may require the implementation to be done sooner as allowed by NERC Reliability Standard PRC-006-1.

Rationale for R7:
The NERC standard requires that a UFLS database be maintained by the Planning Coordinator. This requirement specifies what data must be reported to SERC. A SERC UFLS database is needed to facilitate data sharing across the SERC Region, with other regions, and with NERC.

Rationale for R8:
The SDT believes that generator over and under frequency tripping data is needed to supplement the UFLS data provided by the Planning Coordinator for post-event analysis of frequency disturbances. This requirement states what data must be reported to SERC by the Generator Owners.

Since the inverse time curve cannot easily be placed into the SERC database, four clearing times based on data from the curve are requested. These clearing times are intended to cover a range of frequencies needed for event replication as well as provide information about generators that trip at a higher frequency than is allowed by the NERC standard.

Version History

Version	Date	Action	Change Tracking
1	September 19, 2011	SERC Board Approved	
1	November 3, 2011	Adopted by NERC Board of Trustees	
1	December 20, 2012	FERC Order issued approving PRC-006-SERC–01	
1	March 11, 2013	Modified the Rationale and changed the VRF for Requirement R6 from “Medium” to “High” per a compliance filing (Filed on 3/11/13)	
2	June 28, 2017	SERC Board Approved	
2	August 10, 2017	Adopted by NERC Board of Trustees	

*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard PRC-006-SERC-~~01~~ 02 — Automatic Underfrequency Load Shedding Requirements

United States

~~Standard~~	~~Requirement~~	~~Effective Date of Standard~~	~~Phased In Implementation Date (if applicable)~~	~~Inactive Date~~
~~PRC-006-SERC-01~~	~~R1.~~	~~04/01/2014~~		
~~PRC-006-SERC-01~~	~~1.1.~~	~~04/01/2014~~		
~~PRC-006-SERC-01~~	~~R2.~~	~~04/01/2014~~		
~~PRC-006-SERC-01~~	~~2.1.~~	~~04/01/2014~~		
~~PRC-006-SERC-01~~	~~2.2.~~	~~04/01/2014~~		
~~PRC-006-SERC-01~~	~~2.3.~~	~~04/01/2014~~		
~~PRC-006-SERC-01~~	~~2.3.1.~~	~~04/01/2014~~		
~~PRC-006-SERC-01~~	~~2.4.~~	~~04/01/2014~~		
~~PRC-006-SERC-01~~	~~2.5.~~	~~04/01/2014~~		
~~PRC-006-SERC-01~~	~~2.6.~~	~~04/01/2014~~		
~~PRC-006-SERC-01~~	~~R3.~~		~~10/01/2014~~	
~~PRC-006-SERC-01~~	~~R4.~~		~~10/01/2015~~	
~~PRC-006-SERC-01~~	~~4.1.~~		~~10/01/2015~~	
~~PRC-006-SERC-01~~	~~4.2.~~		~~10/01/2015~~	
~~PRC-006-SERC-01~~	~~4.3.~~		~~10/01/2015~~	
~~PRC-006-SERC-01~~	~~R5.~~		~~10/01/2015~~	
~~PRC-006-SERC-01~~	~~5.1.~~		~~10/01/2015~~	
~~PRC-006-SERC-01~~	~~5.2.~~		~~10/01/2015~~	

Standard	Requirement	Enforcement Date	Inactive Date
PRC-006-SERC-02	All	TBD	

Exhibit B

Order No. 672 Criteria for Proposed Regional Reliability Standard PRC-006-SERC-02

EXHIBIT B

Order No. 672 Criteria for Proposed PRC-006-SERC-02

In Order No. 672,[1] the Commission identified a number of criteria it will use to analyze Reliability Standards proposed for approval to ensure they are just, reasonable, not unduly discriminatory or preferential, and in the public interest. The discussion below identifies these factors and explains how the proposed regional Reliability Standard has met or exceeded the criteria:

1. **Proposed Reliability Standards must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve that goal.**[2]

The purpose of proposed regional Reliability Standard PRC-006-SERC-02 is to establish consistent and coordinated requirements for the design, implementation, and analysis of automatic UFLS programs among all SERC applicable entities. The proposed PRC-006-SERC-02 regional Reliability Standard is technically sound as it continues to meet the same performance of regional Reliability Standard PRC-006-SERC-01.[3] Proposed PRC-006-SERC-02 is more stringent than the related continent-wide NERC Reliability Standard PRC-006-2, which does not include detailed plan criteria or a maximum timeframe to implement changes to a UFLS scheme.

2. **Proposed Reliability Standards must be applicable only to users, owners and operators of the bulk power system, and must be clear and unambiguous as to**

---

[1] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[2] Order No. 672 at P 321.
Order No. 672 at P 324.

[3] PRC-006-SERC-01 was approved by the Commission on December 20, 2012. *See regional Reliability Standard PRC-006-SERC-01 – Automatic Underfrequency Load Shedding Requirements*, Order No. 772, 141 FERC ¶ 61,243 (2012).

what is required and who is required to comply.[4]

Proposed PRC-006-SERC-02 is only applicable to Planning Coordinators, UFLS entities, and Generator Owners within the SERC region. The proposed standard clarifies "UFLS entities" in Section 4.2 of the Applicability section of the standard. As explained in greater detail in the petition, the proposed regional Reliability Standard includes eight requirements that specify which entities should take action.

3. A proposed Reliability Standard must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation.[5]

Proposed PRC-006-SERC-02 does not have any changes to the VRFs and VSLs approved for PRC-006-SERC-01. The VRFs and VSLs for the proposed regional Reliability Standard continues to comport with NERC and Commission guidelines. The VSLs assigned for each Requirement ensure uniformity and consistency in the determination of penalties. The VSLs do not use any ambiguous terminology. For these reasons, the proposed regional Reliability Standards includes clear and understandable consequences in accordance with Order No. 672. Upon approval by the Commission, the ranges of penalties for violations will continue to be based on the applicable VRF and VSL in accordance with the sanctions table and the supporting penalty determination process described in the Commission-approved NERC Sanction Guidelines, Appendix 4B to the NERC Rules of Procedure.

---

[4] Order No. 672 at P 322.
Order No. 672 at P 325. The proposed Reliability Standard should be clear and unambiguous regarding what is required and who is required to comply. Users, owners, and operators of the Bulk-Power System must know what they are required to do to maintain reliability.

[5] Order No. 672 at P 326. The possible consequences, including range of possible penalties, for violating a proposed Reliability Standard should be clear and understandable by those who must comply.

4. A proposed Reliability Standard must identify clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non-preferential manner. [6]

Proposed PRC-006-SERC-02 identifies clear and objective criterion or measures for compliance so that it can be enforced in a consistent and non-preferential manner. The regional Reliability Standard contains individual measures that support the Requirements by plainly identifying how the Requirements will be assessed and enforced. These measures continue to ensure that the Requirements will be assessed and enforced in a clear, consistent, and non-preferential manner, without prejudice to any party.

5. Proposed Reliability Standards should achieve a reliability goal effectively and efficiently — but do not necessarily have to reflect "best practices" without regard to implementation cost or historical regional infrastructure design.[7]

Proposed PRC-006-SERC-02 achieves its reliability goals effectively and efficiently. The proposed revisions provide greater flexibility and clarity to registered entities responsible for compliance. The proposed regional Reliability Standard builds on the Bulk-Power System reliability protections provided by the NERC automatic UFLS standard by adding specificity for the SERC Region.

6. Proposed Reliability Standards cannot be "lowest common denominator," *i.e.*, cannot reflect a compromise that does not adequately protect Bulk-Power System reliability. Proposed Reliability Standards can consider costs to implement for smaller entities, but not at consequences of less than excellence in operating system reliability.[8]

Proposed PRC-006-SERC-02 does not reflect a compromise that does not adequately protect Bulk-Power System reliability.

7. Proposed Reliability Standards must be designed to apply throughout North America to the maximum extent achievable with a single Reliability Standard

---

6 Order No. 672 at P 327.
7 Order No. 672 at P 328.
8 Order No. 672 at P 329.
Order No. 672 at P 330.

while not favoring one geographic area or regional model. It should take into account regional variations in the organization and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.[9]

As a regional Reliability Standard, proposed PRC-006-SERC-02 is designed to work in conjunction with NERC Reliability Standard PRC-006-1 while accommodating differences in system transmission and distribution topology among SERC planning coordinators and will be enforceable for registered entities within the SERC region.

8. Proposed Reliability Standards should cause no undue negative effect on competition or restriction of the grid beyond any restriction necessary for reliability.[10]

The proposed regional Reliability Standard would not restrict competition or available transmission capability beyond what is necessary for reliability.

9. The implementation time for the proposed Reliability Standard is reasonable.[11]

The implementation time for the proposed regional Reliability Standard is reasonable. Because proposed PRC-006-SERC-02 provides additional flexibility and clarity rather than imposing any new obligations on registered entities, an effective date of the first day of the first calendar quarter after FERC approval is reasonable.

10. The Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[12]

The proposed regional Reliability Standard was developed in accordance with NERC's and SERC's Commission-approved processes for developing and approving Reliability Standards. SERC develops Regional Reliability Standards in accordance with the SERC

---

9 Order No. 672 at P 331.
10 Order No. 672 at P 332.
11 Order No. 672 at P 333.
12 Order No. 672 at P 334.

regional Standards Development Procedure. The development process is open to any person who is an interested stakeholder. For more detail, please see the complete development history included as Exhibit C.

11. NERC must explain any balancing of vital public interests in the development of proposed Reliability Standards.[13]

NERC and SERC have not identified competing vital public interests with respect to the request for approval of the regional Reliability Standard, and no comments were received during the development of the regional Reliability Standard indicating conflicts with other vital public interests.

12. Proposed Reliability Standards must consider any other appropriate factors.[14]

No other factors relevant to whether the proposed regional Reliability Standard is just and reasonable were identified.

[13] Order No. 672 at P 335.
[14] Order No. 672 at P 323.

The proposed regional Reliability Standard was developed in accordance with NERC's and SERC's Commission-approved processes for developing and approving Reliability Standards. SERC develops regional Reliability Standards in accordance with the SERC regional Standards Development Procedure. The development process is open to any person who is an interested stakeholder. For more detail, please see the complete development history included as Exhibit C.

11. NERC must explain any balancing of vital public interests in the development of proposed Reliability Standards.[13]

NERC and SERC have not identified competing vital public interests with respect to the request for approval of the regional Reliability Standard, and no comments were received during the development of the regional Reliability Standard indicating conflicts with other vital public interests.

12. Proposed Reliability Standards must consider any other appropriate factors.[14]

No other factors relevant to whether the proposed regional Reliability Standard is just and reasonable were identified.

---

[13] Order No. 672 at P 335. Finally, we understand that at times development of a proposed Reliability Standard may require that a particular reliability goal must be balanced against other vital public interests, such as environmental, social and other goals. We expect the ERO to explain any such balancing in its application for approval of a proposed Reliability Standard.

[14] Order No. 672 at P 323. In considering whether a proposed Reliability Standard is just and reasonable, we will consider the following general factors, as well as other factors that are appropriate for the particular Reliability Standard proposed.

Exhibit C

Summary of Development History and Complete Record of Development

Summary of Development History

Summary of Development History

The development record for proposed regional Reliability Standard PRC-006-SERC-02 is summarized below.

I. Overview of the SERC Engineering Committee Dynamics Review Subcommittee

When evaluating a proposed Reliability Standard, the Commission is expected to give "due weight" to the technical expertise of the ERO.[1] For proposed regional Reliability Standard PRC-006-SERC-02, the technical expertise of the ERO is derived from the SERC Engineering Committee Dynamics Review Subcommittee that conducted the five-year periodic review of PRC-006-SERC-01.[2] A roster of the SERC Engineering Committee Dynamics Review Subcommittee members is included in Exhibit D.

II. Standard Development History

A. Five-year Periodic Review

SERC conducted a five-year periodic review of PRC-006-SERC-01 in accordance with the SERC regional Standards Development Procedure. The SERC Engineering Committee Dynamics Review Subcommittee recommended the proposed revisions in PRC-006-SERC-02 as a result of this review.

B. Initial Comment Period and Ballot

The SERC Standards Committee posted proposed regional Reliability Standard PRC-006-SERC-02 for comment from October 25, 2016 through December 7, 2016. SERC received comments from seven individuals. SERC posted proposed regional Reliability Standard PRC-006-SERC-02 for initial ballot from March 16, 2017 through April 12, 2017. SERC received one

[1] Section 215(d)(2) of the Federal Power Act; 16 U.S.C. §824(d) (2) (2012).

[2] The SERC Regional Standards Development Procedure is available at http://serc1.org/docs/default-source/program-areas/standards-regional-criteria/standards-documents/serc-da-exhibit-c---regional-standards-development-procedure-(6-12-12).pdf?sfvrsn=9079681a_8.

comment during the initial ballot. Based on the comments received, the SERC Engineering Committee Dynamics Review Subcommittee determined to make non-substantive changes to the proposed standard.[3]

C. Final Ballot and SERC Board of Directors Approval

Proposed regional Reliability Standard PRC-006-SERC-02 received 100 percent affirmative votes from SERC stakeholders participating in the final ballot on May 10, 2017. The SERC Board Executive Committee, by delegated authority from the SERC Board of Directives, approved the standard on June 28, 2017.

D. NERC Comment Period and Board of Trustees Approval

NERC posted proposed regional Reliability Standard PRC-006-SERC-02 for a 45-day public comment period from June 9, 2017 to July 24, 2017.[4] The NERC Board of Trustees adopted proposed regional Reliability Standard PRC-006-SERC-02 on August 10, 2017.[5]

---

[3] The Consideration of Comments for the Initial Comment Period and Ballot is available at http://serc1.org/docs/default-source/program-areas/standards-regional-criteria/regional-criteria-and-guidelines/posted-for-ballot/consideration-of-comments-document-prc-006-serc-02-06-12-17-final.pdf?sfvrsn=df1bbac0_2.

[4] The NERC web page for Regional Reliability Standards Under Development is available at http://www.nerc.com/pa/Stand/Pages/RegionalReliabilityStandardsUnderDevelopment.aspx.

[5] NERC, *Board of Trustees Agenda Package*, Agenda Item 9d (PRC-006-SERC-02 Automatic Underfrequency Load Shedding Requirements), *available at* http://www.nerc.com/gov/bot/Agenda%20highlights%20and%20Mintues%202013/Board_Open_Meeting_August_10_2017_Agenda_Package_v2%20(002).pdf.

Complete Record of Development

SERC Reliability Corporation (SERC)		
PRC-006-SERC-02	Automatic Underfrequency Load Shedding Requirements	PRC-006-SERC-02 Clean **(1)** | Redline **(2)** SERC Ballot Results **(3)** SERC Consideration of Comments Form **(4)** Info **(5)** Submit Comments Unofficial Comment Form (Word) **(6)** Comments Received **(7)**

Effective Date

Effective for SERC Region applicable Registered Entities on the first day of the first calendar quarter after approved by FERC

Introduction

1. **Title:** Automatic Underfrequency Load Shedding Requirements

2. **Number:** PRC-006-SERC–02

3. **Purpose:** To establish consistent and coordinated requirements for the design, implementation, and analysis of automatic underfrequency load shedding (UFLS) programs among all SERC applicable entities.

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** Generator Owners

5. **Background**

   The SERC UFLS Standard: PRC-006-SERC-01 ("SERC UFLS Standard") was developed to provide regional UFLS requirements to entities in SERC. UFLS requirements have been in place at a continent-wide level and within SERC for many years prior to implementation of federally mandated reliability compliance standards in 2007.

   When reliability standards were implemented in 2007, the Federal Energy Regulatory Commission ("FERC"), which is the government body with regulatory responsibility for electric reliability, issued FERC Order 693, recognizing 83 NERC Reliability Standards as enforceable by FERC and applicable to users, owners, and operators of the bulk power system (BPS). FERC did not approve the NERC UFLS standard, PRC-006-0 in Order 693. FERC's reason for not approving PRC-006-0 was that it recognized PRC-006-0 as a "fill-in the blank standard," and regional procedures associated with the standard were not submitted along with the standard. FERC's ruling in Order 693 required Regional Entities to provide the regional requirements necessary for completing the UFLS standard.

   In 2008, SERC commenced work on PRC-006-SERC-01. NERC also began work on revising PRC-006-0 at a continent-wide level. The SERC standard has been developed to be consistent with the NERC UFLS standard. PRC-006-SERC-02 was developed per periodic review of the standard.

   PRC-006-1 clearly defines the roles and responsibilities of parties to whom the standard applies. The standard identifies the Planning Coordinator ("PC") as the entity responsible for developing UFLS schemes within their PC area. The regional standard adds specificity not contained in the NERC standard for development and implementation of a UFLS scheme in the SERC Region that effectively mitigates the consequences of an underfrequency event.

Requirements and Measures

R1. Each Planning Coordinator shall include its SERC subregion as an identified island in the criteria (required by the NERC PRC standard on UFLS) for selecting portions of the BPS that may form islands. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1 A Planning Coordinator may adjust island boundaries to differ from subregional boundaries where necessary for the sole purpose of producing a contiguous subregional island more suitable for simulation.

M1. Each Planning Coordinator shall have evidence such as a methodology, procedure, report, or other documentation indicating that its criteria included selection of its SERC subregion(s) as an island per Requirement R1.

R2. Each Planning Coordinator shall select or develop an automatic UFLS scheme (percent of load to be shed, frequency set points, and time delays) for implementation by UFLS entities within its area that meets the following minimum requirements: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. Have the capability of shedding at least 30 percent of the Peak Demand (MW) served from the Planning Coordinator's transmission system. The Peak Demand may be either summer or winter as determined by the Planning Coordinator.

2.2. Shed load with a minimum of three frequency set points.

2.3. The highest frequency set point for relays used to arrest frequency decline shall be no lower than 59.3 Hz and not higher than 59.5 Hz.

2.3.1 This does not apply to UFLS relays with time delay of one second or longer and a higher frequency setpoint applied to prevent the frequency from stalling at less than 60 Hz when recovering from an underfrequency event.

2.4. The lowest frequency set point shall be no lower than 58.4 Hz.

2.5. The difference between frequency set points shall be at least 0.2 Hz but no greater than 0.5 Hz.

2.6. Time delay (from frequency reaching the set point to the trip signal) shall be at least six cycles.

M2. Each Planning Coordinator shall have evidence such as reports or other documentation that the UFLS scheme for its area meets the design requirements specified in Requirement R2.

R3. Each Planning Coordinator, when performing design assessments specified in the NERC PRC standard on UFLS, shall conduct simulations of its UFLS scheme for an imbalance between load and generation of 13%, 22%, and 25% for all identified island(s) where such imbalance equals [(load minus actual generation output) / load]. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M3. Each Planning Coordinator shall have evidence such as reports or other documentation that it performed the simulations of its UFLS scheme as required in Requirement R3.

R4. Each UFLS entity that has a total load of 100 MW or greater in a Planning Coordinator area in the SERC Region shall implement the UFLS scheme developed by their Planning Coordinator. UFLS entities may implement the UFLS scheme developed by the Planning Coordinator by coordinating with other UFLS entities. The UFLS scheme shall meet the following requirements on May 1 of each calendar year. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1. The percent of load shedding to be implemented shall be based on the actual or estimated substation or feeder demand (including losses) of the UFLS entities at the time coincident with the previous year's actual Peak Demand in the season specified by the Planning Coordinator in R2.

4. 2. The amount of load in each load shedding step shall be within -1.0 and +3.0 of the percentage specified by the Planning Coordinator (for example, if the specified percentage step load shed is 12%, the allowable range is 11 to 15%).

4. 3. The amount of total UFLS load of all steps combined shall be within -1.0 and +5.0 of the percentage specified by the Planning Coordinator for the total UFLS load in the UFLS scheme.

M4. Each UFLS entity that has a total load of 100 MW or greater in a Planning Coordinator area in the SERC Region shall have evidence such as reports or other documentation demonstrating that its implementation of the UFLS scheme on May 1 of each calendar year meets the requirements of Requirement R4 (including all the data elements in Parts 4.1, 4.2, and 4.3) unless scheme changes per Requirement R6 are in process.

R5. Each UFLS entity that has a total load less than 100 MW in a Planning Coordinator area in the SERC Region shall implement the UFLS scheme developed by their Planning Coordinator, but shall not be required to have more than one UFLS step. UFLS entities may implement the UFLS scheme developed by the Planning Coordinator by coordinating with other UFLS entities. The UFLS scheme shall meet the following requirements on May 1 of each calendar year. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning].*

5.1. The percent of load shedding to be implemented shall be based on the actual or estimated substation or feeder demand (including losses) of the UFLS entities at the time coincident with the previous year actual Peak Demand in the season specified by the Planning Coordinator in R2..

5.2. The amount of total UFLS load shall be within ± 5.0 of the percentage specified by the Planning Coordinator for the total UFLS load in the UFLS scheme.

M5. Each UFLS entity that has a total load less than 100 MW in a Planning Coordinator area in the SERC Region shall have evidence such as reports or other documentation demonstrating that its implementation of the UFLS scheme on May 1 of each calendar year meets the requirements of Requirement R5 (including all the data elements in Parts 5.1and 5.2) unless scheme changes per Requirement R6 are in process.

R6. Each UFLS entity shall implement changes to the UFLS scheme which involve frequency settings, relay time delays, changes to the percentage of load in the scheme, or changes to the peak season selected in R2.1 within 18 months of notification by the Planning Coordinator. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M6. Each UFLS entity shall have evidence such as reports or other documentation demonstrating that it has made the appropriate scheme changes within 18 months per Requirement R6. Such evidence is only required if the Planning Coordinator makes changes to the UFLS scheme as specified in Requirement R6.

R7. Each Planning Coordinator shall provide the following information to SERC according to the schedule specified by SERC. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

7.1. Underfrequency trip set points (Hz)

7.2. Total clearing time associated with each set point (sec). This includes the time from when frequency reaches the set point and ends when the breaker opens.

7.3. Amount of previous year actual or estimated load associated with each set point, both in percent and in MW. The percentage and the Load demand (MW) shall be based on the time coincident with the previous year actual Peak Demand.

M7. Each Planning Coordinator shall have evidence such as reports or other documentation that data specified in Requirement R7 was provided to SERC in accordance with the schedule.

R8. Each Generator Owner shall provide the following information within 30 days of a request by SERC to facilitate post-event analysis of frequency disturbances. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

8.1. Generator protection automatic underfrequency and overfrequency trip set points (Hz).

8.2. Total clearing time associated with each set point (sec). This is defined as the time that begins when frequency reaches the set point and ends when the breaker opens. If inverse time underfrequency relays are used, provide the total clearing time at 59.0, 58.5, 58.0, and 57.0 Hz.

8.3. Maximum generator net MW that could be tripped automatically due to an underfrequency or overfrequency condition.

M8. Each Generator Owner shall have evidence such as reports or other documentation that data specified in Requirement R8 was provided to SERC as requested.

Compliance

Compliance enforcement authority

SERC Reliability Corporation

Compliance monitoring and assessment process

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaint

Evidence retention

Each Planning Coordinator, UFLS Entity and Generator Owner shall keep data or evidence to show compliance as identified below unless directed by SERC to retain specific evidence for a longer period of time as part of an investigation.

Each Planning Coordinator, UFLS Entity and Generator Owner shall retain the current evidence of each Requirement and Measure as well as any evidence necessary to show compliance since the last compliance audit.

If a Planning Coordinator, UFLS Entity or Generator Owner 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.

Time Horizons, Violation Risk Factors, and Violation Severity Levels

Table 1						
R#	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
R1	Long-term Planning	Medium	N/A	N/A	N/A	The Planning Coordinator did not have evidence that its criteria included selection of its SERC subregion(s) as an island, with or without adjusted boundaries.
R2	Long-term Planning	Medium	The Planning Coordinator's scheme did not meet one of the UFLS system design requirements identified in 2.2 through 2.6	The Planning Coordinator's scheme did not meet two of the UFLS system design requirements identified in 2.2 through 2.6.	The Planning Coordinator's scheme did not meet three of the UFLS system design requirements identified in 2.2 through 2.6.	The Planning Coordinator's scheme did not meet 2.1 **OR** Four or more of the UFLS system design requirements identified in 2.2 through 2.6.
R3	Long-term Planning	High	N/A	The Planning Coordinator failed to conduct one of the required simulations of its UFLS scheme.	N/A	The Planning Coordinator failed to conduct two of the required simulations of its UFLS scheme.
R4	Operations Planning	Medium	The UFLS entity's implemented UFLS scheme had one load shedding step outside the range specified in 4.	The UFLS entity's implemented UFLS scheme had two load shedding steps outside the range specified in 4.	The UFLS entity's implemented UFLS scheme had three or more load shedding steps outside the range	The UFLS entity's implemented UFLS scheme had three or more load shedding steps outside the range

Table 1						
R#	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
			2.	2.	specified in 4.2. **OR** The UFLS entity's implemented UFLS scheme had a total load outside the range specified in 4.3.	specified in 4.2. **AND** The UFLS entity's implemented UFLS scheme had a total load outside the range specified in 4.3.
R5	Operations Planning	Medium	N/A	N/A	N/A	The UFLS entity's implemented UFLS scheme had a total load outside the range specified in 5.2.
R6	Long-term Planning	High	The UFLS entity implemented required scheme changes but made them 1 to 30 days after the scheduled date.	The UFLS entity implemented required scheme changes but made them 31 to 40 days after the scheduled date.	The UFLS entity implemented required scheme changes but made them 41 to 50 days after the scheduled date.	The UFLS entity implemented required scheme changes but made them more than 50 days after the scheduled date OR The UFLS entity failed to implement the required scheme changes.
R7	Long-term Planning	Lower	The Planning Coordinator provided the data required in R7 to SERC 1 to 10 days	The Planning Coordinator provided the data required in R7 to SERC 11 to 20 days	The Planning Coordinator provided the data required in R7 to SERC 21 to 30 days	The Planning Coordinator provided the data required in R7 to SERC more than 30

Table 1						
R#	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
			after the scheduled submittal date.	after the scheduled submittal date. **OR** The Planning Coordinator did not provide to SERC one piece of information listed in R7.	after the scheduled submittal date. **OR** The Planning Coordinator did not provide to SERC two pieces of information listed in R7.	days after the scheduled submittal date. **OR** The Planning Coordinator did not provide to SERC any of the information listed in R7.
R8	Long-term Planning	Lower	The Generator Owner provided the data required in R8 to SERC 1 to 10 days after the requested submittal date.	The Generator Owner provided the data required in R8 to SERC 11 to 20 days after the requested submittal date. **OR** The Generator Owner did not provide to SERC one piece of information listed in R8.	The Generator Owner provided the data required in R8 to SERC 21 to 30 days after the requested submittal date. **OR** The Generator Owner did not provide to SERC two pieces of information listed in R8.	The Generator Owner provided the data required in R8 to SERC more than 30 days after the requested submittal date. **OR** The Generator Owner did not provide to SERC any of the information listed in R8.

Regional Variances

None

Interpretations

None

Guideline and Technical Basis

1. **Existing UFLS schemes**
   Each Planning Coordinator should consider the existing UFLS programs which are in place and should consider input from the UFLS entities in developing the UFLS scheme.

2. **Basis for SERC standard requirements**
   SERC Standard PRC-006-SERC-02 is not a stand-alone standard, but was written to be followed in conjunction with NERC Standard PRC-006-1. The primary focus of SERC Standard PRC-006-SERC-02 was to provide region-specific requirements for the implementation of the higher tier NERC standard requirements with the goals of a) adding clarity and b) providing for consistency and a coordinated UFLS scheme for the SERC Region as a whole.
   Generally speaking, requirements already in the NERC standard were not repeated in the SERC standard. Therefore, both the NERC and SERC standards must be followed to ensure full compliance.

3. **Basis for applying a percentage load shedding value to Forecast Load versus Actual Load**
   The Planning Coordinator will develop a UFLS scheme to meet the performance requirements of NERC Standard PRC-006-2 Requirement R3 and SERC Standard PRC-006-SERC-02 Requirement R2. This development will result in certain percentages of load for each UFLS entity in the Planning Coordinator's area for which automatic under frequency load shedding must be implemented. The Planning Coordinator develops these percentages based on forecast peak load demand. However, the UFLS entity implements these percentages based on the previous year's actual peak demand. Applying the same percentage to these different base values was intentional to ensure that both the Planning Coordinator and UFLS entities had a clear, measurable value to use in performing their respective roles in meeting the standard. Planning Coordinators typically use forecast demands in their work. Whereas the previous year's actual (or estimated) demand is typically more available to UFLS entities. Additionally, the use of percentages based on these different base values tends to minimize the error due to the time lag between design and actual field implementation. Since a percentage is provided by the Planning Coordinator to the UFLS entities, any differences between the design values (i.e., forecast load) and the implemented values (i.e., previous year's actual) would naturally tend to match up reasonably well. For example, if the total planning area load in MW for which UFLS was installed during the time of implementation was slightly higher or lower than the MW value used in the design by the Planning Coordinator, multiplying by the specified percentage would result in an implemented load shedding scheme that also had a reasonably similar higher or lower MW value.

4. **Basis for May 1 and 18 month time frames**
   Each UFLS entity must annually review that the amount of UFLS load shedding implemented is within a certain tolerance as specified by SERC Standard PRC-006-SERC-02 Requirement R 4 or Requirement R5 by May 1 of the current year. May 1 was chosen to allow sufficient time after the previous year's peak occurred to make adjustments in the field to the implementation if necessary to meet the tolerances specified in Requirement R4 or Requirement R5. Therefore, the May 1 date applies only to implementation of the existing percentages of load shedding specified by the Planning Coordinator. On the other hand, the 18-month time frame specified in PRC-006-SERC-02 Requirement R6 is intended to allow sufficient budgeting, procurement, and installation time for additional equipment, or for significant setting changes to existing equipment necessary to meet a revised load shedding scheme design that has been specified by the Planning Coordinator. During this 18-month transition period, the May 1 measurement of R4 or Requirement R5 would not apply.

5. **Basis for smaller entity threshold of 100 MW**
   Most distribution substations have transformers rated in the range of 10 to 40 MVA. Usually most transformers would serve 1 to 4 feeders and each feeder will normally carry between 8 and 10 MVA. In general, assuming that each feeder would carry 10 MW, an entity with a load slightly greater than 100 MW would have at least 10 feeders available. For a program with three 10 % steps, only 3 feeders would be required to have under frequency load shed capabilities. The 100 MW threshold seems to provide adequate flexibility for implementing load shedding in three steps for entities slightly greater than 100 MW.

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 each of the rationale text boxes was moved to this section.

Rationale for R1:

Studying the Region as an island is required by the NERC standard. Most regions have only one or a few different UFLS schemes. Where there is more than one scheme, studying this island demonstrates that the schemes are coordinated and performing adequately. Because there are so many different UFLS schemes in SERC (18 different schemes were represented in the 2007 SERC UFLS study), the SDT believes that applying the schemes to each subregion as an island is a necessary additional test of the coordination of the various UFLS schemes. Without this additional test, a poorly performing scheme may be masked by the large number of good performing schemes in the Region. A subregion island study, which would have a smaller number of schemes, would be more likely to uncover the poorly performing scheme and therefore get it fixed. This approach will result in a much better overall performance of the UFLS programs in SERC. The SDT recognized that there may be simulation problems due to opening the ties to utilities outside the subregion. Therefore, the subregion island boundaries are allowed to be adjusted to produce an island more suitable for simulation.

(Note: The SERC Subregions are identified in paragraph 4.2 of the SERC Reliability Corporation Bylaws: "The Region is currently geographically divided into five subregions that are identified as Southeastern, Central, VACAR, Delta, and Gateway.")

Rationale for R2:
These requirements for the UFLS schemes in SERC have been in place for many years (except 2.6). The SDT believes that these requirements are still needed to ensure consistency for the various schemes which are used in SERC. Part 2.6 is designed to prevent spurious operations due to transient frequency swings.

Rationale for R3:
R4 of the NERC standard PRC-006-1 requires the PC to conduct assessments of UFLS schemes through dynamic simulations to verify that they meet performance requirements for generation/load imbalances of up to 25%. This requirement defines specific imbalances that are to be studied within SERC. The 13% and 22% levels were determined from simulations of the worst case frequency overshoot for the UFLS schemes in SERC.

Rationale for R4:
The SDT believes it is necessary to put a requirement on how well the UFLS scheme is implemented. This requirement specifies how close the actual load shedding amounts must be to the percentage of load called for in the scheme. A 4 percentage point range is allowed for each individual step, but the allowed range for all steps combined is 6 percentage points.

Rationale for R5:
The SDT believes it is necessary to put a requirement on how well the UFLS scheme is implemented. This requirement specifies how close the actual load shedding amounts must be to the percentage of load called for in the scheme. The SDT recognizes that UFLS entities with a load of less than 100 MW may have difficulty in implementing more than one UFLS step and in meeting a tight tolerance. The basis of the 100 MW comes from typical feeder load dropped by UFLS relays, and the use of a 100 MW threshold in other regional UFLS standards.

Rationale for R6:
The SDT believes it is necessary to put a requirement on how quickly changes to the scheme should be implemented. This requirement specifies that changes must be implemented within 18 months of notification by the PC. The 18 month interval was chosen to give a reasonable amount of time for making changes in the field. All of the SERC Region has existing UFLS schemes which, based on periodic simulations, have provided reliable protection for years. Events which result in islanding and an activation of the UFLS schemes are extremely rare in SERC. Therefore, the SDT does not believe that changes to an existing UFLS scheme will be needed in less than 18 months. However, if a PC determines there is a need for changing the UFLS scheme faster than 18 months, then the PC may require the implementation to be done sooner as allowed by NERC Reliability Standard PRC-006-1.

Rationale for R7:
The NERC standard requires that a UFLS database be maintained by the Planning Coordinator. This requirement specifies what data must be reported to SERC. A SERC UFLS database is needed to facilitate data sharing across the SERC Region, with other regions, and with NERC.

Rationale for R8:
The SDT believes that generator over and under frequency tripping data is needed to supplement the UFLS data provided by the Planning Coordinator for post-event analysis of frequency disturbances. This requirement states what data must be reported to SERC by the Generator Owners.

Since the inverse time curve cannot easily be placed into the SERC database, four clearing times based on data from the curve are requested. These clearing times are intended to cover a range of frequencies needed for event replication as well as provide information about generators that trip at a higher frequency than is allowed by the NERC standard.

Version History

Version	Date	Action	Change Tracking
1	September 19, 2011	SERC Board Approved	
1	November 3, 2011	Adopted by NERC Board of Trustees	
1	December 20, 2012	FERC Order issued approving PRC-006-SERC–01	
1	March 11, 2013	Modified the Rationale and changed the VRF for Requirement R6 from “Medium” to “High” per a compliance filing (Filed on 3/11/13)	
2	June 28, 2017	SERC Board Approved	
2	August 10, 2017	Adopted by NERC Board of Trustees	

*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard PRC-006-SERC-02 — Automatic Underfrequency Load Shedding Requirements

United States

Standard	Requirement	Enforcement Date	Inactive Date
PRC-006-SERC-02	All	TBD	

Effective Dates

Effective for SERC Region applicable Registered Entities on the first day of the first calendar quarter after approved by FERC

Requirement	Jurisdiction									
	Alberta	British Columbia	Manitoba	New Brunswick	Newfound-land	Nova Scotia	Ontario	Quebec	Saskatch-ewan	USA
R1	NA	NA	NA	NA	NA	NA	NA	NA	NA	4/1/14
R2	NA	NA	NA	NA	NA	NA	NA	NA	NA	4/1/14
R3	NA	NA	NA	NA	NA	NA	NA	NA	NA	10/1/14
R4, R5, and R6	NA	NA	NA	NA	NA	NA	NA	NA	NA	10/1/15
R7	NA	NA	NA	NA	NA	NA	NA	NA	NA	4/1/14
R8	NA	NA	NA	NA	NA	NA	NA	NA	NA	4/1/14

Requirement R1 shall become effective 12 months after the first day of the first quarter following regulatory approval, but no sooner than 12 months following regulatory approval of NERC PRC-006-1. This 12-month period is consistent with the effective date of R2 of PRC-006-1.

Requirement R2 shall become effective 12 months after the first day of the first quarter following regulatory approval. This 12-month period is needed to allow time for entities to ensure a minimum time delay of six cycles on existing UFLS relays as specified in part 2.6.

~~Requirements R3 shall become effective 18 months after the first day of the first quarter following regulatory approval. This additional six-month period is needed to allow time to perform and coordinate studies necessary to assess the overall effectiveness of the UFLS schemes in the SERC Region.~~

~~Requirements R4, R5, and R6 shall become effective 30 months after the first day of the first quarter following regulatory approval. This additional 18 months is needed to allow time for any necessary changes to be made to the existing UFLS schemes in the SERC Region.~~

~~Requirement R7 shall become effective six months following the effective date of R8 of the NERC standard PRC-006-1, but no sooner than one year following the first day of the first calendar quarter after applicable regulatory approval of PRC-006-SERC-01. R8 of the NERC standard requires each UFLS entity to provide UFLS data to the Planning Coordinator (PC). R7 of the SERC standard requires the PC to provide this data to SERC.~~

~~Requirement R8 shall become effective 12 months after the first day of the first quarter following regulatory approval. This 12-month period is needed to allow time for Generator Owners (GO) to collect and make an initial data filing.~~

Introduction

1. **Title:** Automatic Underfrequency Load Shedding Requirements

2. **Number:** PRC-006-SERC–0~~1~~2

3. **Purpose:** To establish consistent and coordinated requirements for the design, implementation, and analysis of automatic underfrequency load shedding (UFLS) programs among all SERC applicable entities.

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** Generator Owners

5. **Background**

The SERC UFLS Standard: PRC-006-SERC-01 ("SERC UFLS Standard") was developed to provide regional UFLS requirements to entities in SERC. UFLS requirements have been in place at a continent-wide level and within SERC for many years prior to implementation of federally mandated reliability compliance standards in 2007.

When reliability standards were implemented in 2007, the Federal Energy Regulatory Commission ("FERC"), which is the government body with regulatory responsibility for electric reliability, issued FERC Order 693, recognizing 83 NERC Reliability Standards as enforceable by FERC and applicable to users, owners, and operators of the bulk power system (BPS). FERC did not approve the NERC UFLS standard, PRC-006-0 in Order 693. FERC's reason for not approving PRC-006-0 was that it recognized PRC-006-0 as a "fill-in the blank standard," and regional procedures associated with the standard were not submitted along with the standard. FERC's ruling in Order 693 required Regional Entities to provide the regional requirements necessary for completing the UFLS standard.

In 2008, SERC commenced work on PRC-006-SERC-01. NERC also began work on revising PRC-006-0 at a continent-wide level. The SERC standard has been developed to be consistent with the NERC UFLS standard. PRC-006-SERC-02 was developed per periodic review of the standard.

PRC-006-1 clearly defines the roles and responsibilities of parties to whom the standard applies. The standard identifies the Planning Coordinator ("PC") as the entity responsible for developing UFLS schemes within their PC area. The regional standard adds specificity not contained in the NERC standard for development and implementation of a UFLS scheme in the SERC Region that effectively mitigates the consequences of an underfrequency event.

Requirements and Measures

R1. Each Planning Coordinator shall include its SERC subregion as an identified island in the criteria (required by the NERC PRC standard on UFLS) for selecting portions of the BPS that may form islands. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1 A Planning Coordinator may adjust island boundaries to differ from subregional boundaries where necessary for the sole purpose of producing a contiguous subregional island more suitable for simulation.

M1. Each Planning Coordinator shall have evidence such as a methodology, procedure, report, or other documentation indicating that its criteria included selection of its SERC subregion(s) as an island per Requirement R1.

R2. Each Planning Coordinator shall select or develop an automatic UFLS scheme (percent of load to be shed, frequency set points, and time delays) for implementation by UFLS entities within its area that meets the following minimum requirements: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. Have the capability of shedding at least 30 percent of the Peak Demand (MW) served from the Planning Coordinator's transmission system. The Peak Demand may be either summer or winter as determined by the Planning Coordinator.

2.2. Shed load with a minimum of three frequency set points.

2.3. The highest frequency set point for relays used to arrest frequency decline shall be no lower than 59.3 Hz and not higher than 59.5 Hz.

2.3.1 This does not apply to UFLS relays with time delay of one second or longer and a higher frequency setpoint applied to prevent the frequency from stalling at less than 60 Hz when recovering from an underfrequency event.

2.4. The lowest frequency set point shall be no lower than 58.4 Hz.

2.5. The difference between frequency set points shall be at least 0.2 Hz but no greater than 0.5 Hz.

2.6. Time delay (from frequency reaching the set point to the trip signal) shall be at least six cycles.

M2. Each Planning Coordinator shall have evidence such as reports or other documentation that the UFLS scheme for its area meets the design requirements specified in Requirement R2.

R3. Each Planning Coordinator, when performing design assessments specified in the NERC PRC standard on UFLS, shall conduct simulations of its UFLS scheme for an imbalance between load and generation of 13%, 22%, and 25% for all identified island(s) where such imbalance equals [(load minus actual generation output) / load]. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M3. Each Planning Coordinator shall have evidence such as reports or other documentation that it performed the simulations of its UFLS scheme as required in Requirement R3.

R4. Each UFLS entity that has a total load of 100 MW or greater in a Planning Coordinator area in the SERC Region shall implement the UFLS scheme developed by their Planning Coordinator. UFLS entities may implement the UFLS scheme developed by the Planning Coordinator by coordinating with other UFLS entities. The UFLS scheme shall meet the following requirements on May 1 of each calendar year. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1. The percent of load shedding to be implemented shall be based on the actual or estimated ~~distribution~~ substation or feeder demand (including losses) of the UFLS entities at the time coincident with the previous year's actual Peak Demand in the season specified by the Planning Coordinator in R2.

4. 2. The amount of load in each load shedding step shall be within -1.0 and +3.0 of the percentage specified by the Planning Coordinator (for example, if the specified percentage step load shed is 12%, the allowable range is 11 to 15%).

4. 3. The amount of total UFLS load of all steps combined shall be within -1.0 and +5.0 of the percentage specified by the Planning Coordinator for the total UFLS load in the UFLS scheme.

M4. Each UFLS entity that has a total load of 100 MW or greater in a Planning Coordinator area in the SERC Region shall have evidence such as reports or other documentation demonstrating that its implementation of the UFLS scheme on May 1 of each calendar year meets the requirements of Requirement R4 (including all the data elements in Parts 4.1, 4.2, and 4.3) unless scheme changes per Requirement R6 are in process.

R5. Each UFLS entity that has a total load less than 100 MW in a Planning Coordinator area in the SERC Region shall implement the UFLS scheme developed by their Planning Coordinator, but shall not be required to have more than one UFLS step. UFLS entities may implement the UFLS scheme developed by the Planning Coordinator by coordinating with other UFLS entities. The UFLS scheme shall meet the following requirements on May 1 of each calendar year. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning].*

5.1. The percent of load shedding to be implemented shall be based on the actual or estimated ~~distribution~~ substation or feeder demand (including losses) of the UFLS entities at the time coincident with the previous year actual Peak Demand in the season specified by the Planning Coordinator in R2.

5.2. The amount of total UFLS load shall be within ± 5.0 of the percentage specified by the Planning Coordinator for the total UFLS load in the UFLS scheme.

M5. Each UFLS entity that has a total load less than 100 MW in a Planning Coordinator area in the SERC Region shall have evidence such as reports or other documentation demonstrating that its implementation of the UFLS scheme on May 1 of each calendar year meets the requirements of Requirement R5 (including all the data elements in Parts 5.1and 5.2) unless scheme changes per Requirement R6 are in process.

R6. Each UFLS entity shall implement changes to the UFLS scheme which involve frequency settings, relay time delays, ~~or~~ changes to the percentage of load in the scheme, or changes to the peak season selected in R2.1 within 18 months of notification by the Planning Coordinator. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M6. Each UFLS entity shall have evidence such as reports or other documentation demonstrating that it has made the appropriate scheme changes within 18 months per Requirement R6. Such evidence is only required if the Planning Coordinator makes changes to the UFLS scheme as specified in Requirement R6.

R7. Each Planning Coordinator shall provide the following information to SERC according to the schedule specified by SERC. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

7.1. Underfrequency trip set points (Hz)

7.2. Total clearing time associated with each set point (sec). This includes the time from when frequency reaches the set point and ends when the breaker opens.

7.3. Amount of previous year actual or estimated load associated with each set point, both in percent and in MW. The percentage and the Load demand (MW) shall be based on the time coincident with the previous year actual Peak Demand.

M7. Each Planning Coordinator shall have evidence such as reports or other documentation that data specified in Requirement R7 was provided to SERC in accordance with the schedule.

R8. Each Generator Owner shall provide the following information within 30 days of a request by SERC to facilitate post-event analysis of frequency disturbances. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

8.1. Generator protection automatic underfrequency and overfrequency trip set points (Hz).

8.2. Total clearing time associated with each set point (sec). This is defined as the time that begins when frequency reaches the set point and ends when the breaker opens. If inverse time underfrequency relays are used, provide the total clearing time at 59.0, 58.5, 58.0, and 57.0 Hz.

8.3. Maximum generator net MW that could be tripped automatically due to an underfrequency or overfrequency condition.

M8. Each Generator Owner shall have evidence such as reports or other documentation that data specified in Requirement R8 was provided to SERC as requested.

Compliance

Compliance enforcement authority

SERC Reliability Corporation

Compliance monitoring and assessment process

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaint

Evidence retention

Each Planning Coordinator, UFLS Entity and Generator Owner shall keep data or evidence to show compliance as identified below unless directed by SERC to retain specific evidence for a longer period of time as part of an investigation.

Each Planning Coordinator, UFLS Entity and Generator Owner shall retain the current evidence of each Requirement and Measure as well as any evidence necessary to show compliance since the last compliance audit.

If a Planning Coordinator, UFLS Entity or Generator Owner 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.

Time Horizons, Violation Risk Factors, and Violation Severity Levels

Table 1						
R#	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
R1	Long-term Planning	Medium	N/A	N/A	N/A	The Planning Coordinator did not have evidence that its criteria included selection of its SERC subregion(s) as an island, with or without adjusted boundaries.
R2	Long-term Planning	Medium	The Planning Coordinator's scheme did not meet one of the UFLS system design requirements identified in 2.2 through 2.6	The Planning Coordinator's scheme did not meet two of the UFLS system design requirements identified in 2.2 through 2.6.	The Planning Coordinator's scheme did not meet three of the UFLS system design requirements identified in 2.2 through 2.6.	The Planning Coordinator's scheme did not meet 2.1 **OR** Four or more of the UFLS system design requirements identified in 2.2 through 2.6.
R3	Long-term Planning	High	N/A	The Planning Coordinator failed to conduct one of the required simulations of its UFLS scheme.	N/A	The Planning Coordinator failed to conduct two of the required simulations of its UFLS scheme.
R4	Operations Planning	Medium	The UFLS entity's implemented UFLS scheme had one load shedding step outside the range specified in 4.	The UFLS entity's implemented UFLS scheme had two load shedding steps outside the range specified in 4.	The UFLS entity's implemented UFLS scheme had three or more load shedding steps outside the range	The UFLS entity's implemented UFLS scheme had three or more load shedding steps outside the range

Table 1						
R#	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
			2.	2.	specified in 4.2. **OR** The UFLS entity's implemented UFLS scheme had a total load outside the range specified in 4.3.	specified in 4.2. **AND** The UFLS entity's implemented UFLS scheme had a total load outside the range specified in 4.3.
R5	Operations Planning	Medium	N/A	N/A	N/A	The UFLS entity's implemented UFLS scheme had a total load outside the range specified in 5.2.
R6	Long-term Planning	High	The UFLS entity implemented required scheme changes but made them 1 to 30 days after the scheduled date.	The UFLS entity implemented required scheme changes but made them 31 to 40 days after the scheduled date.	The UFLS entity implemented required scheme changes but made them 41 to 50 days after the scheduled date.	The UFLS entity implemented required scheme changes but made them more than 50 days after the scheduled date OR The UFLS entity failed to implement the required scheme changes.
R7	Long-term Planning	Lower	The Planning Coordinator provided the data required in R7 to SERC 1 to 10 days	The Planning Coordinator provided the data required in R7 to SERC 11 to 20 days	The Planning Coordinator provided the data required in R7 to SERC 21 to 30 days	The Planning Coordinator provided the data required in R7 to SERC more than 30

Table 1						
R#	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
			after the scheduled submittal date.	after the scheduled submittal date. **OR** The Planning Coordinator did not provide to SERC one piece of information listed in R7.	after the scheduled submittal date. **OR** The Planning Coordinator did not provide to SERC two pieces of information listed in R7.	days after the scheduled submittal date. **OR** The Planning Coordinator did not provide to SERC any of the information listed in R7.
R8	Long-term Planning	Lower	The Generator Owner provided the data required in R8 to SERC 1 to 10 days after the requested submittal date.	The Generator Owner provided the data required in R8 to SERC 11 to 20 days after the requested submittal date. **OR** The Generator Owner did not provide to SERC one piece of information listed in R8.	The Generator Owner provided the data required in R8 to SERC 21 to 30 days after the requested submittal date. **OR** The Generator Owner did not provide to SERC two pieces of information listed in R8.	The Generator Owner provided the data required in R8 to SERC more than 30 days after the requested submittal date. **OR** The Generator Owner did not provide to SERC any of the information listed in R8.

Regional Variances

None

Interpretations

None

Guideline and Technical Basis

1. **Existing UFLS schemes**
   Each Planning Coordinator should consider the existing UFLS programs which are in place and should consider input from the UFLS entities in developing the UFLS scheme.

2. **Basis for SERC standard requirements**
   SERC Standard PRC-006-SERC-~~01~~ 02 is not a stand-alone standard, but was written to be followed in conjunction with NERC Standard PRC-006-1. The primary focus of SERC Standard PRC-006-SERC-~~01~~ 02 was to provide region-specific requirements for the implementation of the higher tier NERC standard requirements with the goals of a) adding clarity and b) providing for consistency and a coordinated UFLS scheme for the SERC Region as a whole. Generally speaking, requirements already in the NERC standard were not repeated in the SERC standard. Therefore, both the NERC and SERC standards must be followed to ensure full compliance.

3. **Basis for applying a percentage load shedding value to Forecast Load versus Actual Load**
   The Planning Coordinator will develop a UFLS scheme to meet the performance requirements of NERC Standard PRC-006-~~1~~ 2 Requirement R3 and SERC Standard PRC-006-SERC-~~01~~ 02 Requirement R2. This development will result in certain percentages of load for each UFLS entity in the Planning Coordinator's area for which automatic under frequency load shedding must be implemented. The Planning Coordinator develops these percentages based on forecast peak load demand. However, the UFLS entity implements these percentages based on the previous year's actual peak demand. Applying the same percentage to these different base values was intentional to ensure that both the Planning Coordinator and UFLS entities had a clear, measurable value to use in performing their respective roles in meeting the standard. Planning Coordinators typically use forecast demands in their work. Whereas the previous year's actual (or estimated) demand is typically more available to UFLS entities. Additionally, the use of percentages based on these different base values tends to minimize the error due to the time lag between design and actual field implementation. Since a percentage is provided by the Planning Coordinator to the UFLS entities, any differences between the design values (i.e., forecast load) and the implemented values (i.e., previous year's actual) would naturally tend to match up reasonably well. For example, if the total planning area load in MW for which UFLS was installed during the time of implementation was slightly higher or lower than the MW value used in the design by the Planning Coordinator, multiplying by the specified percentage would result in an implemented load shedding scheme that also had a reasonably similar higher or lower MW value.

4. **Basis for May 1 and 18 month time frames**
   Each UFLS entity must annually review that the amount of UFLS load shedding implemented is within a certain tolerance as specified by SERC Standard PRC-006-SERC-~~01~~ 02 Requirement R 4 or Requirement R5 by May 1 of the current year. May 1 was chosen to allow sufficient time after the previous year's peak occurred to make adjustments in the field to the implementation if necessary to meet the tolerances specified in Requirement R4 or Requirement R5. Therefore, the May 1 date applies only to implementation of the existing percentages of load shedding specified by the Planning Coordinator. On the other hand, the 18-month time frame specified in PRC-006-SERC-~~01~~ 02 Requirement R6 is intended to allow sufficient budgeting, procurement, and installation time for additional equipment, or for significant setting changes to existing equipment necessary to meet a revised load shedding scheme design that has been specified by the Planning Coordinator. During this 18-month transition period, the May 1 measurement of R4 or Requirement R5 would not apply.

5. **Basis for smaller entity threshold of 100 MW**
   Most distribution substations have transformers rated in the range of 10 to 40 MVA. Usually most transformers would serve 1 to 4 feeders and each feeder will normally carry between 8 and 10 MVA. In general, assuming that each feeder would carry 10 MW, an entity with a load slightly greater than 100 MW would have at least 10 feeders available. For a program with three 10 % steps, only 3 feeders would be required to have under frequency load shed capabilities. The 100 MW threshold seems to provide adequate flexibility for implementing load shedding in three steps for entities slightly greater than 100 MW.

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 each of the rationale text boxes was moved to this section.

Rationale for R1:

Studying the Region as an island is required by the NERC standard. Most regions have only one or a few different UFLS schemes. Where there is more than one scheme, studying this island demonstrates that the schemes are coordinated and performing adequately. Because there are so many different UFLS schemes in SERC (18 different schemes were represented in the 2007 SERC UFLS study), the SDT believes that applying the schemes to each subregion as an island is a necessary additional test of the coordination of the various UFLS schemes. Without this additional test, a poorly performing scheme may be masked by the large number of good performing schemes in the Region. A subregion island study, which would have a smaller number of schemes, would be more likely to uncover the poorly performing scheme and therefore get it fixed. This approach will result in a much better overall performance of the UFLS programs in SERC. The SDT recognized that there may be simulation problems due to opening the ties to utilities outside the subregion. Therefore, the subregion island boundaries are allowed to be adjusted to produce an island more suitable for simulation.

(Note: The SERC Subregions are identified in paragraph 4.2 of the SERC Reliability Corporation Bylaws: "The Region is currently geographically divided into five subregions that are identified as Southeastern, Central, VACAR, Delta, and Gateway.")

Rationale for R2:
These requirements for the UFLS schemes in SERC have been in place for many years (except 2.6). The SDT believes that these requirements are still needed to ensure consistency for the various schemes which are used in SERC. Part 2.6 is designed to prevent spurious operations due to transient frequency swings.

Rationale for R3:
R4 of the NERC standard PRC-006-1 requires the PC to conduct assessments of UFLS schemes through dynamic simulations to verify that they meet performance requirements for generation/load imbalances of up to 25%. This requirement defines specific imbalances that are to be studied within SERC. The 13% and 22% levels were determined from simulations of the worst case frequency overshoot for the UFLS schemes in SERC.

Rationale for R4:
The SDT believes it is necessary to put a requirement on how well the UFLS scheme is implemented. This requirement specifies how close the actual load shedding amounts must be to the percentage of load called for in the scheme. A 4 percentage point range is allowed for each individual step, but the allowed range for all steps combined is 6 percentage points.

Rationale for R5:
The SDT believes it is necessary to put a requirement on how well the UFLS scheme is implemented. This requirement specifies how close the actual load shedding amounts must be to the percentage of load called for in the scheme. The SDT recognizes that UFLS entities with a load of less than 100 MW may have difficulty in implementing more than one UFLS step and in meeting a tight tolerance. The basis of the 100 MW comes from typical feeder load dropped by UFLS relays, and the use of a 100 MW threshold in other regional UFLS standards.

Rationale for R6:
The SDT believes it is necessary to put a requirement on how quickly changes to the scheme should be implemented. This requirement specifies that changes must be implemented within 18 months of notification by the PC. The 18 month interval was chosen to give a reasonable amount of time for making changes in the field. All of the SERC Region has existing UFLS schemes which, based on periodic simulations, have provided reliable protection for years. Events which result in islanding and an activation of the UFLS schemes are extremely rare in SERC. Therefore, the SDT does not believe that changes to an existing UFLS scheme will be needed in less than 18 months. However, if a PC determines there is a need for changing the UFLS scheme faster than 18 months, then the PC may require the implementation to be done sooner as allowed by NERC Reliability Standard PRC-006-1.

Rationale for R7:
The NERC standard requires that a UFLS database be maintained by the Planning Coordinator. This requirement specifies what data must be reported to SERC. A SERC UFLS database is needed to facilitate data sharing across the SERC Region, with other regions, and with NERC.

Rationale for R8:
The SDT believes that generator over and under frequency tripping data is needed to supplement the UFLS data provided by the Planning Coordinator for post-event analysis of frequency disturbances. This requirement states what data must be reported to SERC by the Generator Owners.

Since the inverse time curve cannot easily be placed into the SERC database, four clearing times based on data from the curve are requested. These clearing times are intended to cover a range of frequencies needed for event replication as well as provide information about generators that trip at a higher frequency than is allowed by the NERC standard.

Version History

Version	Date	Action	Change Tracking
1	September 19, 2011	SERC Board Approved	
1	November 3, 2011	Adopted by NERC Board of Trustees	
1	December 20, 2012	FERC Order issued approving PRC-006-SERC–01	
1	March 11, 2013	Modified the Rationale and changed the VRF for Requirement R6 from “Medium” to “High” per a compliance filing (Filed on 3/11/13)	
2	June 28, 2017	SERC Board Approved	
2	August 10, 2017	Adopted by NERC Board of Trustees	

*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard PRC-006-SERC-~~01~~ 02 — Automatic Underfrequency Load Shedding Requirements

United States

~~Standard~~	~~Requirement~~	~~Effective Date of Standard~~	~~Phased In Implementation Date (if applicable)~~	~~Inactive Date~~
~~PRC-006-SERC-01~~	~~R1.~~	~~04/01/2014~~		
~~PRC-006-SERC-01~~	~~1.1.~~	~~04/01/2014~~		
~~PRC-006-SERC-01~~	~~R2.~~	~~04/01/2014~~		
~~PRC-006-SERC-01~~	~~2.1.~~	~~04/01/2014~~		
~~PRC-006-SERC-01~~	~~2.2.~~	~~04/01/2014~~		
~~PRC-006-SERC-01~~	~~2.3.~~	~~04/01/2014~~		
~~PRC-006-SERC-01~~	~~2.3.1.~~	~~04/01/2014~~		
~~PRC-006-SERC-01~~	~~2.4.~~	~~04/01/2014~~		
~~PRC-006-SERC-01~~	~~2.5.~~	~~04/01/2014~~		
~~PRC-006-SERC-01~~	~~2.6.~~	~~04/01/2014~~		
~~PRC-006-SERC-01~~	~~R3.~~		~~10/01/2014~~	
~~PRC-006-SERC-01~~	~~R4.~~		~~10/01/2015~~	
~~PRC-006-SERC-01~~	~~4.1.~~		~~10/01/2015~~	
~~PRC-006-SERC-01~~	~~4.2.~~		~~10/01/2015~~	
~~PRC-006-SERC-01~~	~~4.3.~~		~~10/01/2015~~	
~~PRC-006-SERC-01~~	~~R5.~~		~~10/01/2015~~	
~~PRC-006-SERC-01~~	~~5.1.~~		~~10/01/2015~~	
~~PRC-006-SERC-01~~	~~5.2.~~		~~10/01/2015~~	

Standard	Requirement	Enforcement Date	Inactive Date
PRC-006-SERC-02	All	TBD	

SERC RELIABILITY CORPORATION

Evaluation | Analysis | Assistance | Operating Experience

May 15, 2017

TO: SERC CIPC Representatives and Alternates
SERC EC Representatives and Alternates
SERC OC Representatives and Alternates
SERC Registered Entity Compliance Contacts

FROM THE DESK OF: David Greene

The Final Ballots for the **SERC Regional Standards Development Procedure** and **PRC-006-SERC-01 Automatic Underfrequency Load Shedding Reliability Standard** have both **concluded** and **both items have passed their final ballots.**

Results:

SERC Regional Standards Development Procedure: (no change from the Initial Ballot)

100% Affirmative Weighted Sector Vote (67% required to pass)

73% of Ballot Members voted (47 of 64, 67% required to pass); 44 Affirmative Votes, 3 Abstain

PRC-006-SERC-01 Automatic Underfrequency Load Shedding: (single Negative vote with Initial Ballot changed to an Affirmative vote)

100% Affirmative Weighted Sector Vote (67% required to pass)

71% of Ballot Members voted (44 of 62, 67% required to pass); 44 Affirmative Votes

Both items will be presented for approval to the SERC Board Executive Committee (BEC) at the June 28, 2017 BEC meeting. Once approved by the SERC BEC, each item will be sent to NERC for approval. Once approved by the NERC Board of Trustees (BOT), each item will be sent to FERC for approval. Once approved by the FERC Commissioners, each item will begin implementation.

Questions may be directed to: David Greene / 704-414-5238

All other questions may be directed to SERC Support.

3701 Arco Corporate Drive, Suite 300, Charlotte, NC 28273 • Office: 704-357-7372 • Fax: 704-357-7914 • www.serc1.org

Consideration of Comments Form

The SERC Standards Committee posted *PRC-006-SERC-02* for comment from October 25, 2016 through December 7, 2016 and posted *PRC-006-SERC-02* for Initial Ballot from March 16, 2017 through April 12, 2017, in accordance with the SERC Regional Standard Development Procedure. *PRC-006-SERC-02* passed Final Ballot on May 10, 2017. This document contains comments and responses from the initial comment posting and Initial Ballot posting.

Background:
FERC approved the SERC Regional Standard - *PRC-006-SERC-01 Automatic Underfrequency Load Shedding (UFLS) Requirements* on December 20, 2012. *PRC-006-SERC-02* incorporates revisions to the standard per its five-year periodic review.

Major Changes to this Revision of the SERC Standard:

- Added language to Requirements 2.1, 4.1 and 5.1 to allow flexibility for the Planning Coordinator to choose the peak season on which to base the UFLS plan.
- Removed the term "distribution" from Requirements 4.1 and 5.1 to prevent the misinterpretation that only distribution load can be used for a UFLS scheme.
- Added "changes to the peak season selected in R2.1" to the list in Requirement 6 of items each UFLS entity must implement within an 18-month timeframe.
- Definition for Planning Coordinator area was added to provide clarity since the term is used in the standard's requirements. (Note: the proposed definition was removed per comments received)

These revisions were incorporated into the standard after comments received from SERC applicable entities were evaluated by the SERC Dynamics Review Subcommittee.

Comments were received from the following:

From the initial comment posting

1. Mark Riley Associated Electric Cooperative, Inc.
2. Sean Bodkin, Dominion Virginia Power
3. Darrell Vinson, Entergy Services, Inc.
4. Rich Bauer, NERC
5. Rene Free, Santee Cooper
6. Philip Kleckley, SCE & G
7. Dennis Chastain, Tennessee Valley Authority

From the Initial Ballot posting

1. David Jendras, Ameren

Commenter	Comment	Response
***Question 1**:* Do you agree with the Planning Coordinator specifying the peak season to base the UFLS plan upon?		
Yes: 7 No: 0 No Response: 0		
None	None	N/A
Question 2: Do you agree with the proposed implementation plan? The short implementation plan was specified because the changes to the standard do not require any immediate changes to applicable entities' current UFLS plans.		
Yes: 6 No: 1 No Response: 0		
Sean Bodkin, Dominion Virginia Power	The changes to the determination of the 'season' by the Planning Coordinator could result in some entities having to change internal processes, procedures, and reporting. An implementation period of 12-18 months would allow for any seasonal changes to be accommodated.	The change allowing the Planning Coordinator to determine either summer or winter peak adds flexibility, thus the SERC DRS does not agree with extending the standard's implementation plan and delaying the ability for applicable entities to utilize the added flexibility. Applicable entities can continue to use their existing processes if they choose not to use the flexibility of seasonal selection. R6 allows 18 months to implement changes to the UFLS scheme which involve frequency settings, relay time delays, or changes to the percentage of load in the scheme as requested by the Planning Coordinator.
Question 3: Please identify anything you believe needs to be modified before this revision of the document can be approved by the SERC Standards Committee.		
Yes: N/A No: N/A No Response: 2		
Sean Bodkin, Dominion Virginia Power	As a defined term, Planning Coordinator area should all be capitalized (i.e. Planning Coordinator Area) to denote a single defined term. If accepted, this should also be capitalized throughout the rest of the document. In the new definition Planning Coordinator area, transmission	The SERC standard refers Planning Coordinator area in a similar fashion as in the in the NERC standard PRC-006. The proposed Definition will be removed from the SERC standard. See also NERC *Reliability Functional Model Technical Document* for further information related to Planning Coordinator area.

Commenter	Comment	Response
	system should align with the NERC Glossary and the defined term Transmission should be used. In 2.1 'transmission' should also be capitalized.	
	In R2.1, consider using the term determined instead of chosen.	Revised 'chosen' to 'determined'.
	The Guideline and Technical basis section should be updated to the proposed version (02) rather than retaining all of the references to the original (01) version of the proposed standard. The references to the NERC standard PRC-006-1 should be updated to the current version (2).	Revised versions for SERC and NERC Standards as specified.
	The Guideline and Technical basis section #5. Remove distribution.	The term distribution is intended to describe typical load demographics for <100MW UFLS schemes thus is acceptable in the context of this explanatory material.
	Section 4 (basis for implementation schedule) should be updated to this version's implementation plan.	The change allowing the Planning Coordinator to determine either summer or winter peak adds flexibility, thus the SERC DRS does not agree with extending the standard's implementation plan and delaying the ability for applicable entities to utilize the added flexibility. Applicable entities can continue to use their existing processes if they choose not to use the flexibility of seasonal selection. R6 allows 18 months implement changes to the UFLS scheme which involve frequency settings, relay time delays, or changes to the percentage of load in the scheme as required by the Planning Coordinator.

Commenter	Comment	Response
Darrell Vinson, Entergy Services, Inc	R6 should be clarified to explain that it is in reference to changes handed down from MISO, not the typical annual adjustments that have to be made because of load changes. This is explained in section 4 of the Guidelines and Technical Basis section, but it would be helpful if the clarification was included in R6.	R4 specifies the annual adjustments made by the UFLS entity. R6 specifies the 18 months for the UFLS entity to implement changes to the UFLS scheme at the direction of the Planning Coordinator which involve frequency settings, relay time delays, or changes to the percentage of load in the scheme. R6 is limited in scope to frequency settings, relay time delays, or changes to the percentage of load in the scheme. The SERC DRS declined to make changes to the wording of R6.
Rich Bauer, NERC	I think the addition of a "no greater than" trip time would be a good enhancement. R2.6 specifies a minimum trip time but it does not specify a maximum trip time. When shedding load to arrest a frequency decline and avoid blackout, the expedience of shedding load at those frequency levels, is critical to being able to arrest the decline.	A specific 'no greater than trip time' is unnecessary because the upper limit on trip time is constrained by the performance requirements of NERC PRC-006-2 R3.
Philip Kleckley, SCE&G	The first sentence of Section 6. Background refers to "PRC-006-SERC-1" (the "0" is missing from "01"). This is inconsistent with the standard designation of "PRC-006-SERC-01".	Correction made.

Commenter	Comment	Response
Dennis Chastain, Tennessee Valley Authority	The SERC Standards Committee should consider whether the proposed addition of a definition for "Planning Coordinator area" is appropriate in this SERC region standard. This term is not presently defined in the "Glossary of Terms Used in NERC Reliability Standards" (as of 11/28/16). A defined term for "Planning Coordinator Area" would have implications for the entire ERO; therefore we believe this definition would be better addressed using the process outlined in the NERC Standard Processes Manual, beginning with the submittal of a SAR. This is essentially the same recommendation made by the NERC Alignment of Terms (Project 2015-04) drafting team in response to industry comments to that team to define "Planning Coordinator Area" [see "Consideration of Comments" document for comment period that closed 7/27/2015, posted on the Project 2015-04 project web page]. A definition developed by the SERC DRS, that has ERO-wide implications,	The SERC standard refers Planning Coordinator area in a similar fashion as in the in the NERC standard PRC-006. The proposed Definition will be removed from the SERC standard. See also NERC *Reliability Functional Model Technical Document* for further information relating to Planning Coordinator area.

Commenter	Comment	Response
	does not demonstrate an appropriate level of industry vetting.	
Question 4: Please provide any other comments on this revision of the document.		
Yes: N/A No: N/A No Response: 7		
None	None	N/A
Comments Received from Initial Ballot		
David Jendras Ameren	We recommend that selection of Peak Season be added to the three items specified in R6.	The SERC DRS agrees and is adding “changes to the peak season selected in R2.1” to the list of items that are mentioned in R6.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Regional Reliability Standards Announcement

SERC Reliability Corporation
PRC-006-SERC-02

Comment period open through July 24, 2017

Now Available

The SERC Reliability Corporation (SERC) has requested NERC to post Regional Reliability Standard **PRC-006-SERC-02 – Automatic Underfrequency Load Shedding Requirements** for industry review and comment as permitted by the NERC Rules of Procedure.

Commenting
Use the electronic form to submit comments. If you experience any difficulties in using the electronic form, contact Mat Bunch. The form must be submitted by **8 p.m. Eastern, Monday, July 24, 2017.** An unofficial Word version of the comment form is posted on the Regional Reliability Standards Under Development page.

Regional Reliability Standards Development Process
Section 300 of NERC's Rules of Procedures of the Electric Reliability Organization governs the regional reliability standards development process.

Background
The SERC Dynamics Review Subcommittee members drafted PRC-006-SERC-02 for the standard's periodic five-year review, which passed final SERC Regional ballot on May 10, 2017 with a 100% affirmative vote. The five-year review resulted in the following modifications to the Regional Reliably Standard:

- Removal of the term 'distribution' from Requirements R4.1 and R5.1 to prevent the misinterpretation that only distribution load can be used for a UFLS scheme;
- Addition of Requirements 2.1, 4.1 and 5.1, which add flexibility for the Planning Coordinator to choose the peak season (summer or winter) on which to base the UFLS plan. PRC-006-SERC-01 specifies using the previous year actual peak demand. The revision allows the Planning Coordinator to consider seasonal reliability concerns when specifying the peak on which to base the UFLS plan;
- Additional changes to the peak season selected in R2.1 to the list of items that are mentioned in R6 that allow an 18 month implementation. Changing the peak season that the UFLS plan is based on may require additional UFLS relays to be installed, thus may require more time to implement the plan.

Although the technical aspects of this Regional Reliability Standard have been vetted through SERC's Regional Standards development process, the final approval process for a Regional Reliability Standard requires NERC publicly to notice and request comment on the criteria outlined in the comment form.

Documents and information about this project are available on the SERC's Standards Under Development page.

For more information or assistance, contact Standards Developer, Mat Bunch (via email) or at (404) 446-9785.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Unofficial Comment Form

SERC Reliability Corporation
PRC-006-SERC-02

DO NOT use this form for submitting comments. Use the electronic form to submit comments on the proposed modifications to the Regional Reliability Standard **PRC-006-SERC-02 – Automatic Underfrequency Load Shedding Requirements**. The electronic form must be submitted by **8 p.m. Eastern, Monday, July 24, 2017.**

Documents and information about this project are available on the SERC's Standards Under Development page. If you have questions, contact Standards Developer, Mat Bunch (via email) or at (404) 446-9785.

Background Information

The SERC Dynamics Review Subcommittee members drafted PRC-006-SERC-02 for the standard's periodic five-year review, which passed final SERC Regional ballot on May 10, 2017 with a 100% affirmative vote. The five-year review resulted in the following modifications to the Regional Reliably Standard:

- Removal of the term 'distribution' from Requirements R4.1 and R5.1 to prevent the misinterpretation that only distribution load can be used for a UFLS scheme;
- Addition of Requirements 2.1, 4.1 and 5.1, which add flexibility for the Planning Coordinator to choose the peak season (summer or winter) on which to base the UFLS plan. PRC-006-SERC-01 specifies using the previous year actual peak demand. The revision allows the Planning Coordinator to consider seasonal reliability concerns when specifying the peak on which to base the UFLS plan;
- Additional changes to the peak season selected in R2.1 to the list of items that are mentioned in R6 that allow an 18 month implementation. Changing the peak season that the UFLS plan is based on may require additional UFLS relays to be installed, thus may require more time to implement the plan.

NERC Criteria for Developing or Modifying a Regional Reliability Standard

Regional Reliability Standard shall be: (1) a regional reliability standard that is more stringent than the continent-wide reliability standard, including a regional standard that addresses matters that the continent-wide reliability standard does not; or (2) a regional reliability standard that is necessitated by a physical difference in the bulk power system. Regional reliability standards shall provide for as much uniformity as possible with reliability standards across the interconnected bulk power system of the North American continent. Regional reliability standards, when approved by FERC and applicable authorities in Mexico and Canada, shall be made part of the body of NERC reliability standards and shall be enforced upon all applicable bulk power system owners, operators, and users within the applicable area, regardless of membership in the region.

The approval process for a regional reliability standard requires NERC to publicly notice and request comment on the proposed standard. Comments shall be permitted only on the following criteria (technical aspects of the standard are vetted through the regional standards development process):

> **Open** — Regional reliability standards shall provide that any person or entity that is directly and materially affected by the reliability of the bulk power system within the regional entity shall be able to participate in the development and approval of reliability standards. There shall be no undue financial barriers to participation. Participation shall not be conditional upon membership in the regional entity, a regional entity or any organization, and shall not be unreasonably restricted on the basis of technical qualifications or other such requirements.
>
> **Inclusive** — Regional reliability standards shall provide that any person with a direct and material interest has a right to participate by expressing an opinion and its basis, having that position considered, and appealing through an established appeals process, if adversely affected.
>
> **Balanced** — Regional reliability standards shall have a balance of interests and shall not be dominated by any two-interest categories and no single-interest category shall be able to defeat a matter.
>
> **Due Process** — Regional reliability standards shall provide for reasonable notice and opportunity for public comment. At a minimum, the standard shall include public notice of the intent to develop a standard, a public comment period on the proposed standard, due consideration of those public comments, and a ballot of interested stakeholders.
>
> **Transparent** — All actions material to the development of regional reliability standards shall be transparent. All standards development meetings shall be open and publicly noticed on the regional entity's Web site.

Review the revised PRC-006-SERC-02 regional standard and answer the following questions.

1. Do you agree the development of PRC-006-SERC-02 met the "Open" criteria as outlined above? If "No", please explain in the comment area below.

   ☐ Yes
   ☐ No
   Comments:

2. Do you agree the development of PRC-006-SERC-02 met the "Inclusive" criteria as outlined above? If "No", please explain in the comment area below.

   ☐ Yes
   ☐ No
   Comments:

3. Do you agree the development of PRC-006-SERC-02 met the “Balanced” criteria as outlined above? If “No”, please explain in the comment area below.

   ☐ Yes
   ☐ No
   Comments:

4. Do you agree the development of PRC-006-SERC-02 met the “Due Process” criteria as outlined above? If “No”, please explain in the comment area below.

   ☐ Yes
   ☐ No
   Comments:

5. Do you agree the development of PRC-006-SERC-02 met the “Transparent” criteria as outlined above? If “No”, please explain in the comment area below.

   ☐ Yes
   ☐ No
   Comments:

Comment Report

Project Name:	Regional Reliability Standard (SERC Reliability Corporation) | PRC-006-SERC-02
Comment Period Start Date:	6/9/2017
Comment Period End Date:	7/24/2017
Associated Ballots:	

There were 0 sets of responses, including comments from approximately 0 different people from approximately 0 companies representing 0 of the Industry Segments as shown in the table on the following pages.

Questions

1.Do you agree the development of PRC-006-SERC-02 met the "Open" criteria as outlined above? If "No", please explain in the comment area below.

2. Do you agree the development of PRC-006-SERC-02 met the "Inclusive" criteria as outlined above? If "No", please explain in the comment area below.

3. Do you agree the development of PRC-006-SERC-02 met the "Balanced" criteria as outlined above? If "No", please explain in the comment area below.

4. Do you agree the development of PRC-006-SERC-02 met the "Due Process" criteria as outlined above? If "No", please explain in the comment area below.

5. Do you agree the development of PRC-006-SERC-02 met the "Transparent" criteria as outlined above? If "No", please explain in the comment area below.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region

Exhibit D

SERC Engineering Committee Dynamics Review Subcommittee Roster

EC Dynamics Review Subcommittee

The Engineering Committee (EC) Dynamics Review Subcommittee (DRS) advises the EC concerning issues related to the dynamic performance and dynamic simulation of the power system.

OFFICERS

Venkat Kolluri
Chair
Entergy

PRIMARY SERC STAFF

David Greene
Program Manager, Operations
704-414-5238
dgreene@serc1.org

DOCUMENTS

Scope Document - SERC Dynamics Review Subcommittee

EC Dynamics Review Subcommittee

The Engineering Committee (EC) Dynamics Review Subcommittee (DRS) advises the EC concerning issues related to the dynamic performance and dynamic simulation of the power system.

OFFICERS

Venkat Kolluri
Chair
Entergy

PRIMARY SERC STAFF

Joe Spencer
Corporate Liaison
704-940-8208
jspencer@serc1.org

DOCUMENTS

Scope Document - SERC Dynamics Review Subcommittee

EC Dynamics Review Subcommittee (DRS)
Committee Members Roster Report by Company

Committee Member	Representing
Robbie Bottoms Tennessee Valley Authority *Elec. Engineer Planning*	Central Subregion Representative
Tom Cain Tennessee Valley Authority *Electrical Engineer*	Central Subregion Alternate
Zakia El Omari Georgia Transmission Corporation *Bulk System Planning*	Southeastern Subregion Alternate
Rick Foster Ameren Services Company *Consulting Engineer*	Gateway Subregion Representative
Jonathan Glidewell Southern Company Services, Inc. - Trans *Engineer, SR*	Southeastern Subregion Representative
Venkat Kolluri Entergy *Manager, Transmission Planning*	Chair Delta Subregion Representative
Mei Li Entergy *Engineer II*	Delta Subregion Alternate
Jeffrey Neal South Carolina Electric & Gas Company *Engineer-Assoc*	VACAR Subregion Representative
John O'Connor Duke Energy Progress, LLC *Principal Engineer*	At-Large Representative
John Sullivan Ameren Services Company	Gateway Subregion Alternate

Engineer	
Yishan Zhao Duke Energy Carolinas, LLC *Engineer III*	VACAR Subregion Alternate
SERC Staff Support	**Representing**
Banna Underland SERC Reliability Corporation *Technical Writer*	SERC Staff Administrative Support
Evan Shuvo SERC Reliability Corporation *Reliability Engineer*	SERC Staff Support
Joe Spencer SERC Reliability Corporation *Corporate Liaison*	SERC Staff Support
David Greene SERC Reliability Corporation *Program Manager, Operations*	SERC Staff Support
Maria Haney SERC Reliability Corporation *Program Manager, Reliability Assessments & Performance Analysis*	SERC Staff Support
Mitchell Hecht SERC Reliability Corporation *Program Support Assistant*	SERC Staff Administrative Support
Gaurav Karandikar SERC Reliability Corporation *Program Manager - Engineering*	SERC Staff Support
Nathaniel Davis SERC Reliability Corporation *RA Reliability Engineer*	SERC Staff Support

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

NORTH AMERICAN ELECTRIC	**)**	**Docket Nos. RR10-1-000**
RELIABILITY CORPORATION	**)**	**RR13-3-000**

ANNUAL REPORT OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION ON WIDE-AREA ANALYSIS OF TECHNICAL FEASIBILITY EXCEPTIONS

The North American Electric Reliability Corporation ("NERC") hereby provides the 2017 Annual Report on Wide-Area Analysis of Technical Feasibility Exceptions (the "2017 Annual Report") in compliance with Paragraphs 220 and 221 of the Federal Energy Regulatory Commission's ("FERC" or "Commission") Order No. 706[1] and Appendix 4D of the NERC Rules of Procedure ("ROP"). The 2017 Annual Report covers the period from July 1, 2016 through June 30, 2017.

I. INTRODUCTION

In Order No. 706, FERC approved eight Critical Infrastructure Protection ("CIP") Reliability Standards and, among other things, directed NERC to develop a set of conditions or criteria that a Responsible Entity must follow to obtain a Technical Feasibility Exception ("TFE") from specific requirements in the CIP Reliability Standards.[2] The Commission stated that the TFE process must include: mitigation steps, a remediation plan, a timeline for eliminating the use of the TFE unless appropriate justification is provided, regular review of the continued need for the

[1] *Mandatory Reliability Standards for Critical Infrastructure Protection*, Order No.706, 122 FERC ¶ 61,040 (2008) ("Order No. 706").

[2] *Id.* at P 178.

TFE, internal approval by senior managers, and regional approval through the Electric Reliability Organization ("ERO").[3]

Order No. 706 also required that NERC submit an annual report to the Commission that provides a wide-area analysis of the use of TFEs and their effect on Bulk-Power System reliability. The Commission stated:

> The annual report must address, at a minimum, the frequency of the use of such provisions, the circumstances or justifications that prompt their use, the interim mitigation measures used to address vulnerabilities, and efforts to eliminate future reliance on the exception. . . [T]he report should contain aggregated data with sufficient detail for the Commission to understand the frequency with which specific provisions are being invoked as well as high level data regarding mitigation and remediation plans over time and by region . . . . [4]

In October 2009, NERC filed amendments to its ROP to implement the Commission's directive in Order No. 706, proposing Section 412 (Requests for Technical Feasibility Exceptions to NERC Critical Infrastructure Protection Reliability Standards) and Appendix 4D (Procedure for Requesting and Receiving Technical Feasibility Exceptions to NERC Critical Infrastructure Protection Reliability Standards). On January 21, 2010, the Commission approved NERC's amended ROP.[5]

On April 8, 2013, NERC filed revisions to Appendix 4D of the ROP to streamline the TFE approval process, reflecting NERC, Regional Entity and industry experience processing TFE

---

[3] *Id.* at P 222.

[4] *Id*. at P 220.

[5] *North American Electric Reliability Corp.*, 130 FERC ¶ 61,050 (2010), *order on compliance*, 133 FERC ¶ 61,008 (2010) ("October 1 Order"), *order on reh'g*, 133 FERC ¶ 61,209 (2010), *order on compliance*, 135 FERC ¶ 61,026 (2011) ("April 12 Order"). The Commission requested further information and clarification regarding certain aspects of the TFE process. On April 21, 2010, NERC submitted its compliance filing in response to the January 21 Order. On October 1, 2010, the Commission issued an order accepting NERC's April 2010 filing as partially compliant and directing further changes to the TFE Procedure. *See* October 1 Order. On December 23, 2010, NERC submitted a compliance filing in response to the Commission's October 1 Order, which the Commission subsequently accepted.

requests since the inception of the program. On September 3, 2013, FERC approved the proposed revisions and directed limited revisions to Appendix 4D, including modifications to: (1) specify a time frame for reporting Material Changes to TFEs upon identification and discovery; and (2) require the annual TFE report to include information on Material Change Reports and TFE expiration dates.[6] NERC submitted a compliance filing consistent with the directives from the September 2013 Order, which the Commission approved on January 30, 2014.[7] Sections 11.2.4 and 13 of Appendix 4D set forth the requirements for the annual TFE report, as modified in accordance with the September 2013 Order. The 2017 Annual Report includes the information required by the September 2013 Order.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to:

Shamai Elstein
Senior Counsel
North American Electric Reliability Corporation
1325 G St., N.W., Suite 600
Washington, D.C. 20005
202-400-3000
shamai.elstein@nerc.net

Tom Hofstetter, CISA, CISSP
Senior CIP Compliance Auditor
North American Electric Reliability Corporation
3353 Peachtree Road NE, Suite 600 – North Tower
Atlanta GA 30326
404-446-2574
tom.hofstetter@nerc.net

III. 2017 ANNUAL REPORT

In accordance with Appendix 4D of the ROP, NERC prepared the 2017 Annual Report in consultation with the Regional Entities. The Regional Entities provided regular reports to NERC regarding the types of Covered Assets for which the Regional Entities have approved TFEs.[8] In

---

[6] *North American Electric Reliability Corp.*, 144 FERC ¶ 61,180 (2013) ("September 2013 Order").

[7] *North American Electric Reliability Corp.*, Docket No. RR13-3-001 (Jan. 30, 2014) (unpublished delegated letter order).

[8] Appendix 2 of the ROP defines the term "Covered Asset" as "any BES Cyber Asset, BES Cyber System, Protected Cyber Asset, Electronic Access Control or Monitoring System, or Physical Access Control System that is subject to" a TFE.

addition, each Regional Entity provided information on the 10 elements identified in Section 13 of Appendix 4D to be included in the 2017 Annual Report. NERC compiled and analyzed the TFE data provided by the Regional Entities in preparation for the 2017 Annual Report. The following is a discussion of that data.

a. Transition to New and Modified CIP Cybersecurity Reliability Standards

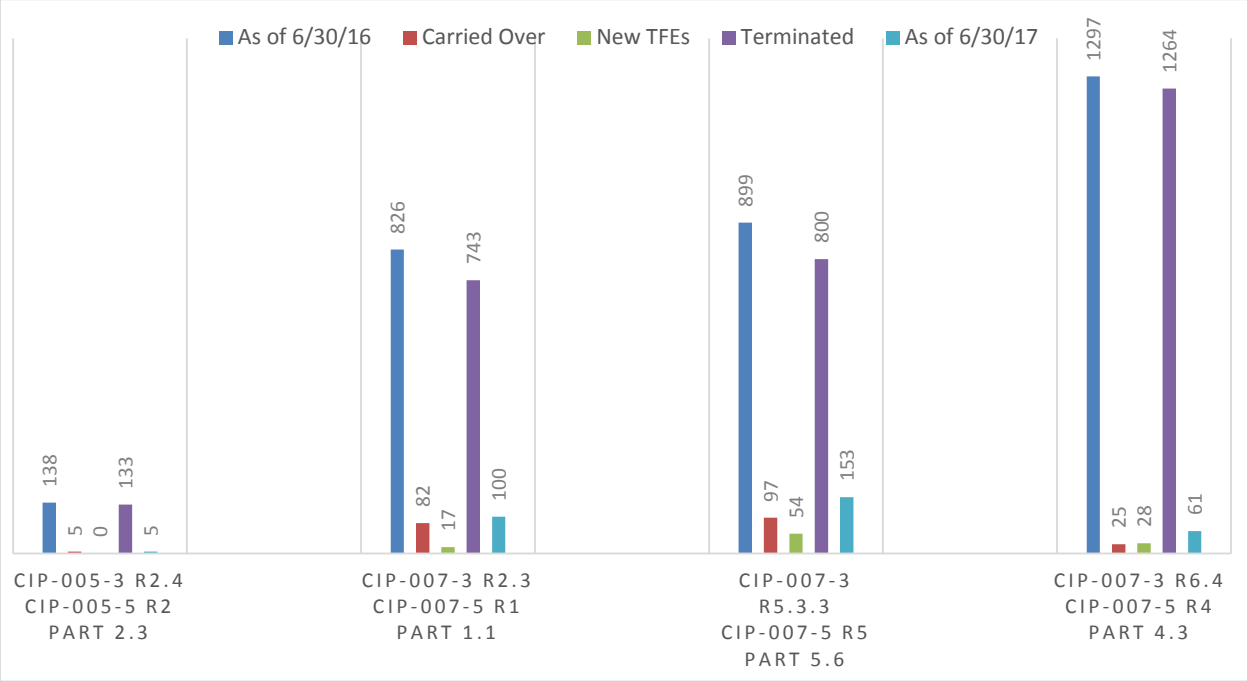
The 2017 Annual Report is the first report that includes TFE data for the suite of CIP cybersecurity Reliability Standards, CIP-002-5.1 through CIP-010-2, approved in Order No. 791, as modified in Order No. 822 which became effective on July 1, 2016.[9] As with the prior versions of the CIP cybersecurity Reliability Standards, the new and modified versions include requirements that provided for TFEs. There is not, however, a direct correlation from the prior versions in every instance (i.e., the requirements from the prior versions that were subject to TFEs may not have an equivalent requirements in the currently-effective version that is subject to a TFE, and vice versa). Where that correlation does exist, the TFE data obtained for the 2017 Annual Report indicates that there has been a significant decrease in the number of TFEs. In large part, this decrease reflects the different approach of the currently-effective CIP Reliability Standards. Under the prior version of the CIP Reliability Standards, the requirements were focused at the asset level, resulting in almost every entity with Critical Cyber Assets ("CCA") submitting a TFE request because one or more of its CCAs were technically incapable of compliance. In contrast, the currently-effective CIP Reliability Standards apply at the system level, permitting the grouping of BES Cyber Assets within BES Cyber Systems. By allowing for a system approach to

[9] *See Version 5 Critical Infrastructure Protection Reliability Standards*, Order No. 791, 145 FERC ¶ 61,160 (2013), order on clarification and reh'g, Order No. 791-A, 146 FERC ¶ 61,188 (2014); *Revised Critical Infrastructure Protection Reliability Standards*, Order No. 822, 154 FERC ¶ 61,037 (2016); *see also, Order Granting Extension of Time*, FERC ¶ 61,137 (2016).

compliance, a BES Cyber Asset that previously would have required a TFE under the prior versions because part of a BES Cyber System with overarching security controls that meet requirements of the CIP Reliability Standards, avoiding the need for a TFE.

Figure 1, below, depicts the results of this transition for the TFE requirements that were directly comparable between the currently-effective Reliability Standards and the prior version of those Reliability Standards. Similarly, the overall quantity of TFEs in the 2017 Annual Report is significantly less than prior years. Details of those comparisons are addressed in the following section.

Figure 1 – TFE Requirements Consistent from V3 – V5



b. Elements Required by Appendix 4D, Section 13.1

The following is a summary of the TFE data reported by each Regional Entity for the 10 elements identified in Section 13.1 of Appendix 4D:[10]

1. *The frequency of use of the TFE Request process, disaggregated by Regional Entity and in the aggregate for the United States and for the jurisdictions of other Applicable Governmental Authorities, including (A) the numbers of TFE Requests that have been submitted and approved/disapproved during the preceding year and cumulatively since the effective date of this Appendix, (B) the numbers of unique Covered Assets for which TFEs have been approved, (C) the numbers of approved TFEs that are still in effect as of on or about the date of the Annual Report; (D) the numbers of approved TFEs that reached their TFE Expiration Dates or were terminated during the preceding year; and (E) the numbers of approved TFEs that are scheduled to reach their TFE Expiration Dates during the ensuing year.*

    i. Frequency of Use of the TFE Request Process

The CIP Reliability Standards apply to "Responsible Entities" that are designated in Applicability Section 4.1 of each CIP cybersecurity Reliability Standard (e.g., Balancing Authority, certain Distribution Providers, etc.). From an industry-wide perspective, the number of U.S. entities with registrations to which the CIP Reliability Standards apply has increased under the currently-effective CIP Reliability Standards by nearly nine percent. Figure 2 reflects the number of entities, subject to the CIP cybersecurity Reliability Standards. In addition, Figure 2 shows the number of Responsible Entities with designated high or medium impact BES Cyber Systems and the status of TFEs.

[10] Unless stated otherwise, a table or reference to "2017" refers to the reporting period for this report: July 1, 2016 – June 30, 2017.

Figure 2 - Frequency of Use for V3 and V5 (6/30/2016 to 6/30/2017)

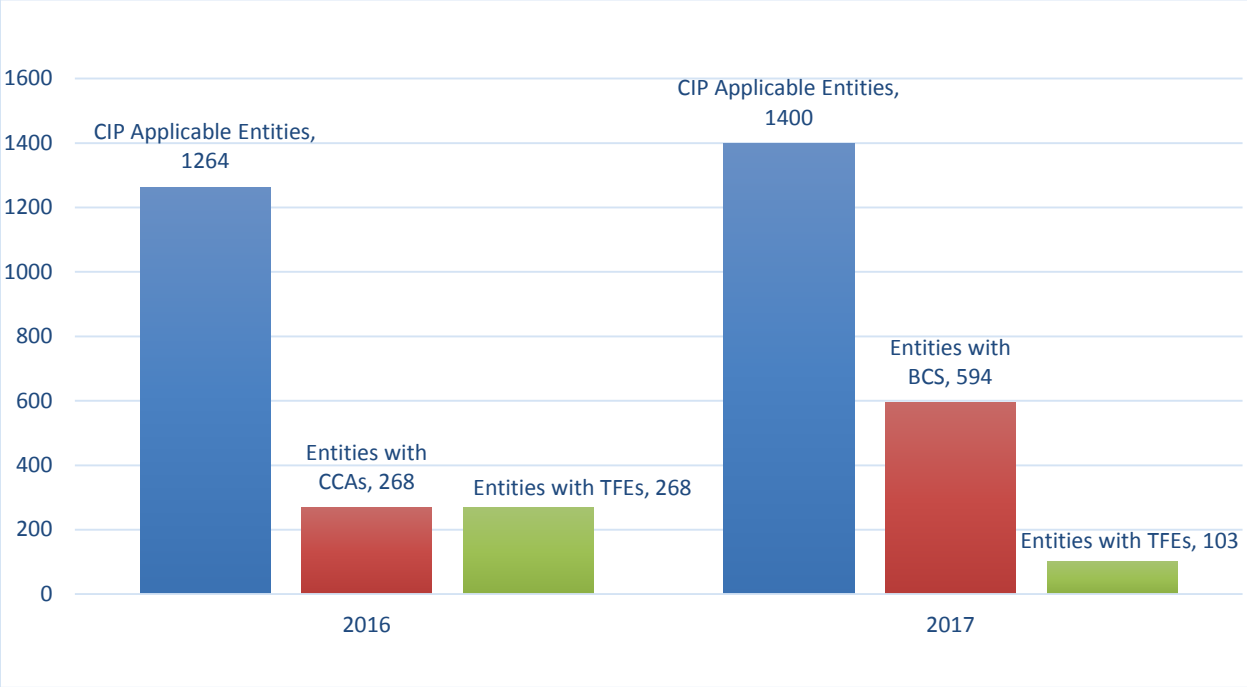
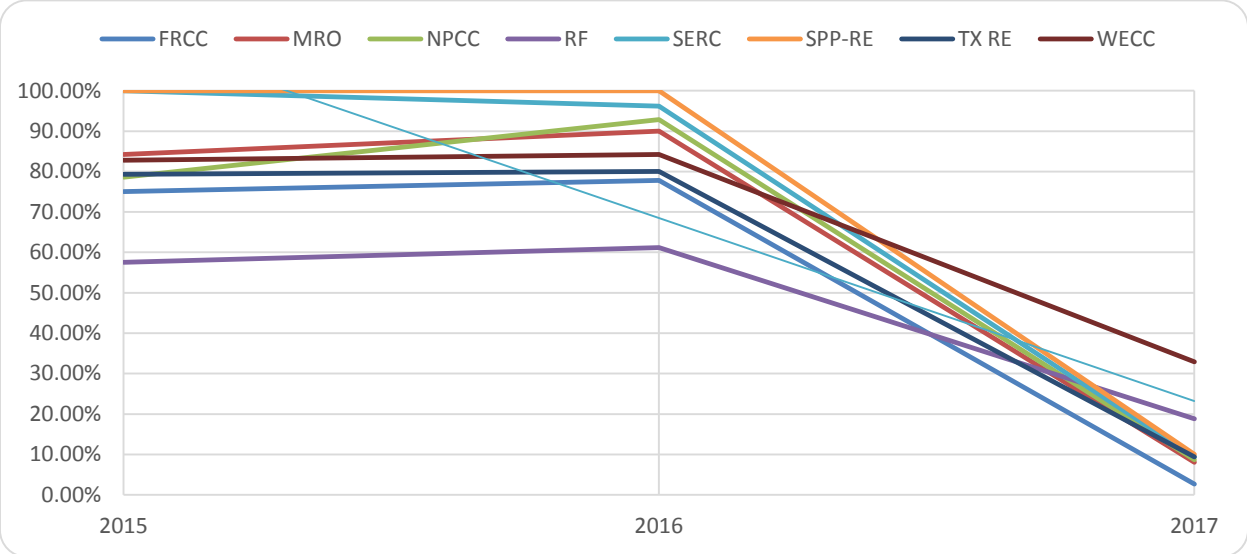


Figure 3, depicts the percentage of Responsible Entities with TFEs from 2015 through 2017. Each Regional Entity shows a large decline in the percentage of Responsible Entities with TFEs from 2016 to 2017.

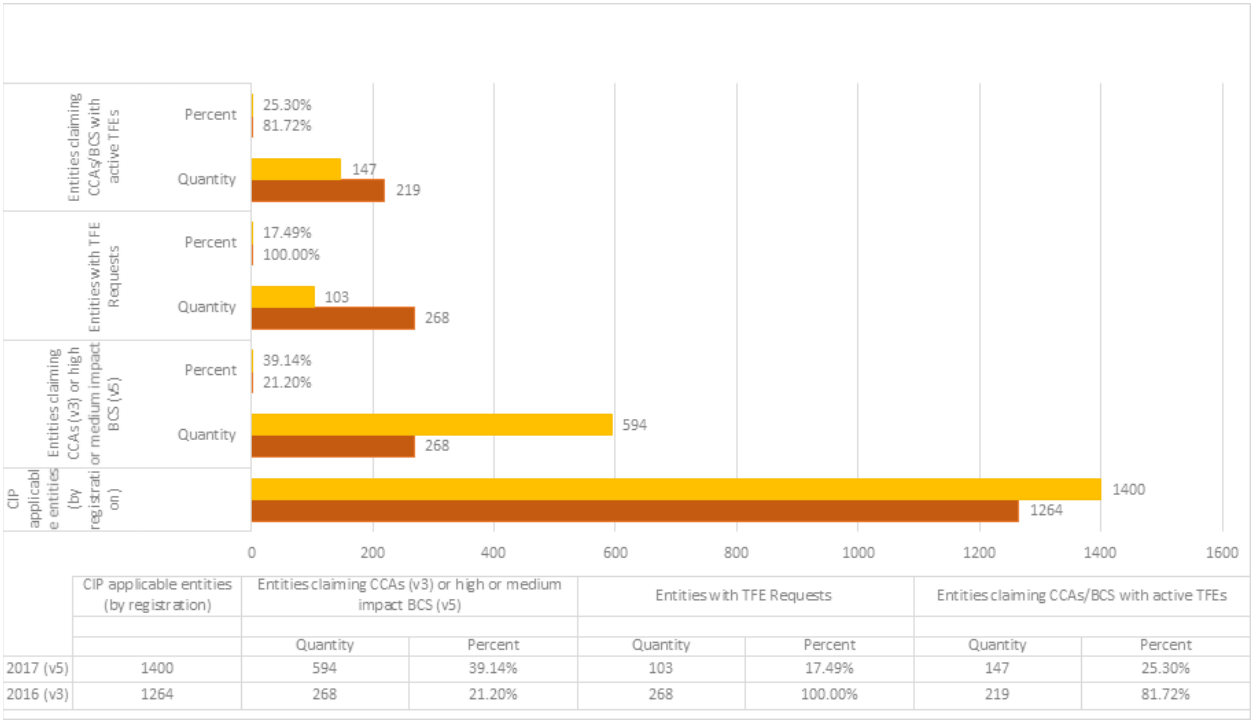
Figure 3 – Percentage of Entities with TFEs



In some cases, legacy TFEs (i.e., approved TFEs from prior version of the Reliability Standard that were automatically updated on July 1, 2016 to reflect the comparable requirement in the currently-effective Reliability Standard) are included in the number of entities with "active" TFEs. Thus, the number of Responsible Entities with active TFEs was not limited to those that submitted new TFE requests during the report period itself. There were also cases where legacy TFEs expired or terminated during the report period, as a result, there are a lower overall number of Responsible Entities with active requests at the end of the report period than the number of entities that submitted requests.

The transition to the currently-effective CIP Reliability Standards shows a marked contrast to the 2016 Annual Report; rather than a one to one ratio of Responsible Entities with TFEs, the 2017 report indicates that 25% of the Responsible Entities that reported owning high or medium impact BES Cyber Systems had TFEs. That difference is due to the fact that the currently-effective requirements are drafted at the system level and provide greater flexibility to Responsible Entities for designing protection mechanisms for a BES Cyber System, as opposed to the prior version's emphasis on individual CCAs. That system focus enables Responsible Entities to design comprehensive security solutions that are also compliant with the CIP Reliability Standards, through such measures as applying a "defense-in-depth" approach or through utilizing an application or appliance that is able to perform the specified control on behalf of an asset. Figure 4 provides a comparison between the 2016 and 2017 TFE reporting periods. The analysis shows that the percentage of Responsible Entities with TFEs has dropped from 81% from the 2016 report to 25% in the 2017 report, even though the percentage of entities to which the currently effective CIP Reliability Standards apply has increased by over 10%.

Figure 4 – Frequency of Use V3 and V5



	CIP applicable entities (by registration)	Entities claiming CCAs (v3) or high or medium impact BCS (v5)		Entities with TFE Requests		Entities claiming CCAs/BCS with active TFEs	
		Quantity	Percent	Quantity	Percent	Quantity	Percent
2017 (v5)	1400	594	39.14%	103	17.49%	147	25.30%
2016 (v3)	1264	268	21.20%	268	100.00%	219	81.72%

ii. TFE Requests that have been Submitted and Approved/Disapproved

As previously indicated, the 2017 Annual Report is unlike previous years' reports due to the impact of the revised CIP Reliability Standards. The transition to the currently-effective CIP Reliability Standards did not result in a complete replacement of all TFEs, but it did have a significant effect on the quantity of TFEs. A majority of the active TFEs are reported from three Regional Entities (WECC, RF, and NPCC). Figure 5 depicts TFE activity by Regional Entity.

Figure 6 reflects activity for TFEs that were initiated during the report period (i.e., not among the "legacy" TFEs that were updated administratively to cite a new requirement number). The data in Figure 7 reflects the same TFE activity during the report period that is depicted in Figure 6, breaking it down by requirement. The majority of the TFE activity during the report period pertained to Reliability Standard CIP-007-6 Requirement R5, Part 5.6, and Part 5.7. TFEs pertaining to Part 5.6, are more common because of assets such as RTUs, relays, network devices, PACS systems (card readers, security panels), Storage Area Network (SAN) devices,

time/frequency devices, or hardware chassis components with hard coded passwords that cannot be changed, or password changes would create issues with other systems. In the case of TFEs requested for Part 5.7, Cyber Assets are not able to limit the number of unsuccessful authentication attempts or generate alerts after a threshold of unsuccessful authentication attempts. Examples listed in TFEs include PACs devices (card readers, security panels), network devices (such as security defense appliances), time/frequency devices, and Storage Area Network ("SAN") devices.

Figure 5 – Active TFEs

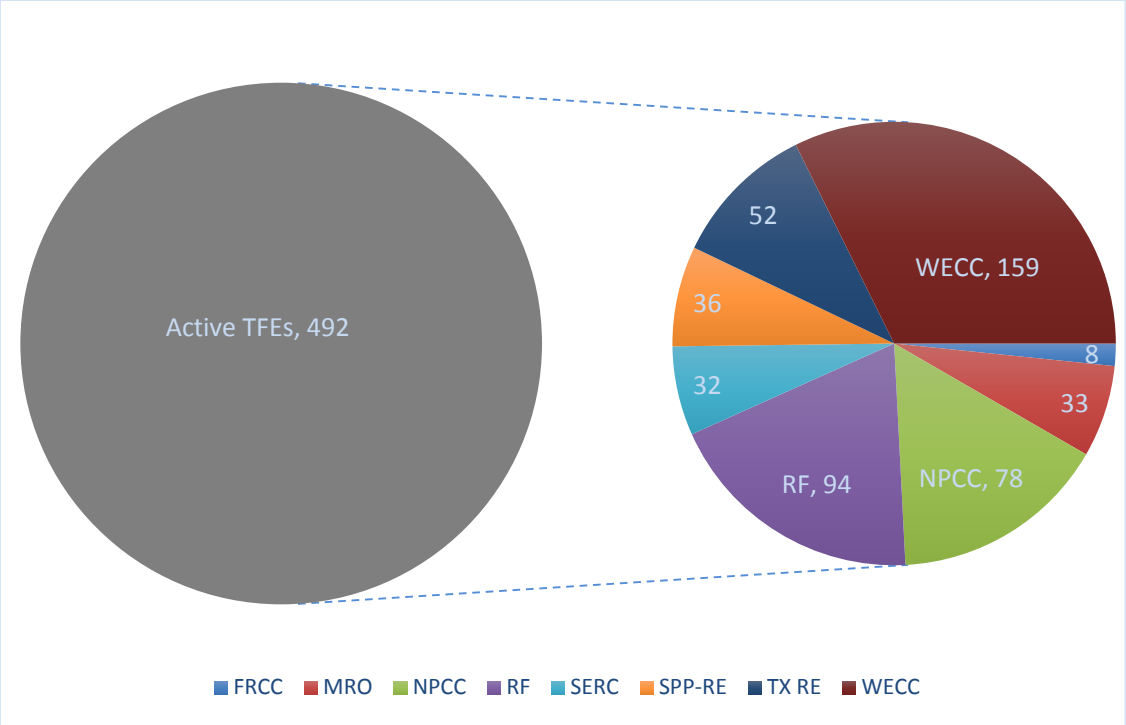


Figure 6 - TFE Requests / Changes 7/1/2016 - 6/30/2017

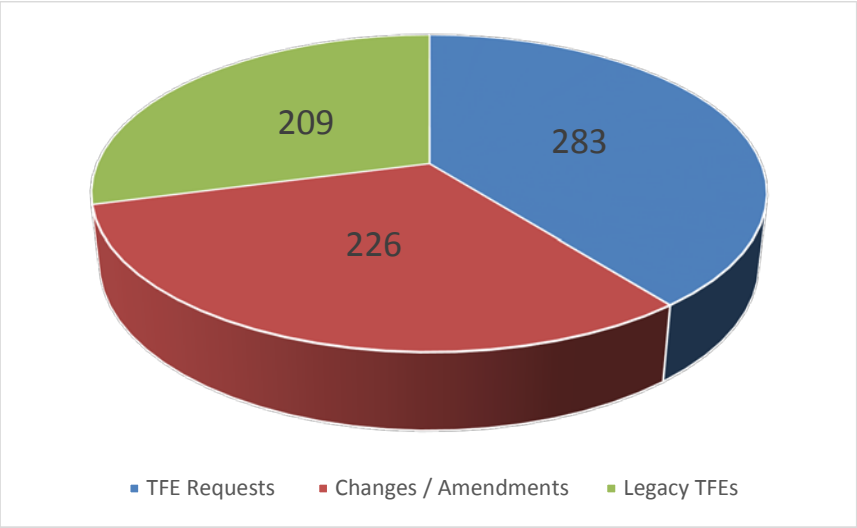
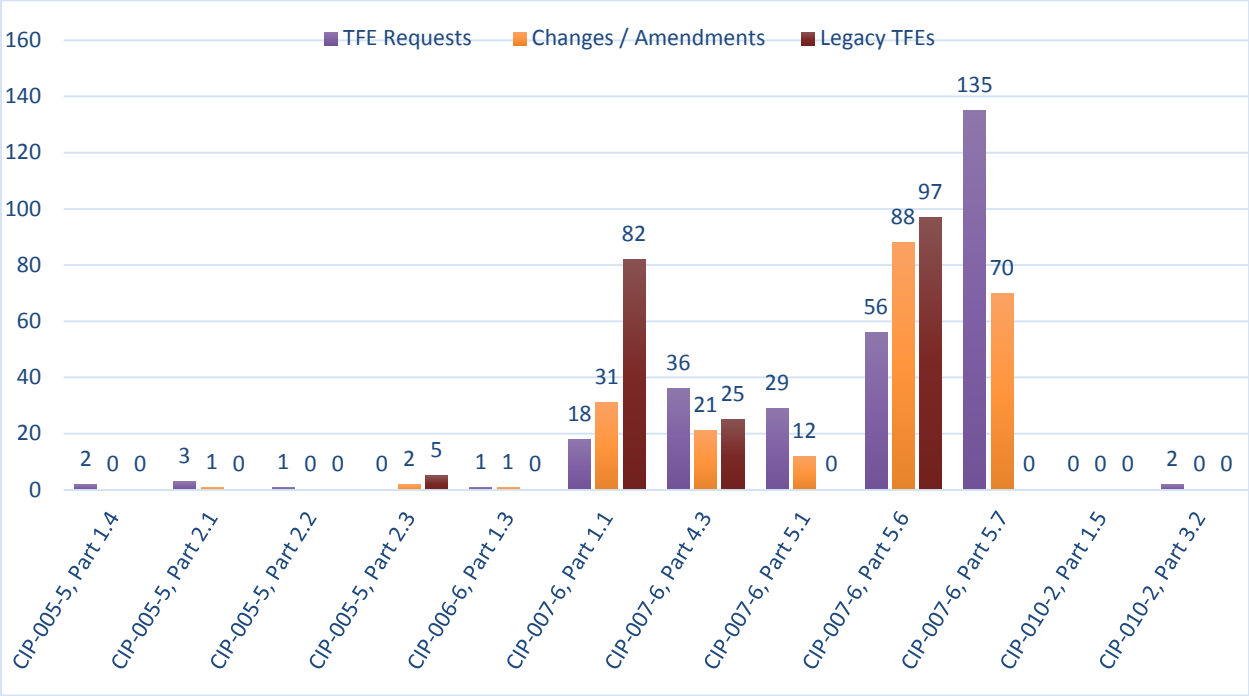


Figure 7 – TFE Requests / Changes by Requirement



Modifications to existing TFEs are tracked and reported separately from new requests but follow a similar process in their submission, review, and action. Figure 8 reflects the quantities of both new requests as well as the changes and amendments to existing requests, by requirement. In

many cases, a "single" TFE can be subjected to multiple modifications as Responsible Entities submit requests to report and track minor changes, such as updates to the quantity of assets that are the subject of the TFE.

Figure 9 pertains to modification requests that were submitted during the report period, irrespective of whether the underlying request was a new or a legacy TFE. Change requests typically due to inadvertent errors (e.g., the Responsible Entity discovers a "new" asset on the TFE change request is already part of a previously approved request) or to administratively "clear" the change request from the tracking system, such as when a Responsible Entity determines that further modifications to a pending request are necessary before the Regional Entity completes its review.

Figure 8 – ERO TFE Modifications

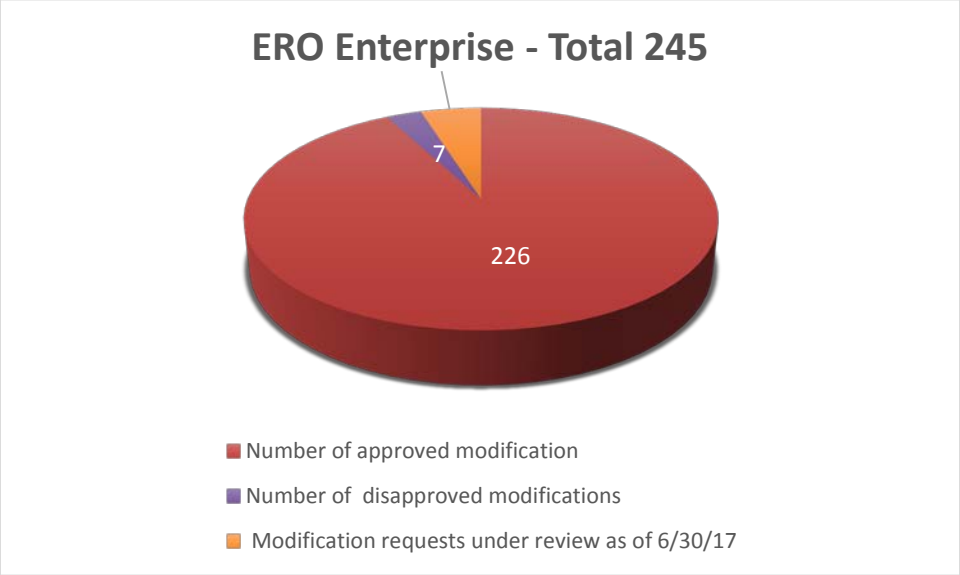
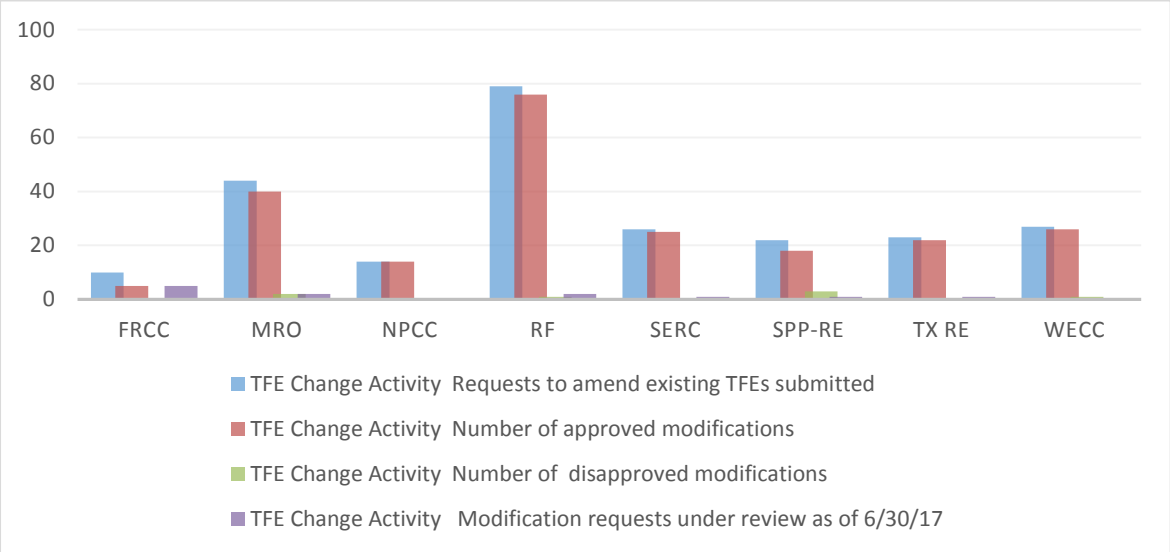


Figure 9 – ERO TFE Modifications



The total quantity of TFEs processed and in place during the 2017 Annual Report period is significantly lower than previous report periods. The results from the 2017 Annual Report period are depicted in Figure 5 and Figure 7; of particular note is the quantity of TFEs for the currently-effective version of the standards as compared to the same data from the previous year's report: a 90% decrease in the overall quantity of active TFEs. As described previously, the significant drop is considered to be a result of the currently-effective requirements providing flexibility to Responsible Entities to design protection mechanisms that address BES Cyber Systems rather than individual CCAs.

iii. Number of Unique Covered Assets for which TFEs have been Approved

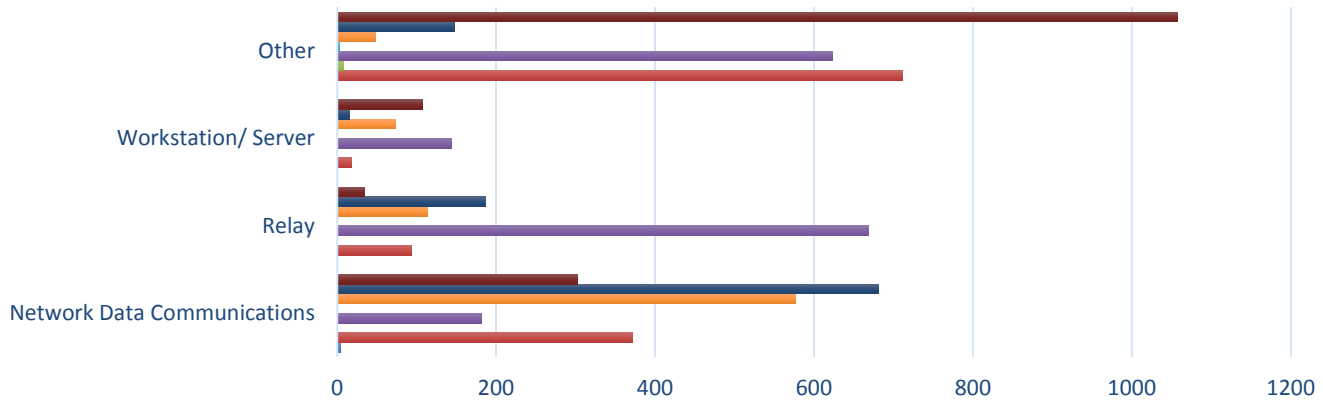
Identifying the quantity and type of unique Covered Assets for approved TFEs for prior years' reports was fairly direct, insofar as TFEs were requested on the basis of asset type, with Responsible Entities assigning each TFE request to one of four asset categories: network/data communications; relay; workstation/server; or "Other." The first three categories comprise the majority of TFE requests, and are the basis for being listed separately as category types in the TFE

request process. The “Other” category included less common assets, such as intrusion detection systems, input/output devices, etc.

The 2017 report contains similar data, with a caveat that the quantity of “other” assets in both Figure 10 and Figure 11 may include TFEs for BES Cyber Systems. A BES Cyber System could be comprised of assets that were considered “other” in past reports, but also may contain assets that would otherwise be assigned to one of the more prevalent asset categories. Figure 10 reflects the regional breakdown of assets reported for each category; Figure 11 depicts each associated CIP Reliability Standard requirements for that data.

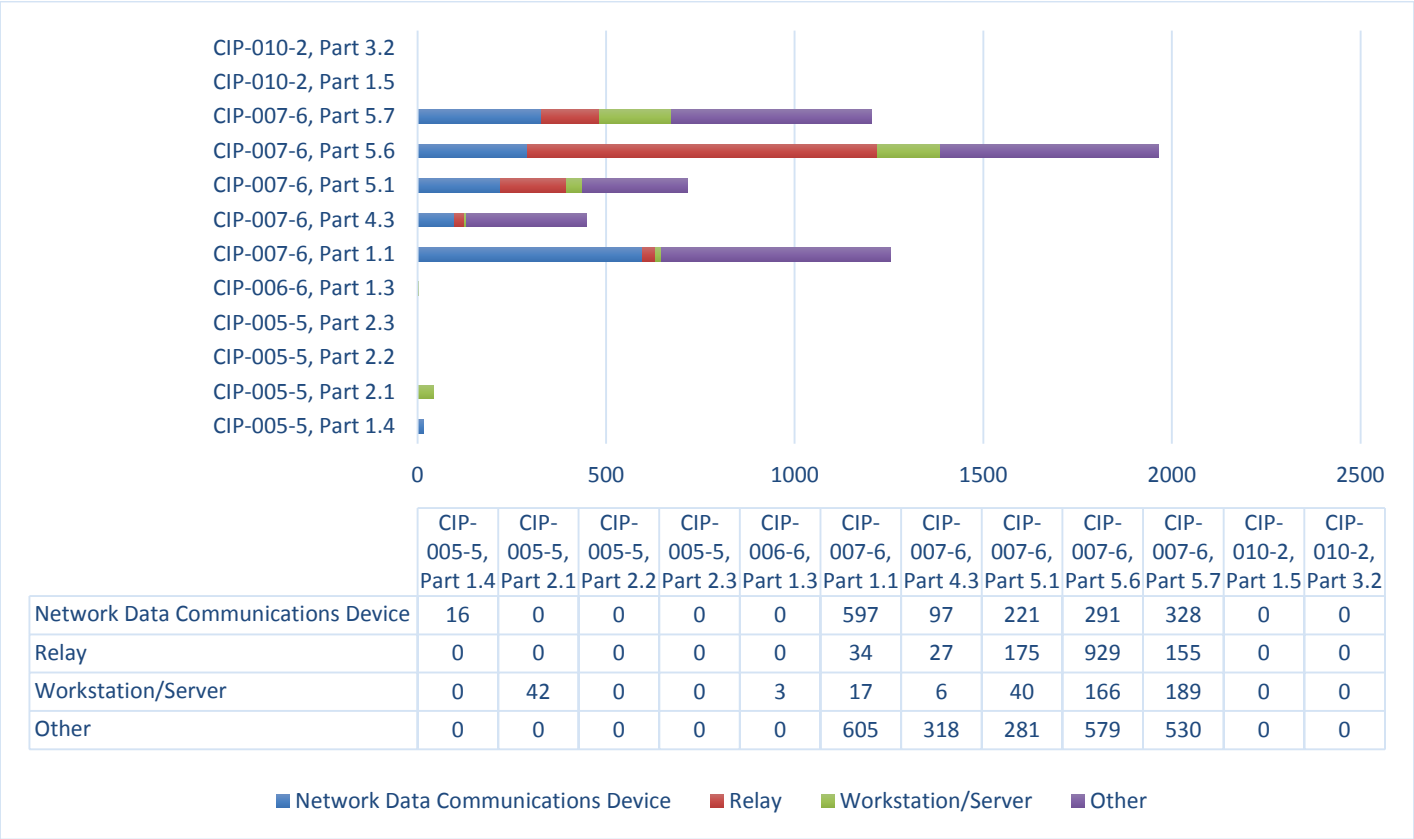
For future annual reports, the TFE Task Force (discussed elsewhere in this report) will identify methods for tracking and reporting pertinent data in support of this topic; in addition, system upgrades currently being developed within the ERO will include enhanced reporting capabilities to further identify the assets within the BES Cyber System.

Figure 10 – Number of Unique Assets with TFEs



	Network Data Communications	Relay	Workstation/ Server	Other
WECC	302	34	107	1057
TX RE	681	187	16	147
SPP-RE	577	114	73	49
SERC	0	0	0	3
RF	182	669	144	624
NPCC	0	0	0	8
MRO	372	94	18	711
FRCC	4	0	0	0

Figure 11 – TFEs by Standard / Requirement



	CIP-005-5, Part 1.4	CIP-005-5, Part 2.1	CIP-005-5, Part 2.2	CIP-005-5, Part 2.3	CIP-006-6, Part 1.3	CIP-007-6, Part 1.1	CIP-007-6, Part 4.3	CIP-007-6, Part 5.1	CIP-007-6, Part 5.6	CIP-007-6, Part 5.7	CIP-010-2, Part 1.5	CIP-010-2, Part 3.2
Network Data Communications Device	16	0	0	0	0	597	97	221	291	328	0	0
Relay	0	0	0	0	0	34	27	175	929	155	0	0
Workstation/Server	0	42	0	0	3	17	6	40	166	189	0	0
Other	0	0	0	0	0	605	318	281	579	530	0	0

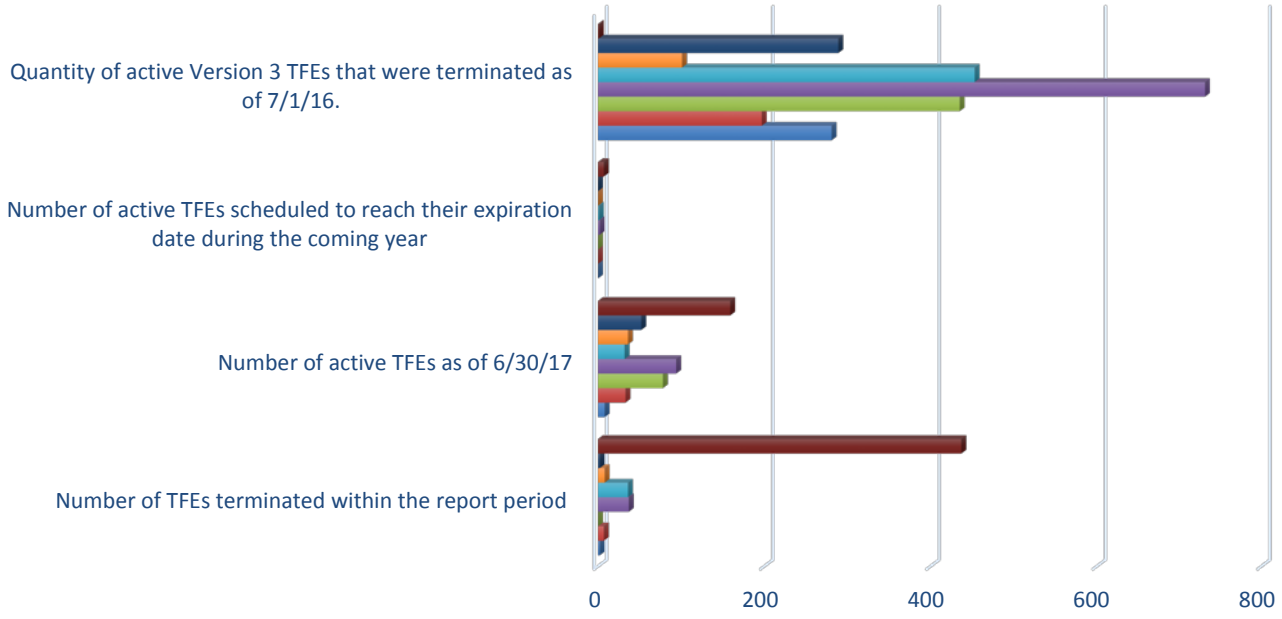
iv. Numbers of Approved TFEs Still in Effect as of the 2017 Annual Report

As depicted and discussed previously, there has been a significant decrease in the number of active TFEs as a result of the implementation of the currently-effective CIP Reliability Standards. At the end of the 2016 reporting period, there were over 3600 active TFEs; as of the end of the 2017 reporting period, that quantity decreased 80% to just under 500 active TFEs.

v. Number of TFEs that Expired or Terminated During the Reporting Period

Figure 12 shows the number of TFEs that expired or terminated during the reporting period, highlights the details of those changes, and provides the number of TFEs expected to expire or be terminated during the coming year. As noted, a significant factor in the total number of TFEs that expired or terminated is the transition to the currently-effective CIP Reliability Standards. Once the underlying requirements were superseded, the TFE was terminated.

Figure 12 - TFEs Expired or Terminated during the Reporting Period



	Number of TFEs terminated within the report period	Number of active TFEs as of 6/30/17	Number of active TFEs scheduled to reach their expiration date during the coming year	Quantity of active Version 3 TFEs that were terminated as of 7/1/16.
WECC	437	159	7	1
TX RE	2	52	0	289
SPP-RE	8	36	0	101
SERC	36	32	1	453
RF	37	94	2	731
NPCC	0	78	0	435
MRO	7	33	0	197
FRCC	2	8	0	281

vi. Number of Approved TFEs Scheduled to Reach their Expiration Dates during the Ensuing Year

See preceding section and data provided in Figure 12.

2. *Categorization of the submitted and approved TFE Requests to date by broad categories such as the general nature of the TFE Request, the Applicable Requirements covered by submitted and approved TFE Requests, and the types of Covered Assets that are the subject of submitted and approved TFE Requests.*

NERC and the Regional Entities continue to categorize submitted and approved TFEs by Applicable Requirement and type of Covered Asset. Figure 7 and Figure 9 specify the Applicable

Requirements for which the ERO has approved or disapproved TFEs. Figure 10 and Figure 11 specify the types of Covered Assets that are subject to TFE requests.

3. *Categorization of the circumstances or justifications on which the approved TFEs to date were submitted and approved, by broad categories such as the need to avoid replacing existing equipment with significant remaining useful lives, unavailability of suitable equipment to achieve Strict Compliance in a timely manner, or conflicts with other statutes and regulations applicable to the Responsible Entity.*

The transition to the currently-effective CIP Reliability Standards has not impacted the rationale used by entities for requesting TFEs. As indicated in reports from past years, a TFE request tends to be based on one of the first three criteria that are mentioned below. That pattern remains unchanged since the inception of the TFE program. To date, there have been no reports of TFEs that were approved based on any of the last three criteria:

- Not technically possible;
- Operationally infeasible;
- Precluded by technical limitations;
- Adverse effect on bulk electric system reliability;
- Cannot achieve by compliance date;
- Excessive cost that exceeds reliability benefit;
- Conflicts with other statutory or regulatory requirement; and
- Unacceptable safety risks.

4. *Categorization of the compensating measures and mitigating measures implemented and maintained by Responsible Entities pursuant to approved TFEs, by broad categories of compensating measures and mitigating measures and by types of Covered Assets.*

The ERO continues to evaluate the extent and effectiveness of compensating measures that are described in TFE requests. To address this issue, the ERO formed a "TFE Task Force," comprised of representatives from each Regional Entity as well as NERC, to review TFE requests from the entire ERO to verify sufficiency and consistency. The Task Force will perform substantive reviews of TFEs to identify positive approaches to mitigating TFEs and provide feedback in situations where it is needed. As the TFE Task Force members complete the reviews

and NERC performs oversight activities for this CMEP responsibility, information that is pertinent for the annual TFE report will be included for future reporting periods.

Although reviews are expected to be useful for identifying and sharing effective mitigating measures, auditors have observed that Responsible Entities continue to apply more than one strategy to mitigate the risk posed by a TFE. Many entities have developed defense-in-depth security controls within their CIP environments, with compensating and mitigating measures that leverage those controls. For example, a Responsible Entity may apply additional physical and logical controls that exceed the requirements, such as real-time configuration monitoring for BES Cyber Systems and having escorts call the security desk in addition to performing the required one or two-factor authentication when entering a Physical Security Perimeter.

5. *For each TFE Request that was rejected or disapproved, and for each TFE that was terminated, but for which, due to exceptional circumstances as determined by the Regional Entity, the TFE Termination Date was later than the latest date specified in Section 5.2.6, or 9.3, as applicable, a statement of the number of days the Responsible Entity was not subject to imposition of findings of violations of the Applicable Requirement or imposition of Penalties or sanctions pursuant to Section 5.3.*

All eight Regional Entities stated that there were no instances of rejection, disapproval, or termination of TFE requests during the 2017 reporting period that caused the effective date to be extended beyond the latest date specified in Section 5.2.6, or 9.3 of Appendix 4D, as applicable.

6. *A discussion, on an aggregated basis, of Compliance Audit results and findings concerning the implementation and maintenance of compensating measures and mitigating measures, and the implementation of steps and the conduct of research and analyses to achieve Strict Compliance with the Applicable Requirements, by Responsible Entities in accordance with approved TFEs.*

Appendix 4D to NERC's Rules of Procedure ("Procedure For Requesting and Receiving Technical Feasibility Exceptions to NERC Critical Infrastructure Protection Standards") is part of the Compliance Monitoring and Enforcement Program ("CMEP") that forms the framework for

Regional Entities to review and audit TFE requests. During a compliance audit, a Responsible Entity that has a TFE for a particular requirement is *not* evaluated against the applicable Reliability Standard for which a TFE was accepted and approved. Instead, the Responsible Entity is evaluated against the alternative compliance obligations assumed by the Responsible Entity (*i.e.*, compensating and mitigating measures).

All eight Regional Entities have conducted Compliance Audits where approved or terminated TFEs were in scope. Typically, an audit of a Registered Entity with TFEs will be managed according to the TFEs that need to be reviewed (i.e., based on factors such as quantity, locations, etc.). Reviews include interviewing subject matter experts specifically about TFEs, sampling evidence pertaining to a TFE's mitigating and compensating measures, etc. As was indicated in previous annual reports, Regional Entities continue to report that Responsible Entities are managing and maintaining their TFEs within the procedural requirements of Appendix 4D of the ROP. Regional Entities have also issued audit findings that identify TFEs to be processed consistent with the CMEP.

7. *Assessments, by Regional Entity (and for more discrete areas within a Regional Entity, if appropriate) and in the aggregate for the United States and for the jurisdictions of other Applicable Governmental Authorities, of the Wide-Area impacts on the reliability of the Bulk Electric System of approved TFEs in the aggregate, including the compensating measures and mitigating measures that have been implemented.*

Members of the TFE Task Force, described above, are the ERO subject matter experts in issues and concerns that are relevant to TFEs. In assessments that they have conducted and audits where they have participated, they state that the availability and utilization of TFEs in lieu of strict compliance has not had an adverse impact on BES reliability.

The Regional Entities have reported similar experiences with the execution and management of the TFE process and the manner in which it impacted the reliability of the BES. Regional Entities reported that a large majority of Responsible Entities have implemented multiple

compensating and mitigating measures for Covered Assets, and, in general, the mitigating and compensating measures of approved TFEs that were implemented in lieu of strict compliance with applicable CIP Reliability Standards accomplished the stated alternate compliance objective. As a result, the level of security for the BES achieved through the TFE process is comparable to strict compliance with the applicable Reliability Standards.

8. *Discussion of efforts to eliminate future reliance on TFEs.*

The value of a technical feasibility exception is the safe harbor it provides from violations when strict compliance is not achievable. However, the Responsible Entity merely provides a different type of compliance evidence when filing a TFE. The mitigations required by the TFE, compliance through other means, is still necessary while strict compliance is not met. Given that the significant decrease in the total filed TFEs, ERO compliance staff will provide feedback on the adequacy of the TFEs or whether alternate methods to comply may exist. Therefore, it is NERC's recommendation to continue emphasizing internal control processes that identify, evaluate, and implement measures that support effective security.

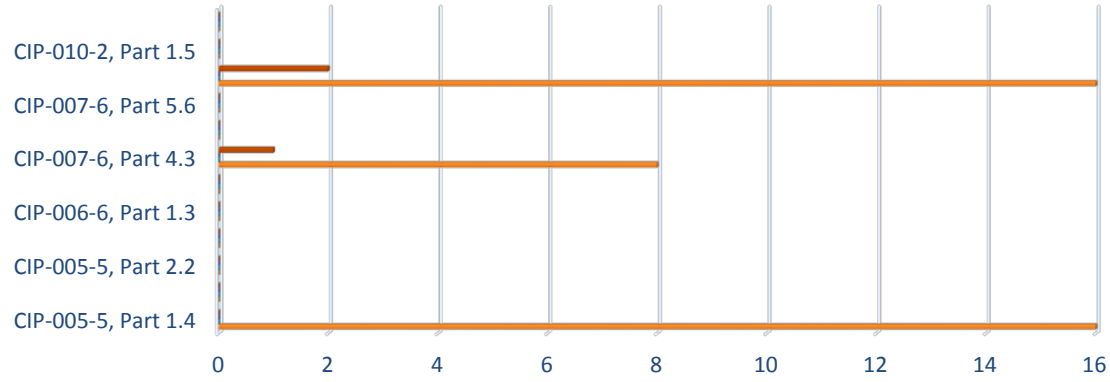
9. *Data and information regarding Material Change Reports, including the number of Material Change Reports filed annually and information regarding the types of circumstances or events that led to Material Changes, as well as any additional information NERC believes would be useful.*

When Responsible Entities update a system, replace equipment, or add assets to inventory, requests to modify existing TFEs are submitted via a "Material Change Report" ("MCR"). An MCR does not require approval by the respective Regional Entity, but the information it contains is available to the Regional Entity, which can then refer to current data when undertaking compliance activities (e.g., audits, spot checks, self-certifications, etc.). Figure 12 above includes data about active TFEs that were amended or changed during the reporting period. As indicated above, most changes are needed for asset count changes and administrative updates.

10. *Additional information about TFEs and their TFE Expiration Dates, including the number of TFEs by expiration year and CIP Standard requirement, the percentage of currently approved TFEs without TFE Expiration Dates, and the number of new TFEs approved without expiration dates annually.*

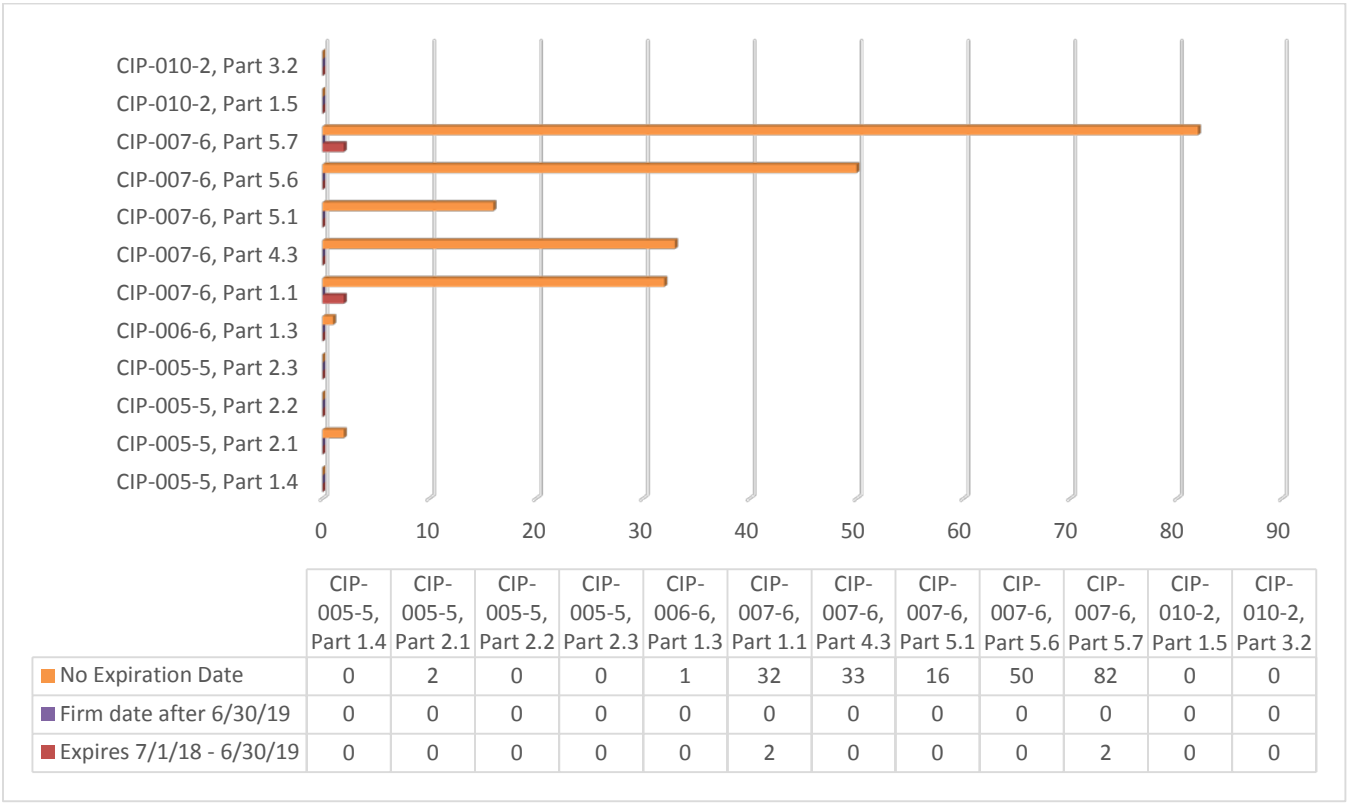
In its September 2013 Order, the Commission directed NERC to provide additional information in the annual reports related to TFEs with and without expiration dates. As has been reported previously, most TFEs do not have expiration dates. Figure 13 contains information about TFEs that are scheduled to expire before June 30, 2018; Figure 14 lists the number of TFEs that will expire later than that date.

Figure 13 – TFEs Scheduled to Expire before 6/30/2018, by Requirement



	CIP-005-5, Part 1.4	CIP-005-5, Part 2.1	CIP-005-5, Part 2.2	CIP-005-5, Part 2.3	CIP-006-6, Part 1.3	CIP-007-6, Part 1.1	CIP-007-6, Part 4.3	CIP-007-6, Part 5.1	CIP-007-6, Part 5.6	CIP-007-6, Part 5.7	CIP-010-2, Part 1.5	CIP-010-2, Part 3.2
Other	0	0	0	0	0	0	1	0	0	2	0	0
Workstation/Server	0	0	0	0	0	0	0	0	0	0	0	0
Relay	0	0	0	0	0	0	0	0	0	0	0	0
Network Data Communications Device	16	0	0	0	0	0	8	0	0	16	0	0

Figure 14 – TFE Expiring at a Later Date



	CIP-005-5, Part 1.4	CIP-005-5, Part 2.1	CIP-005-5, Part 2.2	CIP-005-5, Part 2.3	CIP-006-6, Part 1.3	CIP-007-6, Part 1.1	CIP-007-6, Part 4.3	CIP-007-6, Part 5.1	CIP-007-6, Part 5.6	CIP-007-6, Part 5.7	CIP-010-2, Part 1.5	CIP-010-2, Part 3.2
No Expiration Date	0	2	0	0	1	32	33	16	50	82	0	0
Firm date after 6/30/19	0	0	0	0	0	0	0	0	0	0	0	0
Expires 7/1/18 - 6/30/19	0	0	0	0	0	2	0	0	0	2	0	0

c. Consistency in Review, Approval and Disapproval of TFE Requests

Appendix 4D of the ROP requires that NERC and the Regional Entities collaborate to assure "consistency in the review, approval and disapproval of TFE Requests…."[11] Also, as noted above, Section 11.2.4 of the NERC Rules of Procedure requires that NERC submit with each Annual Report certain information concerning the manner in which Regional Entities have made determinations to approve or disapprove TFE requests. The scope document for the TFE Task Force that is mentioned above describes activities and deliverables that support this effort:

- Review Regional Entities' processes and performance in administering TFE Requests and Material Change Reports;
- Evaluate whether the administration of TFE activities among the Regional Entities yields consistent results;

[11] Section 11 of Appendix 4D of the NERC Rules of Procedure.

- Assess compensating and mitigating measures described in TFEs for quality and sufficiency;

- Review approved and disapproved TFE Requests or Material Change Reports for consistency; and

- Monitor active TFEs throughout their life cycle to determine whether they remain necessary and effective.

IV. CONCLUSION

For the foregoing reasons, NERC respectfully requests that the Commission accept the 2017 Annual Report.

Respectfully submitted,

/s/ Shamai Elstein

Shamai Elstein
Senior Counsel
North American Electric Reliability Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
202-400-3000
shamai.elstein@nerc.net

Counsel for the North American Electric Reliability Corporation

September 28, 2017

CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 28th day of September, 2017.

/s/ Shamai Elstein

Shamai Elstein
Counsel for the North American Electric Reliability Corporation

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

September 15, 2017

VIA ELECTRONIC FILING

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C. 20426

RE: Errata to Implementation Plan for the Revised Definition of "Remedial Action Scheme Docket No. RM15-13-___

Dear Ms. Bose:

The North American Electric Reliability Corporation ("NERC") hereby requests approval of errata to the Implementation Plan for the Revised Definition of "Remedial Action Scheme" (the "RAS Implementation Plan") approved in Order No. 818 in the above-captioned docket.[1] As explained below, the errata is necessary to incorporate into the RAS Implementation Plan certain necessary implementation provisions from the Implementation Plan associated with Reliability Standard PRC-023-3 (the "PRC-023-3 Implementation Plan") that were inadvertently omitted from the RAS Implementation Plan.

On February 3, 2015, the North American Electric Reliability Corporation ("NERC") filed a petition for approval of proposed revisions to the definition of the term "Remedial Action Scheme" ("RAS") in the *Glossary of Terms Used in NERC Reliability Standards* ("NERC Glossary") and modifications to specified Reliability Standards to incorporate the revised RAS definition in place of the term Special Protection System.[2] Among others, the PRC-023 Reliability Standard was modified to incorporate the RAS definition, moving from version PRC-023-3 to PRC-023-4. There were no other substantive changes made to the Reliability Standard at that time. The Federal Energy Regulatory Commission ("Commission") approved the revised RAS definition and modifications to the Reliability Standards in Order No. 818 on November 19, 2015.

---

[1] Order No. 818, *Revisions to Emergency Operations Reliability Standards; Revisions to Undervoltage Load Shedding Reliability Standards; Revisions to the Definition of "Remedial Action Scheme" and Related Reliability Standards*, Docket Nos. RM15-7-000 et. al., (2015).

[2] *Petition of the North American Electric Reliability Corporation for Approval of Revisions to the Definition of "Remedial Action Scheme" and Proposed Reliability Standards*, Docket No. RM15-13-000 (Feb. 3, 2015).

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

When Reliability Standard PRC-023-3 was developed, the PRC-023-3 Implementation Plan included specific provisions for load-responsive phase protection systems on circuits identified by the Planning Coordinator pursuant to Requirement R6. Specifically, the provision allows each Transmission Owner, Generator Owner, and Distribution Provider to become compliant with in Requirements R1, R2, and R3 for those systems the latter of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date.

Additionally, the PRC-023-3 Implementation Plan included provisions regarding the retirement of Requirement R1, Criterion 6, contained in PRC-023-2. Specifically, the PRC-023-3 Implementation Plan specified that Requirement R1, Criterion 6 remains in effect through the implementation of Reliability Standard PRC-025-1 as specified in the Implementation Plan associated with PRC-025-1.

Recently, NERC noticed that in developing the RAS Implementation Plan, the provisions from the PRC-023-3 discussed above were inadvertently omitted. Those provisions must be carried forward for the PRC-023-4 version of the Reliability Standard to ensure that (1) entities continue to have the appropriate implementation period for complying with requirements applicable to load-responsive phase protection systems on circuits identified by the Planning Coordinator pursuant to Requirement R6, and (2) Requirement R1, Criterion 6 from PRC-023-2 remains in effect for the appropriate time. As such, NERC revised the RAS Implementation Plan to incorporate by reference the provisions from the PRC-023-3 Implementation Plan. The proposed modifications are identified in the redline version of the revised RAS Implementation Plan, provided as **Exhibit A** hereto. The proposed clean version of the revised RAS Implementation Plan is provided in **Exhibit B**.

For the reasons set forth above, NERC respectfully requests that the Commission approve the proposed errata to the RAS Implementation Plan.

Respectfully submitted,

/s/ Shamai Elstein

Shamai Elstein
Senior Counsel
North American Electric Reliability Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 400-3000
shamai.elstein@nerc.net

Counsel for the North American Electric Reliability Corporation

CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 15th day of September, 2017.

/s/ Shamai Elstein

Shamai Elstein

Counsel for the North American Electric Reliability Corporation

Exhibit A

Implementation Plan for the Revised Definition of “Remedial Action Scheme”

Redline Version

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan for the Revised Definition of "Remedial Action Scheme"

Project 2010-05.2 – Special Protection Systems

Background

The existing Glossary of Terms Used in NERC Reliability Standards definition for "Special Protection System" ("SPS") or "Remedial Action Scheme" ("RAS") lacks the specificity necessary to consistently identify what equipment or protection schemes qualify as SPS/RAS across the eight NERC Regions. The existing definition also does not clearly stipulate the characteristics of a SPS/RAS. The actions listed in the definition of SPS, which are incorporated by cross reference (NERC Glossary of Terms) into the definition of RAS, are ambiguous and may unintentionally include equipment whose purpose is not expressly related to preserving System reliability in response to predetermined System conditions. Employing a single term, i.e., RAS, and clarifying its definition will lead to more consistent application of the NERC Reliability Standards related to RAS.

The proposed definition of RAS must be broad to include the variety of System conditions monitored and corrective actions taken by RAS. Because of the diversity of RAS in both action and objective, the practical approach to the definition is to begin with a wide scope and then list specific exclusions. Without the exclusions, equipment and schemes that should not be considered RAS could be subject to the requirements of the RAS-related NERC Reliability Standards. The exclusion list assures that commonly applied protection and control systems are not unintentionally included as RAS.

The Project 2010-05.2 SPS SDT coordinated the development of the RAS definition with the development of PRC-010-1 by the SDT for Project 2008-02 – Undervoltage Load Shedding. The UVLS SDT introduced a new term, UVLS Program, into the Glossary of Terms Used in NERC Reliability Standards to clearly establish applicability of PRC-010-1. The proposed term UVLS Program is defined as: "An automatic load shedding program consisting of distributed relays and controls used to mitigate undervoltage conditions leading to voltage instability, voltage collapse, or Cascading impacting the Bulk Electric System (BES). Centrally controlled undervoltage-based load shedding is not included."

Note that the proposed definition excludes centrally controlled undervoltage-based load shedding. The UVLS SDT maintains that the design and characteristics of centrally controlled undervoltage-based load shedding are commensurate with RAS (wherein load shedding is the remedial action) and, as such, should be subject to RAS-related Reliability Standards. The Project 2010-05.2 SPS SDT agreed with this assessment and revised the definition of RAS to clarify that it is exclusive of distributed UVLS relays including the newly defined term UVLS Program. Therefore, the definition is inclusive of centrally controlled undervoltage-based load shedding. Collectively, the two definitions will promote consistency in the identification of centrally controlled undervoltage-based load shedding as RAS. The coordination of these revisions is required to maintain coverage of those systems and prevent a reliability gap. As a

result of these revisions, all NERC Reliability Standards that include the term RAS will be applicable to centrally controlled undervoltage-based load shedding upon the effective dates of the revised definitions of RAS and UVLS Program.

Requested Approvals

The definition of "**Remedial Action Scheme**" and the standards are listed below:

The following standards are proposed for approval to align the use of the single defined term RAS. This list is intended to reflect Reliability Standards currently in effect at the time of Project development. In certain cases, a standard listed below for approval may already be retired pursuant to an implementation plan of a successor version by the time the definition of "Remedial Action Scheme" becomes effective in a particular jurisdiction. In these cases, the standard below will not become effective.

CIP-002-3(i)	PRC-004-WECC-2	PRC-020-2
CIP-002-3(i)b	PRC-005-2(ii)	PRC-021-2
EOP-004-3	PRC-005-3(ii)	PRC-023-2(i)
FAC-010-3	PRC-006-1(i)	PRC-023-4[1]
FAC-011-3	PRC-012-1	TOP-005-3a
IRO-005-3.1(i)a	PRC-013-1	TPL-001-0.1(i)
MOD-029-2a	PRC-014-1	TPL-002-0(i)b
MOD-030-3	PRC-015-1	TPL-003-0(i)b
NUC-001-2.1(i)	PRC-016-1	TPL-004-0(i)a
PRC-001-1.1(i)	PRC-017-1	

Requested Retirements

CIP-002-3	PRC-004-WECC-1	PRC-020-1
CIP-002-3b	PRC-005-2	PRC-021-1
EOP-004-2	PRC-005-3	PRC-023-2
FAC-010-2.1	PRC-006-1	PRC-023-3
FAC-011-2	PRC-012-0	TOP-005-2a
IRO-005-3.1a	PRC-013-0	TPL-001-0.1
MOD-029-1a	PRC-014-0	TPL-002-0b
MOD-030-02	PRC-015-0	TPL-003-0b
NUC-001-2.1	PRC-016-0.1	TPL-004-0a
PRC-001-1.1	PRC-017-0	

[1] There are two provisions set forth in the Implementation Plan of PRC-023-3 that are specific to load-responsive phase protection systems on circuits identified by the Planning Coordinator pursuant to Requirement R6 remain in effect. (1) Each Transmission Owner, Generator Owner, and Distribution Provider in Requirements R2 and R3 shall become compliant the later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date, and (2) Requirement R1, Criterion 6 of PRC-023-2 shall remain in force until the effective date of PRC-025-1.

General Considerations

The entity shall modify its processes as necessary to account for the revised definition. The revised definition of RAS clarifies that it is inclusive of centrally controlled undervoltage-based load shedding. Entities may have additional changes to the classification of certain schemes to align them with the revised definition.

This Implementation Plan provides additional time for entities with newly classified RAS to become compliant with the Reliability Standards during the transition to the revised definition.

All aspects of the Implementation Plans for PRC-005-2 and PRC-005-3 will remain applicable to PRC-005-2(ii) and PRC-005-3(ii). These implementation plans are incorporated here by reference.

Prerequisite Approvals

NERC Reliability Standard PRC-010-1 – Undervoltage Load Shedding
Definition of "Undervoltage Load Shedding Program (UVLS Program)" in Project 2008-02 Undervoltage Load Shedding

Revisions to the NERC Glossary of Terms

The drafting team proposes the following revised definition:

Remedial Action Scheme (RAS)
A scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation (MW and Mvar), tripping load, or reconfiguring a System(s). RAS accomplish objectives such as:

- Meet requirements identified in the NERC Reliability Standards;
- Maintain Bulk Electric System (BES) stability;
- Maintain acceptable BES voltages;
- Maintain acceptable BES power flows;
- Limit the impact of Cascading or extreme events.

The following do not individually constitute a RAS:

a. Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating the faulted Elements

b. Schemes for automatic underfrequency load shedding (UFLS) and automatic undervoltage load shedding (UVLS) comprised of only distributed relays

c. Out-of-step tripping and power swing blocking

d. Automatic reclosing schemes

e. Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, overvoltage, or overload to protect the Element against damage by removing it from service

f. Controllers that switch or regulate one or more of the following: series or shunt reactive devices, flexible alternating current transmission system (FACTS) devices, phase-shifting transformers, variable-frequency transformers, or tap-changing transformers; and, that are located at and monitor quantities solely at the same station as the Element being switched or regulated

g. FACTS controllers that remotely switch static shunt reactive devices located at other stations to regulate the output of a single FACTS device

h. Schemes or controllers that remotely switch shunt reactors and shunt capacitors for voltage regulation that would otherwise be manually switched

i. Schemes that automatically de-energize a line for a non-Fault operation when one end of the line is open

j. Schemes that provide anti-islanding protection (e.g., protect load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage)

k. Automatic sequences that proceed when manually initiated solely by a System Operator

l. Modulation of HVdc or FACTS via supplementary controls, such as angle damping or frequency damping applied to damp local or inter-area oscillations

m. Sub-synchronous resonance (SSR) protection schemes that directly detect sub-synchronous quantities (e.g., currents or torsional oscillations)

n. Generator controls such as, but not limited to, automatic generation control (AGC), generation excitation [e.g., automatic voltage regulation (AVR) and power system stabilizers (PSS)], fast valving, and speed governing

Conforming Changes to Other Standards

The existing Reliability Standards proposed for retirement contain references to SPS or RAS or both. The revised Reliability Standards will reflect the use of the single term RAS. The revised Reliability Standards noted above for approval are included in a separate document *Revised Reliability Standards for the Revised Definition of "Remedial Action Scheme."*

Effective Date for Revised Reliability Standards and Definition

Except as noted below, the revised Reliability Standards and the revised definition of "Remedial Action Scheme" shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standards and definition are 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 standards and the definition shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standards and definition are adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Implementation Plan for Newly Classified Remedial Action Schemes (RAS)

Entities with newly classified "Remedial Action Scheme" (RAS) resulting from the application of the revised definition must be fully compliant with all Reliability Standards applicable RAS twenty-four (24)

months from the Effective Date of the revised definition of RAS. This additional time applies only to existing schemes that must transition to RAS due to the revised definition. The additional time does not apply to future RAS that may be created following implementation of the revised definition.

Retirement of Existing Standards and Definitions

The requested Reliability Standards for retirement shall be retired at midnight of the day immediately prior to the Effective Date of its successor standard in the particular jurisdiction in which the revised definition is becoming effective. The current definition of "Remedial Action Scheme" shall be retired at midnight of the day immediately prior to the Effective Date of the revised definition of "Remedial Action Scheme".

Exhibit B

Implementation Plan for the Revised Definition of “Remedial Action Scheme”

Clean Version

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan for the Revised Definition of "Remedial Action Scheme"

Project 2010-05.2 – Special Protection Systems

Background

The existing Glossary of Terms Used in NERC Reliability Standards definition for "Special Protection System" ("SPS") or "Remedial Action Scheme" ("RAS") lacks the specificity necessary to consistently identify what equipment or protection schemes qualify as SPS/RAS across the eight NERC Regions. The existing definition also does not clearly stipulate the characteristics of a SPS/RAS. The actions listed in the definition of SPS, which are incorporated by cross reference (NERC Glossary of Terms) into the definition of RAS, are ambiguous and may unintentionally include equipment whose purpose is not expressly related to preserving System reliability in response to predetermined System conditions. Employing a single term, i.e., RAS, and clarifying its definition will lead to more consistent application of the NERC Reliability Standards related to RAS.

The proposed definition of RAS must be broad to include the variety of System conditions monitored and corrective actions taken by RAS. Because of the diversity of RAS in both action and objective, the practical approach to the definition is to begin with a wide scope and then list specific exclusions. Without the exclusions, equipment and schemes that should not be considered RAS could be subject to the requirements of the RAS-related NERC Reliability Standards. The exclusion list assures that commonly applied protection and control systems are not unintentionally included as RAS.

The Project 2010-05.2 SPS SDT coordinated the development of the RAS definition with the development of PRC-010-1 by the SDT for Project 2008-02 – Undervoltage Load Shedding. The UVLS SDT introduced a new term, UVLS Program, into the Glossary of Terms Used in NERC Reliability Standards to clearly establish applicability of PRC-010-1. The proposed term UVLS Program is defined as: "An automatic load shedding program consisting of distributed relays and controls used to mitigate undervoltage conditions leading to voltage instability, voltage collapse, or Cascading impacting the Bulk Electric System (BES). Centrally controlled undervoltage-based load shedding is not included."

Note that the proposed definition excludes centrally controlled undervoltage-based load shedding. The UVLS SDT maintains that the design and characteristics of centrally controlled undervoltage-based load shedding are commensurate with RAS (wherein load shedding is the remedial action) and, as such, should be subject to RAS-related Reliability Standards. The Project 2010-05.2 SPS SDT agreed with this assessment and revised the definition of RAS to clarify that it is exclusive of distributed UVLS relays including the newly defined term UVLS Program. Therefore, the definition is inclusive of centrally controlled undervoltage-based load shedding. Collectively, the two definitions will promote consistency in the identification of centrally controlled undervoltage-based load shedding as RAS. The coordination of these revisions is required to maintain coverage of those systems and prevent a reliability gap. As a

result of these revisions, all NERC Reliability Standards that include the term RAS will be applicable to centrally controlled undervoltage-based load shedding upon the effective dates of the revised definitions of RAS and UVLS Program.

Requested Approvals

The definition of "**Remedial Action Scheme**" and the standards are listed below:

The following standards are proposed for approval to align the use of the single defined term RAS. This list is intended to reflect Reliability Standards currently in effect at the time of Project development. In certain cases, a standard listed below for approval may already be retired pursuant to an implementation plan of a successor version by the time the definition of "Remedial Action Scheme" becomes effective in a particular jurisdiction. In these cases, the standard below will not become effective.

CIP-002-3(i)	PRC-004-WECC-2	PRC-020-2
CIP-002-3(i)b	PRC-005-2(ii)	PRC-021-2
EOP-004-3	PRC-005-3(ii)	PRC-023-2(i)
FAC-010-3	PRC-006-1(i)	PRC-023-4[1]
FAC-011-3	PRC-012-1	TOP-005-3a
IRO-005-3.1(i)a	PRC-013-1	TPL-001-0.1(i)
MOD-029-2a	PRC-014-1	TPL-002-0(i)b
MOD-030-3	PRC-015-1	TPL-003-0(i)b
NUC-001-2.1(i)	PRC-016-1	TPL-004-0(i)a
PRC-001-1.1(i)	PRC-017-1	

Requested Retirements

CIP-002-3	PRC-004-WECC-1	PRC-020-1
CIP-002-3b	PRC-005-2	PRC-021-1
EOP-004-2	PRC-005-3	PRC-023-2
FAC-010-2.1	PRC-006-1	PRC-023-3
FAC-011-2	PRC-012-0	TOP-005-2a
IRO-005-3.1a	PRC-013-0	TPL-001-0.1
MOD-029-1a	PRC-014-0	TPL-002-0b
MOD-030-02	PRC-015-0	TPL-003-0b
NUC-001-2.1	PRC-016-0.1	TPL-004-0a
PRC-001-1.1	PRC-017-0	

[1] This Implementation Plan carries forward and incorporates by reference the following two provisions set forth in the Implementation Plan associated with Reliability Standard PRC-023-3 that are specific to load-responsive phase protection systems on circuits identified by the Planning Coordinator pursuant to Requirement R6: (1) Each Transmission Owner, Generator Owner, and Distribution Provider in Requirements R2 and R3 shall become compliant the later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date; and (2) Requirement R1, Criterion 6 of PRC-023-2 shall remain in force until the effective date of PRC-025-1.

General Considerations

The entity shall modify its processes as necessary to account for the revised definition. The revised definition of RAS clarifies that it is inclusive of centrally controlled undervoltage-based load shedding. Entities may have additional changes to the classification of certain schemes to align them with the revised definition.

This Implementation Plan provides additional time for entities with newly classified RAS to become compliant with the Reliability Standards during the transition to the revised definition.

All aspects of the Implementation Plans for PRC-005-2 and PRC-005-3 will remain applicable to PRC-005-2(ii) and PRC-005-3(ii). These implementation plans are incorporated here by reference.

Prerequisite Approvals

NERC Reliability Standard PRC-010-1 – Undervoltage Load Shedding
Definition of "Undervoltage Load Shedding Program (UVLS Program)" in Project 2008-02 Undervoltage Load Shedding

Revisions to the NERC Glossary of Terms

The drafting team proposes the following revised definition:

Remedial Action Scheme (RAS)
A scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation (MW and Mvar), tripping load, or reconfiguring a System(s). RAS accomplish objectives such as:

- Meet requirements identified in the NERC Reliability Standards;
- Maintain Bulk Electric System (BES) stability;
- Maintain acceptable BES voltages;
- Maintain acceptable BES power flows;
- Limit the impact of Cascading or extreme events.

The following do not individually constitute a RAS:

a. Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating the faulted Elements

b. Schemes for automatic underfrequency load shedding (UFLS) and automatic undervoltage load shedding (UVLS) comprised of only distributed relays

c. Out-of-step tripping and power swing blocking

d. Automatic reclosing schemes

e. Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, overvoltage, or overload to protect the Element against damage by removing it from service

f. Controllers that switch or regulate one or more of the following: series or shunt reactive devices, flexible alternating current transmission system (FACTS) devices, phase-shifting transformers, variable-frequency transformers, or tap-changing transformers; and, that are located at and monitor quantities solely at the same station as the Element being switched or regulated

g. FACTS controllers that remotely switch static shunt reactive devices located at other stations to regulate the output of a single FACTS device

h. Schemes or controllers that remotely switch shunt reactors and shunt capacitors for voltage regulation that would otherwise be manually switched

i. Schemes that automatically de-energize a line for a non-Fault operation when one end of the line is open

j. Schemes that provide anti-islanding protection (e.g., protect load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage)

k. Automatic sequences that proceed when manually initiated solely by a System Operator

l. Modulation of HVdc or FACTS via supplementary controls, such as angle damping or frequency damping applied to damp local or inter-area oscillations

m. Sub-synchronous resonance (SSR) protection schemes that directly detect sub-synchronous quantities (e.g., currents or torsional oscillations)

n. Generator controls such as, but not limited to, automatic generation control (AGC), generation excitation [e.g., automatic voltage regulation (AVR) and power system stabilizers (PSS)], fast valving, and speed governing

Conforming Changes to Other Standards

The existing Reliability Standards proposed for retirement contain references to SPS or RAS or both. The revised Reliability Standards will reflect the use of the single term RAS. The revised Reliability Standards noted above for approval are included in a separate document *Revised Reliability Standards for the Revised Definition of "Remedial Action Scheme."*

Effective Date for Revised Reliability Standards and Definition

Except as noted below, the revised Reliability Standards and the revised definition of "Remedial Action Scheme" shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standards and definition are 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 standards and the definition shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standards and definition are adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Implementation Plan for Newly Classified Remedial Action Schemes (RAS)

Entities with newly classified "Remedial Action Scheme" (RAS) resulting from the application of the revised definition must be fully compliant with all Reliability Standards applicable RAS twenty-four (24)

months from the Effective Date of the revised definition of RAS. This additional time applies only to existing schemes that must transition to RAS due to the revised definition. The additional time does not apply to future RAS that may be created following implementation of the revised definition.

Retirement of Existing Standards and Definitions

The requested Reliability Standards for retirement shall be retired at midnight of the day immediately prior to the Effective Date of its successor standard in the particular jurisdiction in which the revised definition is becoming effective. The current definition of "Remedial Action Scheme" shall be retired at midnight of the day immediately prior to the Effective Date of the revised definition of "Remedial Action Scheme".

20170926-3000 FERC PDF (Unofficial) 09/26/2017

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

OFFICE OF ELECTRIC RELIABILITY

North American Electric Reliability Corporation
Docket No. RD17-7-000

September 26, 2017

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

Attention: Shamai Elstein
Senior Counsel for North American Electric Reliability Corporation

Reference: Petition of the North American Electric Reliability Corporation for Approval of Errata to Voltage and Reactive Control Reliability Standards

Dear Mr. Elstein:

On August 18, 2017, the North American Electric Reliability Corporation (NERC) filed a petition seeking Commission approval of errata to mandatory and enforceable Reliability Standards VAR-001-4.1 (Voltage and Reactive Control), VAR-002-4 (Generator Operation for Maintaining Network Schedules) and VAR-501-WECC-3 (Power System Stabilizer).

The NERC periodic review team reviewed Reliability Standards VAR-001-4.1, VAR-002-4 and VAR-501-WECC-3 and determined that these Reliability Standards are sufficient to protect reliability; each meets its reliability objective and no immediate substantive revisions are necessary. However, the periodic review team identified and recommended changes to correct errata in each of the three Reliability Standards. For proposed Reliability Standard VAR-001-4.2, the proposed changes included the use of the term “Operations Planning” instead of “Operational Planning” throughout; modifications to several Measures; and grammatical corrections in Requirement R4. Proposed Reliability Standard VAR-002-4.1 corrects capitalization of the defined term “Reactive Power” in Requirement R4, footnote 4. Lastly, in proposed Reliability Standard VAR-501-WECC-3.1, the term “Transmission Planner” is replaced by “Transmission Operator” in the violation severity level assignments.

20170926-3000 FERC PDF (Unofficial) 09/26/2017

NERC's filing was noticed on August 21, 2017, with interventions, comments and protests due on or before September 20, 2017. No interventions, comments or protests were received.

NERC's uncontested petition is hereby approved pursuant to the relevant authority delegated to the Director, Office of Electric Reliability under 18 C.F.R. § 375.303 (2017), 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 (2017).

Sincerely,

Michael Bardee, Director
Office of Electric Reliability

20170926-3000 FERC PDF (Unofficial) 09/26/2017

Document Content(s)

RD17-7-000.PDF.....1-2

160 FERC ¶ 61,070
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 40

[Docket No. RM16-13-000; Order No. 836]

Balancing Authority Control, Inadvertent Interchange, and Facility Interconnection Reliability Standards

(Issued September 20, 2017)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) approves Reliability Standards BAL-005-1 (Balancing Authority Control) and FAC-001-3 (Facility Interconnection Requirements), submitted by the North American Electric Reliability Corporation, as well as the retirement of Reliability Standards BAL-005-0.2b (Automatic Generation Control), FAC-001-2 (Facility Interconnection Requirements), and BAL-006-2 (Inadvertent Interchange).

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

FOR FURTHER INFORMATION CONTACT:

Syed Ahmad (Technical Information)
Office of Electric Reliability, Division of Reliability Standards
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426
Telephone: (202) 502-8718
Syed.Ahmad@ferc.gov

Julie Greenisen (Legal Information)
Office of the General Counsel
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426
Telephone: (202) 502-6362
Julie.Greenisen@ferc.gov

SUPPLEMENTARY INFORMATION:

160 FERC ¶ 61,070
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Neil Chatterjee, Chairman;
Cheryl A. LaFleur, and Robert F. Powelson.

Balancing Authority Control, Inadvertent Interchange, and Facility Interconnection Reliability Standards — Docket No. RM16-13-000

ORDER NO. 836

FINAL RULE

(Issued September 20, 2017)

1. Pursuant to section 215 of the Federal Power Act (FPA),[1] the Commission approves Reliability Standards BAL-005-1 (Balancing Authority Control) and FAC-001-3 (Facility Interconnection Requirements), submitted by the North American Electric Reliability Corporation (NERC), as well as the retirement of Reliability Standards BAL-005-0.2b (Automatic Generation Control), FAC-001-2 (Facility Interconnection Requirements), and BAL-006-2 (Inadvertent Interchange). The Commission also approves the associated implementation plans, violation risk factors, and violation severity levels for Reliability Standards BAL-005-1 and FAC-001-3. Finally, the Commission approves three revised definitions for the glossary of terms used in NERC's Reliability Standards (NERC Glossary).

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

2. The Commission determines that Reliability Standards BAL-005-1 and FAC-001-3 will enhance the reliability of the Bulk-Power System, as compared to currently-effective Reliability Standards BAL-005-0.2b and FAC-001-2, by clarifying and consolidating existing requirements related to frequency control. In addition, the Commission determines that the revised Reliability Standards support more accurate and comprehensive calculation of Reporting Area Control Error (Reporting ACE), by requiring timely reporting of an inability to calculate Reporting ACE and by requiring balancing authorities to maintain minimum levels of annual availability of 99.5 percent for each balancing authority's system for calculating Reporting ACE. Based on the information received in the comments on the Notice of Proposed Rulemaking in this proceeding,[2] as well as in response to a subsequent data request issued to NERC,[3] the Commission has determined that it will not, at this time, direct NERC to restore existing requirements in Requirement R15 of Reliability Standard BAL-005-0.2b related to maintaining and testing backup power supplies at primary control centers and other critical locations. We also approve NERC's request to retire Reliability Standard BAL-006-2, BAL-005-0.2b and FAC-001-2 upon the effective date of Reliability Standard BAL-005-1.

[2] *Balancing Authority Control, Inadvertent Interchange, and Facility Interconnection Reliability Standards*, Notice of Proposed Rulemaking, 81 FR 66,555 (Sept. 28, 2016), 156 FERC ¶ 61,210 (2016) (NOPR).

[3] *See* Response of the North American Electric Corporation to Data Request, Docket No. RM16-13-000 (April 7, 2017).

I. Background

A. Mandatory Reliability Standards and Order No. 693

3. Section 215 of the FPA requires a Commission-certified Electric Reliability Organization (ERO) to develop mandatory and enforceable Reliability Standards that are subject to Commission review and approval. Specifically, the Commission may approve, by rule or order, a proposed Reliability Standard or modification to a Reliability Standard if it determines that the Reliability Standard is just, reasonable, not unduly discriminatory or preferential and in the public interest.[4] Once approved, the Reliability Standards may be enforced by NERC, subject to Commission oversight, or by the Commission independently.[5]

4. Pursuant to section 215 of the FPA, the Commission established a process to select and certify an ERO,[6] and subsequently certified NERC as the ERO.[7] On March 16, 2007, the Commission issued Order No. 693, approving 83 of the initial 107 Reliability Standards filed by NERC, including Reliability Standards BAL-005-0 (Automatic Generation Control), FAC-001-0 (Facility Interconnection Requirements), and

---

[4] 16 U.S.C. 824o(d)(2).

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

[6] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[7] *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062, *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006), *aff'd sub nom. Alcoa, Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

BAL-006-1 (Inadvertent Interchange).[8] In addition to approving Reliability Standards BAL-005-0 and BAL-006-1, the Commission directed NERC to develop modifications to those Reliability Standards through the NERC standards development process.

5. With respect to Reliability Standard BAL-005-0, the Commission directed NERC to develop a modification that:

> (1) develops a process to calculate the minimum regulating reserve a balancing authority must have at any given time taking into account expected load and generation variation and transactions being ramped into or out of the balancing authority; (2) changes the title of the Reliability Standard to be neutral as to the source of regulating reserves and to allow the inclusion of technically qualified DSM and direct control load management; (3) clarifies Requirement R5 of this Reliability Standard to specify the required type of transmission or backup plans when receiving regulation from outside the balancing authority when using non-firm service; and (4) includes Levels of Non-Compliance and a Measure that provides for a verification process over the minimum required automatic generation control or regulating reserves a balancing authority must maintain.[9]

Subsequently, the Commission approved one interpretation of Reliability Standard BAL-005-0 and two errata filings.[10] The currently-effective version of the Reliability Standard is BAL-005-0.2b.

---

[8] *Mandatory Reliability Standards for the Bulk-Power System,* Order No. 693, FERC Stats. & Regs. ¶ 31,242 at PP 420, 439, and 680, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

[9] *Id.* P 420.

[10] *See Modification of Interchange and Transmission Loading Relief Reliability Standards; and Electric Reliability Organization Interpretation of Specific Requirements of Four Reliability Standards*, Order No. 713, 124 FERC ¶ 61,071 (2008); *North American Electric Reliability Corp.*, Docket No. RD09-2-000 (May 13, 2009) (delegated

6. With respect to Reliability Standard BAL-006-1, the Commission directed NERC to develop a modification "that adds Measures concerning the accumulation of large inadvertent imbalances and Levels of Non-Compliance."[11] The Commission explained the need for such a modification as follows:

> While we agree that inadvertent imbalances do not normally affect the real-time operations of the Bulk-Power System and pose no immediate threat to reliability, we are concerned that large imbalances represent dependence by some balancing authorities on their neighbors and are an indication of less than desirable balancing of generation with load. The Commission also notes that the stated purpose of this Reliability Standard is to define a process for monitoring balancing authorities to ensure that, over the long term, balancing authorities do not excessively depend on other balancing authorities in the Interconnection for meeting their demand or interchange obligations.[12]

Since then, the Commission has approved one revision to Reliability Standard BAL-006-1 to remove the regional waiver of certain requirements for the Midcontinent ISO, following the Midcontinent ISO's transition to a single balancing authority model.[13] The currently-effective version of the Reliability Standard is BAL-006-2.

---

letter order); *North American Electric Reliability Corp.*, Docket No. RD12-4-000 (Sept. 13, 2012) (delegated letter order).

[11] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 428.

[12] *Id.*

[13] *See North American Electric Reliability Corp.*, 134 FERC ¶ 61,007 (2011).

B. NERC Petition

7. On April 20, 2016, NERC filed a petition seeking approval of Reliability Standards BAL-005-1 (Balancing Authority Control) and FAC-001-3 (Facility Interconnection Requirements), nine new or revised definitions associated with the Reliability Standards, and retirement of currently-effective Reliability Standards BAL-005-0.2b (Automatic Generation Control), FAC-001-2 (Facility Interconnection Requirements), and BAL-006-2 (Inadvertent Interchange).

8. In its petition, NERC requested that the two modified Reliability Standards and the revised definitions of Automatic Generation Control, Pseudo-Tie, and Balancing Authority become effective on the first day of the first calendar quarter twelve months from the effective date of the applicable governmental authority's approval of NERC's petition. NERC also requested that the retirement of Reliability Standard BAL-006-2 become effective upon the latter of the effective date of proposed Reliability Standard BAL-005-1 and the NERC Operating Committee's approval of an Inadvertent Interchange Guideline document.

9. For the six remaining definitions (Reporting ACE[14] and its component definitions: Actual Frequency, Actual Net Interchange, Scheduled Net Interchange, Interchange

[14] NERC states that Reporting ACE "represents a Balancing Authority Area's (BAA's) Area Control Error (ACE) measured in megawatts (MW) as the difference between the BAA's Actual and Scheduled Net Interchange, plus its Frequency Bias Setting obligation and meter error corrections. Reporting ACE helps Responsible Entities provide reliable frequency control by indicating the current state of the entity's contribution to Reliability." NERC Petition at 3.

Meter Error, and Automatic Time Error Correction), NERC initially requested an effective date of July 1, 2016, to coincide with the effective date for Reliability Standard BAL-001-2. However, NERC subsequently withdrew its request for approval of the six Reporting ACE-related definitions from the instant docket, and filed for expedited approval of the six definitions in a separate docket. The six definitions were approved by delegated letter order on June 23, 2016, and are no longer at issue in the instant proceeding.[15]

10. NERC explained in its petition that Reliability Standards BAL-005-1 and FAC-001-3, and the proposed retirement of Reliability Standard BAL-006-2, came about as part of the second phase of NERC's project to "clarify, consolidate, streamline, and enhance the Reliability Standards addressing frequency control."[16] NERC indicated in its petition that the standard drafting team developed the proposed revisions after reviewing applicable Commission directives, "Paragraph 81" criteria, and the recommendations of the periodic review team that examined Reliability Standards BAL-005-0.2b and BAL-006-2.[17]

---

[15] *North American Electric Reliability Corp.*, Docket No. RD16-7-000 (June 23, 2016) (delegated letter order).

[16] NERC Petition at 2 (referencing Project 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls).

[17] *Id.* at 3 (citing *North American Electric. Reliability Corp.*, 138 FERC ¶ 61,193 at P 81, *order on reh'g and clarification*, 139 FERC ¶ 61,168 (2012); *Petition of the North American Electric Reliability Corporation for Approval of Retirement of Requirements in Reliability Standards*, Docket No. RM13-8-000, at Exhibit A

11. NERC described the revisions to Reliability Standard BAL-005-0.2b as clarifying and refining the current requirements "for accurate, consistent, and complete" reporting of Reporting ACE, which is a key frequency control and reliability indicator.[18] These revisions include relocating some of the current requirements of Reliability Standard BAL-005-0.2b, which relate to confirming that facilities are within a balancing authority's metered boundary, into Reliability Standard FAC-001-3. In addition, NERC proposed to relocate Requirement R3 of currently-effective Reliability Standard BAL-006-2 into Reliability Standard BAL-005-1, explaining that the requirement relates to ensuring that balancing authorities use consistent data sources to calculate Reporting ACE, and therefore more properly belongs in Reliability Standard BAL-005.

12. NERC explained that the revised Reliability Standards "represent substantial improvements over existing Reliability Standards by helping to support more accurate and comprehensive calculation of Reporting ACE and satisfying all remaining Commission directives for Reliability Standards BAL-005 and BAL-006."[19] Further, NERC maintained that Reliability Standard BAL-005-1 is an improvement over the currently-effective version, BAL-005-0.2b, because it "consolidates unnecessary or repetitive Requirements and moves certain metrics for calculating Reporting ACE to the

("Paragraph 81 Criteria") (filed Feb. 28, 2013); *North American Electric Reliability Corp.* Order No. 788, 145 FERC ¶ 61,147 (2013)).

[18] *Id.*

[19] *Id.* at 12.

revised, proposed definition of Reporting ACE."[20] Among other things, NERC proposed to move requirements applicable to generator operators and transmission operators in currently-effective Reliability Standard BAL-005-0.2b, into a more appropriate Reliability Standard, explaining that "[a]s the purpose of FAC-001-3 is more commensurate with interconnection responsibilities, interconnection procedures contained in currently effective BAL-005-0.2b should be included in proposed Reliability Standard FAC-001-3."[21]

13. In addition, NERC asserted that Reliability Standard BAL-005-1 improves on the currently-effective version of the Reliability Standard because proposed Requirement R2 clarifies the performance expectations for notification to reliability coordinators when a balancing authority is unable to calculate Reporting ACE for 30 minutes or more,[22] and Requirement R5 "introduces a new obligation . . . to assure the availability of a BA's system used to calculate Reporting ACE," requiring a minimum availability of 99.5 percent in each calendar year.[23]

14. NERC stated that the package of revisions reflected in its petition addresses the outstanding directives related to Reliability Standards BAL-005 and BAL-006 from Order No. 693. Specifically, NERC stated that the title of Reliability Standard

[20] *Id.* at 13.

[21] *Id.* at 23.

[22] *Id.* at 16.

[23] *Id.* at 19.

BAL-005-1 has been modified from Automatic Generation Control to Balancing Authority Control "to reflect the connection to Reporting ACE and resource-neutral requirements."[24] In addition, NERC indicated that it has revised the definition of Automatic Generation Control to ensure a resource-neutral process for controlling demand and resources.[25]

15. NERC also stated that the requirements of Reliability Standard BAL-005-1 all have a "medium" violation risk factor, thereby addressing the Commission's directive to revise the violation risk factor for Reliability Standard BAL-005-0, Requirement R17 to "medium."[26] Similarly, NERC asserted that it met the directive to consider Xcel and FirstEnergy's comments about the scope of Requirement R17, which set minimum accuracy requirements for time error and frequency devices, by retiring part of the currently-effective requirement and moving the minimum accuracy requirements into Requirement R3 of Reliability Standard BAL-005-1. NERC maintained that this response has "streamlined obligations to use specific frequency metering equipment that is necessary for operation of [automatic generation control (AGC)] and accurate

[24] *Id.* at 13 (referencing Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 404, and noting that the Commission's directive related to resource-neutrality for regulating reserves is now moot, as Requirement R2 of Reliability Standard BAL-005-0.2b, which required entities to maintain regulating reserves, has been retired).

[25] *Id.* at n.39.

[26] *Id.* at 17; *see also North American Elec. Reliability Corp.*, 121 FERC ¶ 61,179, at P 58 (2007).

calculation of Reporting ACE, as this ensures that costs associated with implementation are commensurate with reliability benefit."[27]

16. NERC proposed to move Requirement R3 from currently-effective Reliability BAL-006-2 into Reliability Standard BAL-005-1, but NERC proposed to retire the rest of the requirements of Reliability Standard BAL-006-2 (Requirements R1, R2, R4, and R5). NERC stated that the standard drafting team determined that, aside from Requirement R3, each of the requirements in Reliability Standard BAL-006-2 are "energy accounting standards" and/or are "administrative" in nature, and should accordingly be retired.[28]

17. NERC acknowledged that the Commission previously directed it to develop measures concerning the accumulation of large inadvertent imbalances, based on the Commission's concern that large imbalances may indicate an underlying problem. NERC explained, however, that the requirements of Reliability Standard BAL-001-2, which require balancing authorities to maintain clock-minute ACE within the Balancing Authority ACE Limit, as well as the requirements of Reliability Standard BAL-003-1 and proposed Reliability Standard BAL-002-2, which require entities to restore Reporting ACE within predefined bounds, prevent any excessive dependency on other entities. As NERC explained in its petition:

> Because entities are supporting frequency through this coordinated suite of reliability standards, entities will not excessively depend on other entities in the Interconnection such that the purely economic issue that was addressed by

[27] NERC Petition at 18.

[28] *Id.* at 25-26.

> BAL-006-2 becomes a reliability issue for a NERC Reliability Standard.[29]

18. In order to address "any remaining or potential concerns with retirement of BAL-006-2," NERC proposed that the retirement become effective only upon the Operating Committee's approval of an Inadvertent Interchange Guideline document.[30] NERC stated that the Inadvertent Interchange Guideline document was based on a white paper developed by the standard drafting team for Reliability Standards BAL-005 and BAL-006, and maintained that it provides an in-depth justification for why a NERC Reliability Standard is not necessary for inadvertent interchange.

19. With respect to the three proposed definitions that remain at issue in this proceeding, NERC explained that: (1) "Automatic Generation Control" has been revised to set forth a resource-neutral process for controlling demand and resources; (2) "Pseudo-Tie" has been updated to reflect the use of the term "Reporting ACE;" and (3) "Balancing Authority" has been revised to more accurately describe a balancing authority's resource demand function.

C. NERC Supplemental Filing

20. On June 14, 2016, NERC submitted supplemental information in support of its April 20, 2016 petition (Supplemental Filing), to provide additional explanation and

---

[29] *Id.* at 27.

[30] The Inadvertent Interchange Guideline document was subsequently approved by the NERC Operating Committee, on December 13, 2016. *See* NERC, *Reliability Guideline: Inadvertent Interchange* (Dec. 13, 2016, http://www.nerc.com/comm/OC/Reliability%20Guideline%20DL/Reliability_Guideline_Inadvertent_Interchange.pdf.

support for the retirement of Requirement R15 in currently-effective Reliability Standard BAL-005-0.2b.[31] In its Supplemental Filing, NERC maintained that Requirement R15 should be retired because the objectives of that requirement (i.e., to ensure the continued operation of AGC and certain data recording equipment during the loss of normal power supply) are being addressed through other Reliability Standards and requirements. Specifically, NERC maintained that Reliability Standard EOP-008-1 requires a balancing authority to have a backup control center facility and an operating plan that allows it to meet its functional obligations with regard to the reliable operation of the bulk electric system in the event that its primary control center functionality is lost.[32]

21. In addition, NERC maintained that the proposed performance requirements of Requirement R3 of Reliability BAL-005-1, which would require balancing authorities to "use frequency metering equipment for the calculation of Reporting ACE that is available a minimum of 99.95% of each calendar year," will help to ensure that balancing authorities can continuously operate the equipment necessary for the calculation of Reporting ACE, effectively eliminating the need for Requirement R15.[33]

[31] As NERC notes in its Supplemental Filing, NERC stated in its initial petition that "Requirements R2, R7 and R15 . . . are redundant, ineffective, and should be retired based on Commission-approved Paragraph 81 Criteria." NERC Supplemental Filing at 1 (quoting NERC Petition at 15).

[32] NERC Supplemental Filing at 2.

[33] *Id.* at 4.

D. Notice of Proposed Rulemaking and Data Request

22. On September 22, 2016, the Commission issued a notice of Proposed Rulemaking proposing to approve Reliability Standards BAL-005-1 and FAC-001-3, as replacements for the existing versions of those standards, and to approve the retirement of Reliability Standard BAL-006-2 on the latter of the effective date of BAL-005-1 or the NERC Operating Committee's approval of an Inadvertent Interchange Guideline. In the NOPR, the Commission raised several questions about the impact of eliminating Requirement R15 from currently-effective Reliability Standard BAL-005-0.2b, which requires responsible entities to maintain and periodically test backup power supplies at primary control centers and other critical locations.[34] The Commission indicated that, depending on the information received in comments in response to its questions, it may decide to issue a directive to restore the substance of Requirement R15 as part of a final rule.[35]

23. Five sets of comments were filed in response to the NOPR.[36] Subsequently, the Commission staff issued a data request to NERC seeking additional information about the current practices of a representative sample of entities concerning the use of backup power supplies.[37] Specifically, the Commission sought further information from a

[34] NOPR, 156 FERC ¶ 61,210 at PP 26-33.

[35] *Id.* P 25.

[36] The Appendix lists the entities that submitted comments and the shortened names used throughout this Final Rule to describe those entities.

[37] Data Request in Response to Petition Seeking Approval of Reliability Standards BAL-005-1 and FAC-001-3, Docket No. RM16-13-000 (March 7, 2017) (March 7 Data Request).

sample of existing balancing authorities, reliability coordinators, and transmission operators related to the kinds of backup power supply they maintain at control centers and other critical locations, including current testing practices for those backup power supplies. NERC submitted its response to the data request on April 7, 2017.

II. Discussion

24. Pursuant to FPA section 215(d)(2), the Commission approves Reliability Standards BAL-005-1 and FAC-001-3 as just, reasonable, not unduly discriminatory or preferential, and in the public interest. Reliability Standard BAL-005-1 and FAC-001-3 will enhance reliability as compared to currently-effective Reliability Standards BAL-005-0.2b and FAC-001-2, because the Reliability Standards clarify and consolidate existing requirements related to frequency control. In addition, Reliability Standard BAL-005-1 supports more accurate and comprehensive calculation of Reporting ACE by requiring timely reporting of an inability to calculate Reporting ACE (Requirement R2) and by requiring minimum levels of availability and accuracy for each balancing authority's system for calculating Reporting ACE (Requirement R5).

25. We also approve the violation risk factors and violation severity levels associated with Reliability Standards BAL-005-1 and FAC-001-3; the revisions to the definitions of Automatic Generation Control, Pseudo-Tie, and Balancing Authority as proposed by NERC; the retirement of Reliability Standards BAL-005-0.2b, FAC-001-2, and

BAL-006-2 in accordance with NERC's implementation plan;[38] and NERC's implementation plans for proposed Reliability Standards BAL-005-1 and FAC-001-3.

26. As discussed below, the Commission determines not to direct NERC to restore the requirement, currently found in Requirement R15 of Reliability Standard BAL-005-0.2b, to maintain and test backup power supplies at primary control centers and other critical locations at this time.

A. Reliability Standards BAL-005-1 and FAC-001-3

NOPR

27. In the NOPR, the Commission proposed to approve Reliability Standards BAL-005-1 and FAC-001-3. The Commission noted that the modified Reliability Standards would clarify and consolidate existing requirements related to frequency control, and that Reliability Standard BAL-005-1 would support more accurate and comprehensive calculation of Reporting ACE.

Comments

28. NERC, Trade Associations, and BPA submitted comments in support of the Commission's proposal to approve Reliability Standards BAL-005-1 and FAC-001-3. NERC maintains, as it did in its petition and supplemental filing, that the modified

[38] As discussed above, NERC requested that the retirement of Reliability Standard BAL-006-2 become effective upon the latter of the effective date of proposed Reliability Standard BAL-005-1 and the NERC Operating Committee's approval of the Inadvertent Interchange Guideline document. Because the NERC Operating Committee has now approved the guideline document, we approve the retirement of BAL-006-2 as of the date BAL-005-1 goes into effect.

Reliability Standards not only address all remaining directives related to BAL-005 and BAL-006, but also "substantially improve existing frequency control requirements and support stronger frequency control performance."[39] Similarly, Trade Associations argue that the Reliability Standards will support more accurate and comprehensive calculation of Reporting ACE, as the Commission recognized in the NOPR.[40]

Commission Determination

29. We approve Reliability Standards BAL-005-1 and FAC-001-3. As proposed in the NOPR, the Commission determines that the modified Reliability Standards will, overall, enhance reliability by clarifying and consolidating existing requirements related to frequency control. Specifically, the Reliability Standards will support more accurate and comprehensive calculation of Reporting ACE by requiring timely reporting of an inability to calculate Reporting ACE and by requiring balancing authorities to maintain minimum levels of annual availability of 99.5 percent for each balancing authority's system for calculating Reporting ACE.

B. Retirement of Reliability Standard BAL-005-0.2b, Requirement R15

NOPR

30. The NOPR observed that Reliability Standard BAL-005-1 does not include a requirement comparable to currently-effective Requirement R15 of Reliability Standard BAL-005-0.2b, which states as follows:

---

[39] NERC Comments at 4.

[40] Trade Associations Comments at 4.

> The Balancing Authority shall provide adequate and reliable backup power supplies and shall periodically test these supplies at the Balancing Authority's control center and other critical locations to ensure continuous operation of AGC and vital data recording equipment during loss of the normal power supply.[41]

31. The NOPR recognized that the approach taken in Reliability Standard BAL-005-1, when combined with the requirements of other Reliability Standards requiring entities to meet their functional obligations in the event of the loss of a primary control center, was intended to be a more performance-based approach to ensuring reliable operation of the bulk electric system.[42] However, the Commission expressed concern that the objectives of Requirement R15 would not be fully met by the other Reliability Standards and requirements NERC had identified, and in particular pointed out the following potential gap:

> Requirement R15 of currently-effective Reliability Standard BAL-005-0.2b helps to ensure continued operability of balancing authorities' primary control centers, despite the loss of normal power supply, without evacuation to or activation of backup control centers. Thus, this provision appears to provide additional robustness in the primary control center and mitigates the risk of problems occurring in the transition to a secondary control center.[43]

The NOPR also pointed out that balancing authorities currently appear to be the only type of functional entity explicitly required to have and to test adequate and reliable backup

[41] *See* NOPR, 156 ¶ 61,210 at P 26.

[42] *Id.* at 30.

[43] *Id.* P 31.

supply at critical locations, and that there is no provision parallel to Requirement R15 for reliability coordinators or transmission operators.[44]

32. The NOPR requested comments from NERC and others on the retirement of Requirement R15 of Reliability Standard BAL-005-0.2b, specifically asking for comment on the benefits and potential burden of retaining Requirement R15, and an explanation as to why there is no parallel to Requirement R15 for reliability coordinators and transmission operators, including whether any reason exists to distinguish between balancing authorities and other entities that may operate a control center or critical facility.[45] In addition, the Commission asked commenters to respond to six specific questions regarding the impact of retiring Requirement R15; current practices with respect to backup power supply at control centers; and the scope of other requirements identified by NERC as fulfilling the same objectives as current Requirement R15.[46]

Comments

33. NERC, Trade Associations, and BPA maintain that Requirement R15 should be retired without further directive from the Commission, as the results-based requirements of Reliability Standard BAL-005-1 represent a more comprehensive and superior approach. NERC asserts that Reliability Standard EOP-008-1's results-based or

[44] *Id.* P 30.

[45] *Id.* P 32.

[46] *Id.* P 33.

functionality-based approach is preferable overall,[47] while Trade Associations and other commenters point out that the performance levels required in Reliability Standard BAL-005-1, Requirements R3 and R5, cannot be achieved without having critical backup systems, including a backup power supply that is routinely maintained and tested.[48]

34. NERC contends that the existing requirements of R15 focus on only one factor contributing to reliable control center performance (i.e., backup power supplies), while Reliability Standard BAL-005-1 includes two performance obligations "that subsume requirement R15."[49] Specifically, NERC points out that Requirement R3 requires balancing authorities to use frequency metering equipment for calculation of Reporting ACE that is available at least 99.95 percent annually, with minimum accuracy of 0.001 Hz, and Requirement R5 requires that each system used by a balancing authority to calculate Reporting ACE also be available at least 99.5 percent annually. NERC states that these performance obligations, which provide no exceptions and include other critical elements such as data acquisition and communications, frequency metering, and ACE calculation systems, contrast with existing Requirement R15, which focuses on only one component (power supply) that contributes to performance.[50] In addition, NERC

[47] NERC Comments at 8-9.

[48] Trade Associations Comments at 8; *see also* BPA Comments at 4.

[49] NERC Comments at 5; Trade Associations Comments at 7-9.

[50] NERC Comments at 6; *see also* Trade Associations Comments at 8 (asserting that Reliability Standard BAL-005-1's required minimum performance level for calculating ACE "provides real performance measures that far exceed" the current requirements of BAL-005-0.2b, and that "entities will not be able to ensure that they can

maintains that new Requirement R3 "will ensure virtual 'continuous operation of AGC and vital data recording equipment during loss of the normal power supply,'" thereby effectively replacing Requirement R15.[51]

35. NERC also maintains, as it did in its petition, that Requirement R15 should be retired, as it is redundant with broader obligations imposed on balancing authorities, reliability coordinators, and transmission operators in Reliability Standard EOP-008-1. NERC contends that applicable entities cannot comply with Reliability Standard EOP-008-1 without addressing power sources, although NERC acknowledges that backup power supply may not always be necessary to support the required backup functionality for control center functions. NERC further points out that the functionality obligations under Requirement R1 of Reliability Standard EOP-008-1 include the obligation to address operation of vital equipment necessary for the collection of data to calculate Reporting ACE, assuming frequency metering equipment does not meet the minimum performance requirement under new Requirement R3 of BAL-005-1.[52] Overall, NERC maintains that Requirements R1 and R7 of Reliability Standard EOP-008-1 "are broader and clearer than Requirement R15, by requiring [applicable entities]

achieve this level of performance without having critical backups," including reliable backup power).

[51] *Id.* at 6 (responding to NOPR Question 5).

[52] *Id.* at 8-9 (responding to NOPR Question 6).

to have in place and test Operating Plans that address all elements (including any power sources) necessary for backup functionality."[53]

36. Trade Associations maintain, on a more general level, that overly-prescriptive requirements can be burdensome and often ineffective. Trade Associations assert that in determining whether there is adequate justification for the retirement of Requirement R15, the Commission should assess "whether [the new and remaining] requirements have sufficient rigor to ensure [bulk electric system] reliability through the continuous efforts to design, build and maintain systems to achieve the desired level of performance."[54] Trade Associations note that NERC's Independent Expert Review Panel concluded that results-based Reliability Standards would improve overall reliability.[55] Moreover, Trade Associations contend that the absence of a recommendation by the Independent Expert Review Panel to retire Requirement R15 as part of its 2013 report has no bearing on the question of retirement now, given the improvements and enhancements associated with Reliability BAL-005-1. Finally, Trade Associations raise a concern that the Commission may be misconstruing Reliability Standard BAL-005-0.2b to address a reliability concern beyond that intended for BAL-005. Trade Associations maintain that the BAL-005 Reliability Standards "were written for the express purpose of ensuring [balancing

[53] *Id.* at 10.

[54] Trade Associations Comments at 6-7.

[55] *Id.* at 7 (citing Standards Independent Expert Review Project; Chapter 5; Conclusions; at 18).

authorities] can reliably and effectively calculate Reporting ACE in order to maintain resource and demand balance within their area of responsibility."[56]

37. As to what obligations would still exist under Reliability Standard EOP-008-1 if the backup power supply obligation in Requirement R15 was retired, NERC, Trade Associations, and all other commenters addressing the question acknowledge that EOP-008-1 does not require applicable entities to have backup power supply at the primary or the secondary control center.[57] However, NERC asserts that backup functionality obligations under Requirement R1 of Reliability Standard EOP-008-1 "include the obligation to address operation of vital equipment necessary for the collection of data to calculate Reporting ACE if frequency metering equipment does not meet the minimum performance requirements under proposed R3 of BAL-005-1."[58] By contrast, the Trade Associations acknowledge that Reliability Standard EOP-008-1 does not ensure continuous operation of AGC and vital data recording equipment during the loss of normal power supply.[59]

[56] *Id.* at 7.

[57] NERC notes, for example, that Reliability Standard EOP-008-1, Requirement R1 requires entities to address power and backup power as part of their emergency plans, but acknowledges that it does not necessarily require backup power at either the primary or secondary control center. *See also* Trade Associations at 12; BPA at 3 (stating that without R15, BPA "does not believe there is an enforceable requirement to have a backup power supply to support frequency metering equipment").

[58] NERC Comments at 8-9 (responding to NOPR Question 6).

[59] Trade Associations Comments at 16.

38. With respect to the NOPR's questions on current practices regarding backup power supply, BPA and Idaho Power indicate that they have backup power supply at all of their primary and secondary control centers.[60] Trade Associations state that most companies have many layers of backup to ensure continued control center functionality, which may include backup power, backup generators and uninterrupted power supply.[61] In response to the NOPR's questions about the definition of "critical location" as currently used in Reliability Standard BAL-005-0.2b, Trade Associations state that the "other critical locations" referenced in current requirement R15 could refer to frequency metering equipment (including equipment outside the control center), ancillary computer rooms with energy management systems (EMS) and EMS backups, and other data systems needed for ACE calculation.[62]

39. With respect to the benefits and burdens of having backup power supply at certain locations, Idaho Power acknowledges the benefits of having backup power supply at primary control centers and other critical locations (including the benefit of ensuring compliance with other reliability requirements), and it states that the potential impact to reliability is no different for reliability coordinators or transmission operators.[63] Trade Associations maintain, however, that there is no need for additional requirements for

[60] BPA Comments at 3; Idaho Power Comments at 3.

[61] Trade Associations Comments at 14.

[62] *Id.* at 14.

[63] Idaho Power Comments at 2.

reliability coordinators and transmission operators related to backup power supply, because other Reliability Standards require or encourage certain levels of reliability and functionality at these locations, as evidenced by the historical lack of problems with loss of EMS or loss of power supply at control centers.[64]

40. Appelbaum primarily discusses the importance of backup power supplies in the context of communications networks. Appelbaum points to a report issued by the Federal Communications Commission in response to the June 2012 "derecho" event on communications networks and services in Virginia. The report found that communications were disrupted in large part during that event because of avoidable planning and system failures, including the lack of functional backup power, notably in central offices. Appelbaum contends, based on the derecho event, that the need to properly plan and design backup power is a critical component of reliability, and asks that the findings of the derecho event be considered when the Commission assesses the functional approach of Reliability Standard EOP-008-1.[65] Appelbaum points out that "there is no specific mention of the performance requirements of the backup power supply, the required design, or reference to an Industry Standard" in Reliability Standard EOP-008-1, which "creates a degree of ambiguity that can be exploited to avoid installing a sufficient level of redundancy in power supplies."[66] Appelbaum further states the

[64] Trade Associations Comments at 9-11.

[65] *See* Appelbaum Comments at 4.

[66] *Id.*

requirement for backup power design and testing should extend to reliability coordinators, transmission operators, and balancing authorities.[67] In sum, Appelbaum's comments stress the overall need to impose specific requirements, not merely functional obligations, related to backup power supply for critical systems.

Response to Data Request

41. In response to the Commission's March 7 Data Request requesting information on specific backup supply practices from a sampling of registered entities, NERC indicated that it collected data from nine entities, all registered as a balancing authority, reliability coordinator, transmission operator, or some combination of those functional categories. NERC indicated that the sample reflected some diversity as to size and type of entity and, therefore, the information "should be reflective of current practices throughout the industry."[68]

42. NERC's response indicates that all surveyed entities have backup power supplies at their primary and backup control centers. A number of entities responded that these backup supplies were installed prior to the effective date of NERC's mandatory Reliability Standards, and that they would not change their practices if the Commission approved the retirement of Requirement R15 of Reliability Standard BAL-005-0.2b. NERC reported that the surveyed entities have backup power supply at a number of other critical locations, which include data centers, corporate facilities, and operations centers

[67] *Id.* at 5.

[68] NERC Response to Data Request at 3.

(e.g., those housing cyber and physical security operations). NERC indicated that the surveyed entities have two types of backup power supplies at their control centers: backup generators and uninterruptible power supplies. According to NERC, each of the surveyed entities reported that it regularly tests its backup power supplies in accordance with written procedures, the majority doing monthly run testing. NERC reported that some entities also perform switchover or transfer testing on a monthly basis, while others perform such testing at longer intervals.

Commission Determination

43. We approve the retirement of Reliability Standard BAL-005-0.2b, including Requirement R15, upon the effective date of Reliability Standard BAL-005-1. Based on the NOPR comments, we determine not to direct NERC to develop modifications to the Reliability Standards to restore the substance of Requirement R15 at this time. We conclude that the performance obligations of Reliability Standards BAL-005-1 and EOP-008-1 will ensure the continued operation of AGC and certain data recording equipment during the loss of normal power supply. Moreover, based on the responses to the March 7 Data Request, we are satisfied that backup power supplies at primary and secondary control centers and other critical locations will likely continue to be used even after the retirement of Reliability Standard BAL-005-0.2b, Requirement R15. Should that practice change to the detriment of Bulk-Power System reliability after the revised Reliability Standards go into effect, the Commission may revisit this issue.

III. Information Collection Statement

44. The Paperwork Reduction Act (PRA)[69] 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. The OMB regulations require that OMB approve certain reporting and recordkeeping (collections of information) imposed by an agency.[70] Upon approval of a collection(s) of information, OMB will assign an OMB control number and expiration date. Respondents subject to the filing requirements of this rule will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number.

45. This Final Rule approves revisions to Reliability Standards BAL-005, associated with FERC-725R, and FAC-001, associated with FERC-725D. These revisions streamline and clarify the current requirements related to the calculation of Reporting ACE, a key frequency control and reliability indicator factor, including consolidating the seventeen requirements of currently-effective Reliability Standard BAL-005-0.2b, associated with FERC-725R, into seven requirements in Reliability Standard BAL-005-1; relocation of certain requirements related to interconnection requirements for transmission owners and generation owners into Reliability Standard FAC-001-3; relocation of Requirement R3 in currently-effective Reliability Standard BAL-006-2 into

[69] 44 U.S.C. 3501-3520.

[70] 5 CFR 1320.11.

Reliability Standard BAL-005-1; and relocation of certain metrics and calculations required for calculating Reporting ACE into the NERC definition of Reporting ACE and its component definitions.

46. The revisions to Reliability Standards BAL-005 and FAC-001 will not result in an increase in the record-keeping and reporting requirements imposed on balancing authorities, other than the one-time cost of administering the change to the revised Reliability Standards. All other recordkeeping and reporting obligations imposed on balancing authorities under the modified requirements essentially track those that already exist under currently-effective Reliability Standards BAL-005-0.2b and FAC-001-2. The modifications to Reliability Standard FAC-001-3 will result in a limited increase in the record-keeping and reporting requirements imposed on those transmission owners and generator owners that are not also transmission operators and generator operators (an estimated 161 entities in the United States), as shown in the chart below.[71] Many of the modifications to the Reliability Standards reflected in this Final Rule were developed to help clarify and streamline existing requirements related to calculation of Reporting ACE, and they are expected to reduce these entities' overall burden with respect to

[71] Reliability Standard FAC-001-3 replaces and strengthens currently-effective Reliability Standard FAC-001-2 by moving currently-effective Requirement R1 of Reliability Standard BAL-005-0.2b to Reliability Standard FAC-001-3, requiring that transmission owner and generator owner interconnection requirements include procedures for confirming that new or materially modified facilities connecting to the bulk electric system are within a balancing authority's metered boundaries. NERC explains that these interconnection requirements should be relocated to Reliability Standard FAC-001-3, as FAC-001-3 establishes facility interconnection requirements.

recordkeeping, reporting, and compliance. Moreover, the Final Rule approves the retirement of the majority of the requirements in Reliability Standard BAL-006-2, further reducing the overall record-keeping and reporting requirements for balancing authorities. Accordingly, the Commission estimates that the overall change in the record-keeping and reporting requirements as a result of this Final Rule will be *de minimis* on a per-entity basis.

47. Public Reporting Burden: The changes reflected in Reliability Standard BAL-005-1 are not expected to result in an increase in the annual record-keeping and reporting requirements on applicable entities (balancing authorities). However, balancing authorities will have to perform a one-time review of the modified Reliability Standard to ensure that their compliance practices (including record-keeping) are consistent with the revised requirements. The relocation of Requirement R1 of Reliability Standard BAL-005-0.2b into Reliability Standard FAC-001-3 will result in an increase in the number of entities subject to the requirement, as the requirement will be applicable to transmission owners and generator owners rather than transmission operators and generator operators. However, this limited increase in annual record-keeping and reporting burden, along with the one-time burden of administering the change from Reliability Standard BAL-005-0.2b to BAL-005-1, is expected to be offset to some extent by the decrease in record-keeping and reporting burden associated with the retirement of Reliability Standard BAL-006-2.

Data Collection FERC-725A, 725D & 725R1 (modifications in RM16-13-000)	Number of Respondents[72] (1)	Number of Responses per Respondent (2)	Total Number of Responses (1)×(2)=(3)	Average Burden Hours & Cost per Response[73] (4)	Annual Burden Hours & Total Annual Cost[74] (3)×(4)=(5)
BAL-005-1 (FERC-725R1)	BA 99	1 (one-time)	99	1 $64.29	99 $6,364.71
FAC-001-3 R3 (FERC-725D)	GO/TO 161[75]	1 (annual)	161	1 $102.04	161 $16,428.44
Retirement of current standard BAL-006-02 (FERC-725A)	BA 99	-1 (annual)	-99	-1 -$37.75	-99 -$3,737.25
TOTAL					260 $19,055.90

[72] The estimated number of respondents is based on the NERC compliance registry as of April 07, 2017. According to the NERC compliance registry, there are 64 U.S. balancing authorities (BA) in the Eastern Interconnection, 34 balancing authorities in the Western Interconnection and one balancing authority in the Electric Reliability Council of Texas (ERCOT).

[73] The burden hours and cost are based on the hourly cost for an engineer for BAL-005-1, the average of the hourly cost for an engineer and clerical staff for FAC-001-3, and the hourly cost for clerical staff for changes associated with the retirement of BAL-006-2. The estimates for cost per hour are based on 2015 wage figures and derived as follows:

- $64.29/hour, the average salary plus benefits per engineer (from Bureau of Labor Statistics at https://www.bls.gov/oes/current/naics2_22.htm);
- $37.75/hour, the average salary plus benefits per information and record clerks (from Bureau of Labor Statistics at https://www.bls.gov/oes/current/naics2_22.htm).

[74] Solely for purposes of determining the overall annual cost of the record-keeping and reporting changes reflected in this Final Rule, the one-time cost associated with

Title: FERC-725A, Mandatory Reliability Standards for the Bulk-Power System; FERC-725D, Mandatory Reliability Standards: FAC Reliability Standards; FERC-725R1, Mandatory Reliability Standards: BAL Reliability Standards

Action: Revision to existing collections.

OMB Control No: 1902-0244 (FERC-725A); 1902-0247 (FERC-725D); TBD (FERC-725R1).

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

Frequency of Responses: On-going.

Necessity of the Information: The Commission has reviewed the requirements of Reliability Standards BAL-005-1 and FAC-001-3 and has made a determination that the requirements of these Reliability Standards are necessary to implement section 215 of the FPA.

Internal Review: The Commission reviewed the revised Reliability Standards and made a determination that its action is necessary to implement section 215 of the FPA. The Commission has assured itself, by means of its internal review, that there is specific, objective support for the burden estimates associated with the information requirements.

---

administering the change to Reliability Standard BAL-005-1 is being treated as an annual cost.

[75] Per the NERC compliance registry, in the United States there are 54 generator owners (GO) that are not also generator operators and 107 transmission owners (TO) that are not also transmission operators, for a total of 161 new entities in the United States subject to Reliability Standard FAC-001-3, Requirement R3.

48. Interested persons may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street, NE Washington, DC 20426 [Attention: Ellen Brown, Office of the Executive Director, e-mail: DataClearance@ferc.gov, phone: (202) 502-8663, fax: (202) 273-0873].

49. For submitting comments concerning the collection(s) of information and the associated burden estimate(s), please send your comments to the Commission and to the Office of Management and Budget, Office of Information and Regulatory Affairs, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission, phone: (202) 395-4638, fax: (202) 395-7285]. For security reasons, comments to OMB should be submitted by e-mail to: oira_submission@omb.eop.gov. Comments submitted to OMB should include FERC-725A, FERC-725D, and FERC-725R1 and Docket Number RM16-13-000.

IV. Environmental Analysis

50. 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.[76] 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

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

not substantially change the effect of the regulations being amended.[77] The actions taken here fall within this categorical exclusion in the Commission's regulations.

V. Regulatory Flexibility Act Certification

51. The Regulatory Flexibility Act of 1980 (RFA)[78] generally requires a description and analysis of proposed rules that will have significant economic impact on a substantial number of small entities. The RFA does not mandate any particular outcome in a rulemaking. It only requires consideration of alternatives that are less burdensome to small entities and an agency explanation of why alternatives were rejected. The Small Business Administration (SBA) revised its size standard effective January 22, 2014 for electric utilities from a standard based on megawatt hours to a standard based on the number of employees, including affiliates. Under SBA's size standards, some balancing authorities, generation owners, and transmission owners will fall under the following category and associated size threshold: electric bulk power transmission and control, at 500 employees.[79]

52. As stated in the NOPR, the Commission estimates a very limited, one-time increase in record-keeping and reporting burden on balancing authorities due to the changes in the revised Reliability Standards, with no other increase in the cost of compliance. Approximately 24 of the 99 balancing authorities are expected to meet the

[77] 18 CFR 380.4(a)(2)(ii).

[78] 5 U.S.C. 601-612.

[79] 13 CFR 121.201, Sector 22 (Utilities), NAICS code 221121 (Electric Bulk Power Transmission and Control).

SBA's definition for a small entity. In addition, approximately 161 entities will be subject annually to new record-keeping and reporting requirements under revised Reliability Standard FAC-001-3, with no other increase in the cost of compliance.

53. Even assuming that the one-time cost of compliance for administering the change from Reliability Standard BAL-005-0.2b to BAL-005-1 is an annual cost, and assuming that all of the entities affected by the revisions to both BAL-005 and FAC-001 qualify as small entities, the estimated total annual cost to the industry as a whole is minimal ($19,055.90), and the average cost per affected entity is $118.36.

54. According to SBA guidance, the determination of significance of impact "should be seen as relative to the size of the business, the size of the competitor's business, and the impact the regulation has on larger competitors."[80] The Commission does not consider the estimated burden to be a significant economic impact. As a result, the Commission certifies that the revised Reliability Standards will not have a significant economic impact on a substantial number of small entities.

VI. Document Availability

55. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (http://www.ferc.gov) and in the Commission's Public Reference Room during normal

[80] U. S. Small Business Administration, *A Guide for Government Agencies How to Comply with the Regulatory Flexibility Act*, at 18 (May 2012), https://www.sba.gov/sites/default/files/advocacy/rfaguide_0512_0.pdf.

business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington, DC 20426.

56. From the Commission's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number of this document, excluding the last three digits, in the docket number field.

57. User assistance is available for eLibrary and the Commission's website during normal business hours from the Commission's Online Support at (202) 502-6652 (toll free at 1-866-208-3676) or e-mail at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202) 502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

VII. Effective Date and Congressional Notification

58. 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

List of Commenters

Abbreviation	Commenter
NERC	North American Electric Reliability Corporation
Trade Associations	Edison Electric Institute, American Public Power Association, and Large Public Power Council
BPA	Bonneville Power Administration
Idaho Power	Idaho Power Company
Appelbaum	Jonathan Appelbaum

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 40

[Docket No. RM16-20-000; Order No. 837

Remedial Action Schemes Reliability Standard

(Issued September 20, 2017)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission approves Reliability Standard PRC-012-2 (Remedial Action Schemes) submitted by the North American Electric Reliability Corporation. The purpose of Reliability Standard PRC-012-2 is to ensure that remedial action schemes do not introduce unintentional or unacceptable reliability risks to the bulk electric system.

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

FOR FURTHER INFORMATION CONTACT:

Syed Ahmad (Technical Information)
Office of Electric Reliability
Division of Reliability Standards and Security
888 First Street, NE
Washington, DC 20426
Telephone: (202) 502-8718
Syed.Ahmad@ferc.gov

Alan Rukin (Legal Information)
Office of the General Counsel
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426
Telephone: (202) 502-8502
Alan.Rukin@ferc.gov

SUPPLEMENTARY INFORMATION:

160 FERC ¶ 61,071
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Neil Chatterjee, Chairman;
Cheryl A. LaFleur, and Robert F. Powelson.

Remedial Action Schemes Reliability Standard Docket No. RM16-20-000

ORDER NO. 837

FINAL RULE

(Issued September 20, 2017)

1. Pursuant to section 215 of the Federal Power Act (FPA), the Federal Energy Regulatory Commission (Commission) approves Reliability Standard PRC-012-2 (Remedial Action Schemes).[1] The North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization (ERO), submitted Reliability Standard PRC-012-2 for approval. The purpose of Reliability Standard PRC-012-2 is to ensure that remedial action schemes do not introduce unintentional or unacceptable reliability risks to the bulk electric system. In addition, the Commission approves the associated violation risk factors and violation severity levels, implementation plan, and effective date proposed by NERC. The Commission also approves the retirement of currently-effective Reliability Standards PRC-015-1 and

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

PRC-016-1 as well as NERC's request to withdraw proposed Reliability Standards PRC-012-1, PRC-013-1, and PRC-014-1, which are now pending before the Commission.

I. Background

A. Section 215 and Mandatory Reliability Standards

2. Section 215 of the FPA requires a Commission-certified ERO to develop mandatory and enforceable Reliability Standards, subject to Commission review and approval.[2] Once approved, the Reliability Standards may be enforced by the ERO subject to Commission oversight or by the Commission independently.[3] In 2006, the Commission certified NERC as the ERO pursuant to section 215 of the FPA.[4]

B. Order No. 693

3. On March 16, 2007, the Commission issued Order No. 693, approving 83 of the 107 Reliability Standards filed by NERC, including Reliability Standards PRC-015-1 (Remedial Action Scheme Data and Documentation) and PRC-016-1 (Remedial Action

[2] *Id.* 824o(c), (d).

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

[4] *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062 (ERO Certification Order), *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006), *order on compliance*, 118 FERC ¶ 61,190, *order on reh'g*, 119 FERC ¶ 61,046 (2007), *aff'd sub nom. Alcoa Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

Scheme Misoperation).[5] Reliability Standard PRC-015-1 requires transmission owners, generator owners, and distribution providers to maintain a listing; retain evidence of review; and provide documentation of existing, new or functionally modified special protection systems.[6] Reliability Standard PRC-016-1 requires transmission owners, generator owners, and distribution providers to provide the regional reliability organization with documentation, analyses and corrective action plans for misoperation of special protection systems.[7]

4. In Order No. 693, the Commission determined that then-proposed Reliability Standard PRC-012-0 was a "fill-in-the-blank" Reliability Standard because, while it would require regional reliability organizations to ensure that all special protection systems are properly designed, meet performance requirements, and are coordinated with other protection systems, NERC had not submitted any regional review procedures with the proposed Reliability Standard.[8] Similarly, the Commission determined that proposed Reliability Standard PRC-013-0 was a "fill-in-the-blank" Reliability Standard because,

---

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

[6] *Id.* PP 1529-1533.

[7] *Id.* PP 1534-1540.

[8] *Id.* PP 1517-18, 1520. The Commission used the term "fill-in-the-blank" standards to refer to proposed Reliability Standards that required the regional reliability organizations to develop at a later date criteria for use by users, owners or operators within each region. *Id.* P 297.

although it was intended to ensure that all special protection systems are properly designed, meet performance requirements, and are coordinated with other protection systems by requiring the regional reliability organization to maintain a database of information on special protection systems, NERC had not filed any regional procedures for maintaining the databases.[9] Further, the Commission determined that proposed Reliability Standard PRC-014-0 was a "fill-in-the-blank" Reliability Standard because, while it was proposed to ensure that special protection systems are properly designed, meet performance requirements, and are coordinated with other protection systems by requiring the regional reliability organization to assess and document the operation, coordination, and compliance with NERC Reliability Standards and effectiveness of special protection systems at least once every five years, NERC had not submitted any regional procedures for this assessment and documentation.[10] The Commission stated that it would not approve or remand proposed Reliability Standards PRC-012-0, PRC-013-0 or PRC-014-0 until NERC submitted the additional necessary information to the Commission.[11]

[9] *Id.* PP 1521, 1522, 1524.

[10] *Id.* PP 1525, 1526, 1528.

[11] *Id.* PP 1520, 1524, 1528.

C. Remedial Action Schemes

5. On June 23, 2016, the Commission approved NERC's revision to the NERC Glossary of Terms Used in NERC Reliability Standards (NERC Glossary) that redefines special protection system to have the same definition as remedial action scheme, effective April 1, 2017.[12] The NERC Glossary defines remedial action scheme to mean:

> A scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation (MW and Mvar), tripping load, or reconfiguring a System(s). [Remedial Action Schemes (RAS)] accomplish objectives such as:
>
> - Meet requirements identified in the NERC Reliability Standards;
> - Maintain Bulk Electric System (BES) stability;
> - Maintain acceptable BES voltages;
> - Maintain acceptable BES power flows;
> - Limit the impact of Cascading or extreme events.[13]

The revised remedial action scheme definition also identifies fourteen items that do not individually constitute a remedial action scheme.

[12] *N. Am. Elec. Reliability Corp.*, Docket No. RD16-5-000 (June 23, 2016) (delegated letter order); NERC Glossary, http://www.nerc.com/files/glossary_of_terms.pdf.

[13] NERC Glossary, http://www.nerc.com/files/glossary_of_terms.pdf; *see also Revisions to Emergency Operations Reliability Standards; Revisions to Undervoltage Load Shedding Reliability Standards; Revisions to the Definition of "Remedial Action Scheme" and Related Reliability Standards*, Order No. 818, 153 FERC ¶ 61,228, at PP 24, 31 (2015).

D. NERC Petition and Reliability Standard PRC-012-2

6. On August 5, 2016, NERC submitted a petition seeking Commission approval of proposed Reliability Standard PRC-012-2.[14] NERC contended that Reliability Standard PRC-012-2 is just, reasonable, not unduly discriminatory or preferential, and in the public interest.[15] NERC explained that the intent of Reliability Standard PRC-012-2 is to supersede "pending" Reliability Standards PRC-012-1, PRC-013-1, and PRC-014-1 and to retire and replace currently-effective Reliability Standards PRC-015-1 and PRC-016-1.[16] NERC stated that Reliability Standard PRC-012-2 represents substantial improvements over these Reliability Standards because it streamlines and consolidates existing requirements; corrects the applicability of previously unapproved Reliability Standards; and implements a continent-wide remedial action scheme review program.[17]

7. NERC stated that, in the United States, Reliability Standard PRC-012-2 will apply to reliability coordinators, planning coordinators, and remedial action scheme-entities.

---

[14] Reliability Standard PRC-012-2 is not attached to this Final Rule. The Reliability Standard is available on the Commission's eLibrary document retrieval system in Docket No. RM16-20-000 and is posted on NERC's website, http://www.nerc.com.

[15] NERC Petition at 2.

[16] NERC noted that it submitted "for completeness" revised versions of Reliability Standards PRC-012-1, PRC-013-1, and PRC-014-1 in its petition to revise the definition of remedial action scheme, but NERC did not request Commission approval of the revised Reliability Standards in that proceeding. Id. at 1 n.5.

[17] *Id.* at 12-13.

Reliability Standard PRC-012-2 defines remedial action scheme-entities to include each transmission owner, generation owner, or distribution provider that owns all or part of a remedial action scheme.

8. NERC stated that Reliability Standard PRC-012-2 includes nine requirements that combine all existing (both effective and "pending") Reliability Standards mentioned above into a single, consolidated, continent-wide Reliability Standard to address all aspects of remedial action schemes.[18] NERC explained that all of the requirements in Reliability Standard PRC-012-1 except R2 are now covered in Requirements R1, R2, R3, R4, R5, R6, and R8 of Reliability Standard PRC-012-2.[19] NERC maintained that Reliability Standard PRC-012-1, Requirement R2 is "administrative in nature and does not contribute to reliability."[20] NERC also stated that it established Reliability Standard PRC-012-2, Requirement R9 to replace the mandate in Reliability Standard PRC-013-1 that responsible entities maintain a remedial action scheme database with pertinent technical information for each remedial action scheme.[21] NERC explained that Reliability Standard PRC-012-2, Requirements R4 and R6 cover the review and the

[18] *Id.* at 3.

[19] *Id.* at 40.

[20] *Id.* at 41.

[21] *Id.* at 42.

mandate to take corrective action required by Reliability Standard PRC-014-1.[22] NERC stated that it integrated the performance requirements in Reliability Standard PRC-015-1 into Reliability Standard PRC-012-2, Requirements R1, R2, and R3.[23] NERC also asserted that it integrated the performance requirements in Reliability Standard PRC-016-1 into Reliability Standard PRC-012-2, Requirements R5, R6, and R7.[24]

9. NERC explained how the nine Requirements in Reliability Standard PRC- 012-2 work together and with other Reliability Standards. According to NERC, Requirements R1, R2, and R3, together, establish a process for the reliability coordinator to review new or modified remedial action schemes.[25] The reliability coordinator must complete the review before an entity places a new or functionally modified remedial action scheme into service.

10. Requirement R4 requires the planning coordinator to perform a periodic evaluation of each remedial action scheme within its planning area, at least once every five years.[26] The evaluation must determine, *inter alia*, whether each remedial action scheme: (1) mitigates the system conditions or contingencies for which it was designed;

---

[22] *Id.*at 43.

[23] *Id.* at 43-44.

[24] *Id.* at 44-45.

[25] *Id.* at 15-18.

[26] *Id.* at 18-22.

and (2) avoids adverse interactions with other remedial action scheme and protection systems. Requirement R4, Part 4.1.3 footnote 1 defines a certain subset of remedial action schemes as "limited impact." Requirement R4, Part 4.1.3 footnote 1 states: "A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations."[27] Further, Requirement R4, Parts 4.1.3, 4.1.4, and 4.1.5 provide certain exceptions to "limited impact" remedial action schemes. For example, Part 4.1.5 states that:

> Except for limited impact RAS, a single component failure in the RAS, when the RAS is intended to operate does not prevent the BES from meeting the same performance requirements (defined in Reliability Standard TPL-001-4 or its successor) as those required for the events and conditions for which the RAS is designed.[28]

NERC explained that Requirement R4 "does not supersede or modify [planning coordinator] responsibilities under Reliability Standard TPL-001-4."[29] NERC continued that even though Part 4.1.5 exempts "limited impact" remedial action schemes from certain aspects of Reliability Standard PRC-012-2, Requirement R4 does not exempt

[27] *Id.* at 19 & n.44.

[28] *Id.* at 19.

[29] *Id.* at 28.

"limited impact" remedial actions schemes from meeting each of the performance requirements in Reliability Standard TPL-001-4.[30]

11. NERC stated that prior to development of Reliability Standard PRC-012-2, two NERC Regions, the Northeast Power Coordinating Council (NPCC) and the Western Electric Coordinating Council (WECC), used their own remedial action scheme classification regimes to identify remedial action schemes that would meet criteria similar to those for remedial action schemes described as "limited impact" in Reliability Standard PRC-012-2.[31] NERC continued that the standard drafting team identified the Local Area Protection Scheme (LAPS) classification in WECC and the Type III classification in NPCC as consistent with the "limited impact" designation.[32] According to NERC, remedial action schemes implemented prior to the effective date of Reliability Standard PRC-012-2 that have gone through the regional review processes of WECC or NPCC and that are classified as either a LAPS by WECC or a Type III by NPCC would be considered a "limited impact" remedial action scheme for purposes of Reliability Standard PRC-012-2.[33]

[30] *Id.* at 28-29.

[31] *Id.* at 25.

[32] *Id.*at 25-26.

[33] *Id.* at 26.

12. Requirements R5, R6, and R7 pertain to the analysis of each remedial action scheme operation or misoperation.[34] A remedial action scheme-entity must perform an analysis of each remedial action scheme operation or misoperation and provide the results to the reviewing reliability coordinator. Further, the remedial action scheme-entity must develop and submit a corrective action plan to the reviewing reliability coordinator after learning of a deficiency with its remedial action scheme, implement the corrective action plan, and update it as necessary. Requirement R8 requires periodic testing of remedial action scheme performance: every six years for normal remedial action schemes and every 12 years for "limited impact" remedial action schemes.[35] Requirement R9 requires the reliability coordinator to annually update its remedial action scheme database.[36]

13. NERC proposed an implementation plan that includes an effective date for Reliability Standard PRC-012-2 that is the first day of the first calendar quarter that is thirty-six months after the date that the Commission approves the Reliability Standard. Concurrent with the effective date, the implementation plan calls for the retirement of currently-effective Reliability Standards PRC-015-1 and PRC-016-1 and withdrawal of "pending" Reliability Standards PRC-012-1, PRC-013-1, and PRC-014-1.

[34] *Id.* at 29-34.

[35] *Id.* at 34-36.

[36] *Id.* at 36-38.

E. Notice of Proposed Rulemaking

14. On January 19, 2017, the Commission issued a Notice of Proposed Rulemaking proposing to approve Reliability Standard PRC-012-2.[37] The NOPR also proposed to clarify that, consistent with NERC's representation in its petition, Reliability Standard PRC-012-2 will not modify or supersede any system performance obligations under Reliability Standard TPL-001-4.[38] In addition, the NOPR proposed to approve the associated violation risk factors and violation severity levels, implementation plan, and effective date proposed by NERC.[39] The NOPR further proposed to approve the withdrawal of "pending" Reliability Standards PRC-012-1, PRC-013-1, and PRC-014-1 and retirement of currently-effective Reliability Standards PRC-015-1 and PRC-016-1, as proposed by NERC.[40]

15. In response to the NOPR, entities filed seven sets of 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.

[37] *Remedial Action Schemes Reliability Standard*, Notice of Proposed Rulemaking, 82 FR 9702 (Jan. 19, 2017), 158 FERC ¶ 61,042 (2017) (NOPR).

[38] NOPR, 158 FERC ¶ 61,042 at P 16.

[39] *Id.* P 14.

[40] *Id.*

II. Discussion

16. Pursuant to section 215(d)(2) of the FPA, we hereby approve Reliability Standard PRC-012-2.[41] Reliability Standard PRC-012-2 promotes efficiency and clarity by addressing all aspects of remedial action schemes in a single, continent-wide Reliability Standard. Reliability Standard PRC-012-2 enhances reliability by assigning specific remedial action scheme responsibilities to appropriate functional entities. Further, Reliability Standard PRC-012-2 improves reliability by establishing a centralized process to review new or modified remedial action schemes prior to implementation, by requiring periodic evaluations, tests, and operational analyses of each remedial action scheme, and by requiring an annual update of an area-wide remedial action scheme database. We determine that Reliability Standard PRC-012-2 satisfies the relevant directives in Order No. 693 for the ERO to provide additional information regarding review procedures for remedial action schemes (then called special protection systems) and to establish continent-wide uniformity.[42]

17. We also approve the associated violation risk factors and violation severity levels, implementation plan, and effective date proposed by NERC. In addition, we approve, upon the effective date of Reliability Standard PRC-012-2, the withdrawal of pending Reliability Standards PRC-012-1, PRC-013-1, and PRC-014-1 and the retirement of

[41] 16 U.S.C. 824o(d)(2).

[42] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at PP 297-298, 1517-1520.

currently-effective Reliability Standards PRC-015-1 and PRC-016-1 due to their consolidation with proposed Reliability Standard PRC-012-2.

A. Impact of Reliability Standard PRC-012-2 on Compliance with Reliability Standard TPL-001-4

NOPR

18. The NOPR sought comments on its proposal to clarify that Reliability Standard PRC-012-2 will not modify or supersede any system performance obligation under Reliability Standard TPL-001-4. The NOPR also sought comments on the processes used to ensure LAPS or Type III remedial action schemes' compliance with Reliability Standard TPL-001-4 prior to the effective date of Reliability Standard PRC-012-2.

Comments

19. NERC, Joint ISOs, and the EEI support the Commission's proposal to approve Reliability Standard PRC-012-2 with a clarification that it does not modify or supersede any system performance obligations under Reliability Standard TPL-001-4.[43] NERC states that Reliability Standard PRC-012-2 merely adds design, implementation, and review requirements ensuring that remedial action schemes enhance reliability and do not introduce unintentional or unacceptable reliability risks.[44] NERC and Joint ISOs state that Reliability Standard PRC-012-2 does not supersede or modify the system performance requirements of Reliability Standard TPL-001-4 because responsible

[43] NERC Comments at 4; Joint ISO Comments at 2; EEI Comments at 4.

[44] NERC Comments at 5.

entities must still assume that all remedial action schemes operate correctly, guaranteeing a non-consequential load loss by less than 75 MW.[45] Joint ISOs believe that no clarification to Reliability Standard PRC-012-2 is necessary; but if the Commission determines that some clarification is necessary, the Commission may confirm that under Reliability Standard TPL-001-4, responsible entities can assume that all remedial action schemes operate as designed.[46] EEI states that while it is unlikely that the exceptions in Reliability Standard PRC-012-2 would be interpreted by industry as exempting any of the performance requirements in Reliability Standard TPL-001-4, EEI is supportive of the proposed clarification since such clarification would remove any ambiguity.[47]

20. NESCOE contends that, absent confirmation that Reliability Standard TPL-001-4 allows responsible entities to assume that all remedial action schemes operate properly, a clarification that Reliability Standard PRC-012-2 does not modify or supersede any system performance obligations under Reliability Standard TPL-001-4 may be misinterpreted by entities, requiring actions that would increase material costs without

[45] *Id.* at 5; Joint ISO Comments at 2.

[46] Joint ISO Comments at 2.

[47] EEI Comments at 4.

benefit.[48] NESCO states that reliability gains must be measured against the risk and cost associated with any standard.[49]

21. NERC states that LAPS in WECC and Type III remedial actions schemes in NPCC must be compliant with Reliability Standard TPL-001-4 before and after the effective date of proposed Reliability Standard PRC-012-2.[50] According to NERC, Reliability Standard TPL-001-4 does not distinguish between different types of remedial action schemes or exempt LAPS or Type III remedial action schemes from any of the performance requirements.[51] NERC and Joint ISOs state that additional regional controls that maintain remedial action scheme compliance with the performance requirements of Reliability Standard TPL-001-4 are in place.[52]

22. EEI questions the relevancy of asking the industry to comment on WECC LAPS or NPCC Type III remedial action schemes reclassification as "limited impact" remedial action schemes.[53] EEI contends that once the Commission approves Reliability Standard

[48] NESCO Comments at 2.

[49] *Id.*

[50] NERC Comments at 5.

[51] *Id.* at 6.

[52] *Id.*; Joint ISO Comments at 3.

[53] EEI Comments at 5.

PRC-012-2, WECC and NPCC must be compliant regardless. EEI believes that insights into processes ensuring compliance with Reliability Standard PRC-012-2 are irrelevant.[54]

Commission Determination

23. We adopt our NOPR proposal and clarify that Reliability Standard PRC-012-2 does not modify or supersede any system performance obligations under Reliability Standard TPL-001-4. We agree with and, thus, adopt NERC's explanation:

> Nothing in proposed Reliability Standard PRC-012-2 or the designation of a RAS as "limited impact" exempts an entity from meeting its performance requirements under [Reliability Standard] TPL-001-4, including the requirement that Non-Consequential Load Loss may not exceed 75 MW for certain Category P1, P2, or P3 contingencies, as provided in Table 1 and footnote 12 of TPL-001-4.
>
> In performing the assessments required pursuant to Reliability Standard TPL-001-4, an entity must consider all RAS, whether designated as "limited impact" or not. While Reliability Standard TPL-001-4, Requirement R2, Part 2.7.1 recognizes that entities may use a RAS as a method for meeting the performance obligations of Table 1, TPL-001-4 does not distinguish between different types of RAS. As such, entities must satisfy the performance requirements of TPL-001-4 considering the actions of "limited impact" RAS and non-limited impact RAS alike.[55]

[54] *Id.*

[55] NERC Comments at 5. In response to the requests by Joint ISOs and NESCOE for confirmation that Reliability Standard TPL-001-4 allows responsible entities to assume that all remedial action schemes operate properly, the Commission declines to interpret Reliability Standard TPL-001-4 in this proceeding. However, this Final Rule approving Reliability Standard PRC-012-2 in no way modifies the requirements of Reliability Standard TPL-001-4 or the compliance obligations associated with Reliability Standard TPL-001-4.

This clarification should help entities avoid confusion regarding compliance obligations when implementing PRC-012-2.

24. In addition, we accept NERC's assurance that LAPS in WECC and Type III remedial actions schemes in NPCC must be compliant with Reliability Standard TPL-001-4 before and after the effective date of proposed Reliability Standard PRC-012-2.[56]

B. Definition of "Limited Impact" Remedial Action Schemes

NOPR

25. The NOPR sought comment on whether NERC should define the term "limited impact" remedial action schemes in the NERC Glossary.

Comments

26. NERC, Joint ISOs, and EEI contend that NERC should not define the term "limited impact" remedial action scheme in the NERC Glossary.[57] NERC states that it typically develops terms in the NERC Glossary for one of two reasons: "(1) to establish a single meaning for a term or concept used across several different Reliability Standards or multiple times within a single Reliability Standard, or (2) to provide for a more

[56] We note that WECC's and NPCC's remedial action scheme criteria and associated regional terms found in the "Technical Justification" section of Reliability Standard PRC-012-2 were not submitted for approval by NERC and as such are not part of this proceeding.

[57] NERC Comments at 8; Joint ISO Comments at 3; EEI at 5.

readable standard by creating a shorthand reference to avoid unnecessary repetition."[58] NERC contends that neither reason exists for "limited impact" remedial action schemes.[59]

27. NERC and EEI maintain that remedial action schemes vary widely in complexity and impact on the bulk electric system.[60] NERC and EEI explain that NERC should not define "limited impact" remedial action schemes because not all remedial action schemes impact the bulk electric system similarly and the diversity of remedial action schemes makes it difficult to establish a common definition for North America.[61]

28. NERC, Joint ISOs, and EEI assert that other comprehensive lists may establish a baseline definition for "limited impact" remedial action schemes.[62] Joint ISOs note that the performance criteria described in Reliability Standard PRC-012-2, Requirement 4.1.3, footnote 1 provide an adequate level of guidance.[63] MISO contends that NERC need not define "limited impact" remedial action scheme in the NERC Glossary.[64]

---

[58] NERC Comments at 8.

[59] *Id.*

[60] NERC Comments at 9; EEI Comments at 5.

[61] *Id.*

[62] NERC Comments at 9; Joint ISO Comments at 3; EEI Comments at 6.

[63] Joint ISO Comments at 3-4.

[64] MISO Comments at 6.

29. Bonneville and ITC contend that NERC should define the term "limited impact" remedial action schemes in the NERC Glossary.[65] Bonneville states that the footnote in Reliability Standard PRC-012-2 only reiterates the substantive requirements of "limited impact" remedial action schemes under Requirement R4.3.1 and does not clarify how "limited impact" remedial action schemes differ from normal remedial action schemes.[66] Bonneville proposes the following definition for "limited impact" remedial action schemes:

> A remedial action scheme whose operation or misoperation only affects the local area defined by the RAS-entity that owns all of part of the remedial action scheme and does not affect the BES of any adjacent Transmission Owners, Transmission Operators, Generation Owners, or Generation Operators.[67]

ITC also states that the Commission should issue a directive to NERC to define "limited impact" remedial action schemes in the NERC Glossary.[68] ITC states that doing so avoids confusion while ensuring consistency, facilitates the use of the term in other Reliability Standards, and enhances the overall usefulness of the NERC Glossary.[69]

---

[65] Bonneville Comments at 2; ITC Comments at 1.

[66] Bonneville Comments at 2.

[67] *Id.*

[68] ITC Comments at 1.

[69] *Id.* at 2.

Commission Determination

30. We determine not to require NERC to define "limited impact" remedial action schemes in the NERC Glossary. We agree with NERC, Joint ISOs, and EEI that a definition of "limited impact" remedial action schemes is unnecessary at this time given the diversity among the different types, functions, and placements of remedial action schemes across North America. In addition, only Reliability Standard PRC-012-2 uses the term "limited impact" remedial action schemes, thus eliminating one of the principal reasons for normally including terms in the NERC Glossary (i.e., to establish a single meaning for a term or concept used across several different Reliability Standards). Should this situation change, the Commission may reconsider this determination.

C. Other Issues

Comments

31. MISO contends that the Commission should not approve Reliability Standard PRC-012-2 as proposed.[70] MISO contends that oversight of remedial action schemes would be difficult for reliability coordinators and planning coordinators when remedial action schemes span multiple footprints.[71] MISO also contends that Reliability Standard PRC-012-2 creates a geographical variation in transmission system characteristics which result in uneven distribution of coordination burden and duplicative work on remedial

[70] MISO Comments at 2.

[71] *Id.*

action schemes.[72] MISO contends that the planning assessment performance requirements in Reliability Standard PRC-012-2 are better placed in Reliability Standard TPL-001-4 to avoid redundancies.[73] Finally, MISO proposes a five-year evaluation of remedial action schemes, which includes a renewal requirement to benefit efficient operations.[74]

32. Bonneville contends that Reliability Standard PRC-012-2, Requirement R2 gives reliability coordinators too much time to complete reviews of remedial action schemes.[75] Bonneville states that Reliability Standard PRC-012-2, Requirement R2 provides reliability coordinators four calendar months to review a remedial action scheme.[76] Bonneville states that in the Western Interconnection, these reviews are currently completed in two weeks. Bonneville continues that Reliability Standard PRC-012-2 allows an additional fourteen weeks for review, which would prevent Bonneville from completing remedial action scheme projects in a timely manner.[77] Bonneville proposes

[72] *Id.* at 3.

[73] *Id.* at 4-5.

[74] *Id.* 6-7.

[75] Bonneville Comments at 2.

[76] *Id.*

[77] *Id.* at 3.

that Reliability Standard PRC-012-2, Requirement R2 should require reliability coordinators to complete their reviews within four weeks.[78]

Commission Determination

33. MISO's opposition to Reliability Standard PRC-012-2 is largely based on perceived "inefficiencies" created by the Reliability Standard because it allegedly lacks regional coordination between reliability coordinators and planning coordinators and because of "redundancies" between PRC-012-2 and Reliability Standard TPL-001-4. We are not persuaded that MISO's concerns justify remanding Reliability Standard PRC-012-2. As discussed above, we determine that the Reliability Standard PRC-012-2 satisfies section 215(d)(2) of the FPA in that it is just, reasonable, not unduly discriminatory or preferential, and in the public interest. MISO accepts that Reliability Standard PRC-012-2 "shifts responsibility from the eight Regional Reliability Organizations (RROs) to Reliability Coordinators and Planning Coordinators" and MISO "agrees that the Reliability Coordinators and Planning Coordinators are best positioned to perform review and evaluation tasks associated with RAS."[79] We also note that other commenters, including Joint ISOs, do not share MISO's concerns and support approval of Reliability Standard PRC-012-2 as drafted.[80] To the extent that MISO continues to

[78] *Id.*

[79] MISO Comments at 2.

[80] Joint ISOs Comments at 1.

believe that improvements should be made to Reliability Standard PRC-012-2, MISO may pursue any modifications through the NERC standards development process.[81]

34. We are not persuaded by Bonneville's comments regarding the period that reliability coordinators have to review remedial action schemes. NERC stated that Reliability Standard PRC-012-2, Requirement R2 establishes a comprehensive, consistent review process that includes a detailed checklist that reliability coordinators must use to identify design and implementation aspects of the remedial action schemes that are critical to an effective framework.[82] NERC also stated that allowing four months to complete this detailed review is consistent with industry practice, provides adequate time for a complete review, and includes additional flexibility for unique or unforeseen circumstances.[83] While four calendar months may be longer than what is typical in the Western Interconnection, we determine that NERC's proposal is reasonable because it provides a single, consistent, continent-wide timeframe for reviews. Moreover, as

[81] With respect to MISO's proposal that each remedial action scheme be renewed every five years, NERC explained that Reliability Standard PRC-012-2, Requirement R4 provides for periodic remedial action scheme evaluations (i.e., at least every five years) by planning coordinators that will result in one of three determinations: (1) affirmation that the existing remedial action scheme is effective; (2) identification of changes needed to the existing remedial action scheme; or (3) justification for remedial action scheme retirement. NERC Petition at 21. Provided that the remedial action scheme is determined to be effective, is made effective, or retired, we see no reliability reason to direct inclusion of an additional renewal sub-requirement.

[82] NERC Petition at 17.

[83] *Id.*

Bonneville recognizes, Reliability Standard PRC-012-2, Requirement R2 permits entities to use a mutually agreed upon schedule instead of the four-month default timeline provided for in Requirement R2. Accordingly, Bonneville's request is denied on this issue.

III. Information Collection Statement

35. The collection of information addressed in this final rule is subject to review by the Office of Management and Budget (OMB) under section 3507(d) of the Paperwork Reduction Act of 1995.[84] OMB's regulations require approval of certain information collection requirements imposed by agency rules.[85] 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.

36. Public Reporting Burden: The number of respondents below is based on an examination of the NERC compliance registry for reliability coordinators, planning coordinators, transmission owners, generation owners, and distribution providers and an estimation of how many entities from that registry will be affected by the proposed Reliability Standard. At the time of Commission review of Reliability Standard PRC-012-2, 15 reliability coordinators, 71 planning coordinators, 328 transmission

[84] 44 U.S.C. 3507(d).

[85] 5 CFR 1320.11.

owners, 930 generation owners, and 367 distribution providers in the United States were registered in the NERC compliance registry. However, under NERC's compliance registration program, entities may be registered for multiple functions, so these numbers incorporate some double counting. The Commission notes that many generation sites share a common generation owner.

37. Reliability Standards PRC-015-1 and PRC-016-1 are in the Reliability Standards approved in FERC-725A, (OMB Control No. 1902-0244). Reliability Standards PRC-015-1 and PRC-016-1 will be retired when Reliability Standard PRC-012-2 becomes effective, which will reduce the burden in FERC-725A.[86]

38. Reliability Standard PRC-012-2 sets forth Requirements for remedial action schemes to ensure that remedial action schemes do not introduce unintentional or unacceptable reliability risks to the bulk electric system and are coordinated to provide the service to the system as intended. Reliability Standard PRC-012-2 improves upon the existing Reliability Standards because it removes ambiguity in NERC's original "fill-in-the-blank" Reliability Standards by assigning responsibility to appropriate functional entities. Reliability Standard PRC-012-2 also streamlines and consolidates the remedial action scheme Reliability Standards into one clear, effective Reliability Standard under Information Collection FERC-725G.

[86] The Commission is being conservative and not subtracting hours at this time from FERC-725A.

39. The following table illustrates the estimated burden to be applied to FERC-725G information collection.[87]

FERC-725G in RM16-20-000 (Mandatory Reliability Standards: Reliability Standard PRC-012-2)					
Requirement and Respondent Category for PRC-012-2	**Number of Respondents (1)**	**Number of Responses per Respondent (2)**	**Total Number of Responses (1)*(2)=(3)**	**Average Burden Hours & Cost per Response[88] (4)**	**Annual Burden Hours & Total Annual Cost (3)*(4)=(5)**
R1. Each RAS-entity (TO, GO, DP)	1,595	1	1,595	(Eng.) 24 hrs. ($1,543); (R.K.) 12 hrs. ($453)	57,420 hrs. (38,280 Eng., 19,140 R.K.); $3,183,556 ($2,461,021 Eng., $722,535 R.K.)
R2. Each Reliability Coordinator	15	1	15	(Eng.) 16 hrs. ($1,029); (R.K.) 4 hrs. ($151)	300 hrs. (240 Eng., 60 R.K.); $17,695 ($15,430 Eng., $2,265 R.K.)
R4. Each Planning Coordinator	71	1	71	(Eng.) 16 hrs. ($1,029); (R.K.) 4 hrs. ($151)	1,420 hrs. (1,136 Eng., 284 R.K.); $85,754 ($73,033 Eng., $10,721 R.K.)
R5, R6, R7, and R8. Each RAS-entity (TO, GO, DP)	1,595	1	1,595	(Eng.) 24 hrs. ($1,543); (R.K.) 12 hrs. ($453)	57,420 hrs. (38,280 Eng., 19,140 R.K.); $3,183,556 ($2,461,021 Eng., $722,535 R.K.)
R9. Each Reliability Coordinator	15	1	15	(Eng.) 10 hrs. ($653); (R.K.) 4 hrs. ($151)	210 hrs. (150 Eng., 60 R.K.); $11,909 ($9,644 Eng., $2,265 R.K.)
TOTAL			**3,291**		**116,770 hrs. (78,086 Eng., 38,684 R.K.); $6,480,470 ($5,020,149 Eng.; $1,460,321 R.K.)**

[87] In the burden table, engineering is abbreviated as "Eng." and record keeping is abbreviated as "R.K."

[88] The estimates for cost per response are derived using the following formula: Burden Hours per Response * $/hour = Cost per Response. The $64.29/hour figure for an engineer and the $37.75/hour figure for a record clerk are based on the average salary plus benefits data from the Bureau of Labor Statistics.

Title: FERC-725A (Mandatory Reliability Standards); FERC-725G (Mandatory Reliability Standards: PRC-012-2)

Action: Revision to existing collections.

OMB Control No: 1902-0244 (FERC-725A); 1902-0252 (FERC-725G)

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

Frequency of Responses: Annually

Necessity of the Information: Reliability Standard PRC-012-2 sets forth Requirements for remedial action schemes to ensure that remedial action schemes do not introduce unintentional or unacceptable reliability risks to the bulk electric system and are coordinated to provide the service to the system as intended.

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.

40. 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].

41. Comments concerning the information collection in this Final Rule and the associated burden estimates should 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-725A and FERC-725G and the docket number of this Final Rule, Docket No. RM16-20-000, in your submission.

IV. Environmental Analysis

42. 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.[89] The action proposed here falls within the categorical exclusion in the Commission's regulations for rules that are clarifying, corrective or procedural, for information gathering, analysis, and dissemination.[90]

V. Regulatory Flexibility Act

43. The Regulatory Flexibility Act of 1980 (RFA) generally requires a description and analysis of proposed rules that will have significant economic impact on a substantial number of small entities.[91]

44. In the NOPR, the Commission proposed that Reliability Standard PRC-012-2 will apply to approximately 1681 entities in the United States.[92] The Commission did not receive any comments on the impact on small entities. Comparison of the applicable entities with the Commission's small business data indicates that approximately 1,025 are

---

[89] *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).

[90] 18 CFR 380.4(a)(2)(ii).

[91] 5 U.S.C. 601-612.

[92] NOPR, 158 FERC ¶ 61,042 at P 26.

small entities or 61 percent of the respondents affected by proposed Reliability Standard PRC-012-2.[93] The Commission estimates for these small entities, Reliability Standard PRC-012-2 may need to be evaluated and documented every five years with a cost of $6,322 for each evaluation. The Commission views this as a minimal economic impact for each entity. Accordingly, the Commission certifies that Reliability Standard PRC-012-2 will not have a significant economic impact on a substantial number of small entities.

VI. Document Availability

45. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (http://www.ferc.gov) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington DC 20426.

46. From the Commission's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this

[93] The Small Business Administration sets the threshold for what constitutes a small business. Public utilities may fall under one of several different categories, each with a size threshold based on the company's number of employees, including affiliates, the parent company, and subsidiaries. For the analysis in this rulemaking, we apply a 500 employee threshold for each affected entity. Each entity is classified as Electric Bulk Power Transmission and Control (NAICS code 221121).

document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

47. User assistance is available for eLibrary and the Commission's website during normal business hours from FERC Online Support at 202-502-6652 (toll free at 1-866-208-3676) or e-mail at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202)502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

VII. Effective Date and Congressional Notification

48. The final rule is effective [**INSERT DATE 60 days from publication in FEDERAL REGISTER**]. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this rule is not a "major rule" as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996. This final rule is being submitted to the Senate, House, and Government Accountability Office.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

Appendix

Bonneville Power Administration (Bonneville)

Edison Electric Institute (EEI)

International Transmission Company d/b/a ITC Transmission, Michigan Electric Transmission Company, LLC, ITC Midwest LLC and ITC Great Plains, LLC (together, ITC)

Midcontinent Independent System Operator, Inc. (MISO)

New England States Committee on Electricity (NESCOE)

New York Independent System Operator, Independent Electricity System Operator, ISO New England, Inc. and Electric Reliability Council of Texas, Inc. (together, Joint ISOs)

North American Electric Reliability Corporation (NERC)

160 FERC ¶ 61,072
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 40

[Docket No. RM17-12-000]

Emergency Preparedness and Operations Reliability Standards

(September 20, 2017)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission proposes to approve Emergency Preparedness and Operations (EOP) Reliability Standards EOP-004-4 (Event Reporting), EOP-005-3 (System Restoration from Blackstart Resources), EOP-006-3 (System Restoration Coordination), and EOP-008-2 (Loss of Control Center Functionality).

DATES: Comments are due **[INSERT DATE 60 days after publication in the FEDERAL REGISTER**].

ADDRESSES: Comments, identified by docket number, may be filed in the following ways:

- Electronic Filing through http://www.ferc.gov. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format.

- Mail/Hand Delivery: Those unable to file electronically may mail or hand-deliver comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE, Washington, DC 20426.

Instructions: For detailed instructions on submitting comments and additional information on the rulemaking process, see the Comment Procedures Section of this document.

FOR FURTHER INFORMATION CONTACT:

E. Nick Henery (Technical Information)
Office of Electric Reliability, Division of Reliability Standards
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426
Telephone: (202) 502-8636
Nick.Henery@ferc.gov

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

SUPPLEMENTARY INFORMATION:

160 FERC ¶ 61,072
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Emergency Preparedness and Operations Reliability Standards — Docket No. RM17-12-000

NOTICE OF PROPOSED RULEMAKING

(September 20, 2017)

1. Under section 215 of the Federal Power Act (FPA),[1] the Commission proposes to approve proposed Emergency Preparedness and Operations (EOP) Reliability Standards EOP-004-4 (Event Reporting), EOP-005-3 (System Restoration from Blackstart Resources), EOP-006-3 (System Restoration Coordination), and EOP-008-2 (Loss of Control Center Functionality), submitted by the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization (ERO). The proposed EOP Reliability Standards are intended to: (1) provide accurate reporting of events to NERC's event analysis group to analyze the impact on the reliability of the bulk electric system (EOP-004-4); (2) delineate the roles and responsibilities of entities that support system restoration from blackstart resources which generate power without the support of the grid (EOP-005-3); (3) clarify the procedures and coordination requirements for reliability coordinator personnel to execute system restoration processes

[1] 16 U.S.C. 824(o). The proposed Reliability Standards are available on the Commission's eLibrary document retrieval system in Docket No. RM17-12-000 and on the NERC website, www.nerc.com.

(EOP-006-3); and (4) refine the required elements of an operating plan used to continue reliable operations of the bulk electric system if that primary control functionality is lost (EOP-008-2). The Commission also proposes to approve the associated violation risk factors, violation severity levels, implementation plans, and effective dates. In addition, the Commission proposes to retire currently-effective Reliability Standards EOP-004-3, EOP-005-2, EOP-006-2, and EOP-008-1 immediately prior to the effective dates of the proposed EOP Reliability Standards.

I. Background

A. Regulatory Background

2. Section 215 of the FPA requires a Commission-certified ERO to develop mandatory and enforceable Reliability Standards that are subject to Commission review and approval. The Commission may approve, by rule or order, a proposed Reliability Standard or modification to a Reliability Standard if it determines that the Reliability Standard is just, reasonable, not unduly discriminatory or preferential and in the public interest.[2] Once approved, the Reliability Standards may be enforced by the ERO, subject to Commission oversight, or by the Commission independently.[3] Pursuant to section 215 of the FPA, the Commission established a process to select and certify an ERO,[4] and

[2] *Id.* 824o(d)(2).

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

[4] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability*

subsequently certified NERC.[5] On March 16, 2007, the Commission issued Order No. 693, approving 83 of the 107 Reliability Standards filed by NERC, including the initial EOP Reliability Standards.[6]

B. NERC Petition

3. According to NERC, the proposed EOP Reliability Standards: (1) streamline the currently-effective EOP Standards; (2) remove redundancies and other unnecessary language while making the Reliability Standards more results-based;[7] and (3) address the Commission's concern articulated in Order No. 749 regarding system restoration training.[8] The proposed EOP Reliability Standards are summarized below.

Standards, Order No. 672, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[5] *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062, *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006), *aff'd sub nom. Alcoa, Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

[6] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, 72 FR 16416 (Apr. 4, 2007), FERC Stats. & Regs. ¶ 31,242, at P 297, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

[7] *North American Electric Reliability Corp.*, 138 FERC ¶ 61,193, at P 81 (March 2012 Order), *order on reh'g and clarification*, 139 FERC ¶ 61,168 (2012). The March 2012 Order approved a NERC process to identify requirements that could be removed from Reliability Standards without impacting the reliability of the interconnected transmission network.

[8] *System Restoration Reliability Standards*, Order No. 749, 134 FERC ¶ 61,215, at PP 18, 24 (2011).

Proposed Reliability Standard EOP-004-4

4. Proposed Reliability Standard EOP-004-4 requires reporting of events by responsible entities. The reportable events under the proposed Reliability Standard are collected and used to examine the underlying causes of events; track subsequent corrective action to prevent recurrence of such events; and develop lessons learned for industry. While these events arise in the real-time operation time horizon and require action by responsible entities within one hour or less to preserve the reliability of the bulk electric system, Reliability Standard EOP-004-3 is not intended to require system operators to report the events during the real-time operation time horizon, but rather can be reported six to twenty four hours after the event.

5. NERC states that the proposed Reliability Standard modifications are designed to eliminate redundant reporting of a single event by multiple entities; assign reporting requirements to appropriate entities; clarify the threshold reporting for a given event; and where appropriate, align the reportable events and thresholds identified in Attachments 1 and 2 of the proposed Reliability Standard with the Department of Energy's (DOE) Form OE-417. NERC states that the proposed Reliability Standard improves the quality of information received by the ERO as well as the quality of analysis that the ERO produces from this information to assess the greatest risk to the bulk electric system.

6. Attachment 1 of the proposed Reliability Standard identifies the types and thresholds of reportable events that have the potential to impact the reliability of the bulk electric system. Attachment 2 is a reporting template for entities to report the types and thresholds of events identified in Attachment 1 to NERC. To the extent that DOE's

Form OE-417 reflects similar event types and thresholds of events as Attachment 2, responsible entities may submit Form OE-417 in lieu of Attachment 2.[9]

7. Under currently-effective Reliability Standard EOP-004-3, Attachment 1, reliability coordinators must report to NERC when they operate outside of their interconnection reliability operating limit (IROL) for greater than "T_V" (defined as less than or equal to 30 minutes). NERC proposes to eliminate the IROL violation reporting requirement in Attachment 1 of proposed Reliability Standard EOP-004-4 because, according to NERC, EOP-004 is primarily a tool for trending analysis and developing lessons learned and not designed to be a real-time tool.

8. NERC states that the standard drafting team concluded that any real-time reporting to NERC or Regional Entities (i.e., contemporaneous with the transmission operator's notification of the IROL to the reliability coordinator) should be addressed in the TOP Reliability Standards, which deal with the real-time operations time horizon. In its petition, NERC identifies Reliability Standard TOP-001-3 (Transmission Operations) as the appropriate Reliability Standard for reporting such real-time events. NERC states that the purpose of Reliability Standard TOP-001-3 is to prevent instability, uncontrolled separation, or cascading outages that adversely impact the reliability of an interconnection by ensuring prompt action to prevent or mitigate such occurrences. Specifically, Reliability Standard TOP-001-3, Requirement R12 provides that "[e]ach

[9] Under the current practice, the ERO will accept DOE's Form OE-417 report in lieu of Attachment 2 to Reliability Standard EOP-004-3 to the extent a given event type and threshold align.

Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated T_V." Separately, NERC identifies Reliability Standard TOP-007-0 (Reporting System Operating Limit (SOL) and IROL Violations), Requirement R2, which states that "[f]ollowing a Contingency or other event that results in an IROL violation, the Transmission Operator shall return its transmission system to within IROL as soon as possible, but not longer than 30 minutes." Finally, NERC cites Requirement R3 of Reliability Standard IRO-009-2 (Reliability Coordinator Actions to Operate within IROLs), which states that "[e]ach Reliability Coordinator shall act or direct others to act so that the magnitude and duration of an IROL exceedance is mitigated within the IROL T_V, as identified in the Reliability Coordinator's Real-time monitoring or Real-time Assessment."

Proposed Reliability Standard EOP-005-3

9. The purpose of proposed Reliability Standard EOP-005-3 is to ensure plans, facilities, and personnel are prepared to enable system restoration from blackstart resources to ensure reliability is maintained during restoration and priority is placed on restoring the interconnection. NERC states that proposed Reliability Standard EOP-005-3 improves the existing version of the Reliability Standard by: (1) emphasizing the need for transmission operators to develop and use restoration plans relating to blackstart resources; (2) retiring redundant or administrative requirements; and (3) clarifying requirements for revising and testing restoration plans.

Proposed Reliability Standards EOP-006-3

10. The purpose of proposed Reliability Standard EOP-006-3 is to establish how personnel should prepare, execute, and coordinate system restoration processes to maintain reliability and to restore the Interconnection. NERC states that proposed Reliability Standard EOP-006-3 improves upon the existing version of the standard by emphasizing the need for reliability coordinators to develop and use their restoration plans and clarifying requirements for training and coordination of restoration plans amongst reliability coordinators.

Proposed Reliability Standard EOP-008-2

11. The purpose of proposed Reliability Standard EOP-008-2 is to ensure continued reliable operations of the bulk electric system if a control center becomes inoperable. NERC states that proposed Reliability Standard EOP-008-2 improves upon the existing Reliability Standard by clarifying the required contents of an operating plan used by reliability coordinators, balancing authorities and transmission operators.

II. Discussion

12. Pursuant to section 215(d) of the FPA, the Commission proposes to approve the proposed EOP Reliability Standards as just, reasonable, not unduly discriminatory or preferential and in the public interest. The Commission also proposes to approve the associated violation risk factors, violation severity levels, implementation plans, and effective dates. Further, the Commission proposes to retire currently-effective Reliability Standards EOP-004-3, EOP-005-2, EOP-006-2, and EOP-008-1 immediately prior to the effective dates of the proposed EOP Reliability Standards.

13. Proposed Reliability Standard EOP-004-4 will enhance reliability by assigning reporting to appropriate entities; and clarifying the threshold reporting for a given event. In addition, aligning the reportable events and thresholds identified in Attachment 1 of the proposed Reliability Standard with DOE's Form OE-417 should improve the quality of information received by NERC and the quality of analysis that NERC produces to assess the greatest risks to the bulk electric system. Further, proposed Reliability Standard EOP-004-4 promotes efficiency and clarity by eliminating redundant reporting of a single event by multiple entities.

14. Proposed Reliability Standards EOP-005-3, EOP-006-3, and EOP-008-2 will enhance reliability by delineating the roles and responsibilities of entities that support system restoration from blackstart resources; clarifying the procedures and coordination requirements for reliability coordinator personnel to execute system restoration processes; and refining operating plan elements if primary control functionality is lost.

15. Finally, while we are not persuaded that the three Reliability Standards identified by NERC require the reporting of IROL information,[10] we propose to accept NERC's

[10] While Reliability Standard TOP-007-0, Requirement R1 mandates reporting of SOL and IROL violations, that Reliability Standard was retired recently. *Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards*, Order No. 817, 153 FERC ¶ 61,178 (2015). Reliability Standard TOP-001-3, Requirement R12 requires transmission operators not to operate outside of IROL T_V. The requirement's associated compliance measure, however, only requires transmission operators to "make available evidence to show that for any occasion in which it operated outside any identified [IROL], the continuous duration did not exceed its associated IROL T_V."[10] While this information may be similar to what would be found in an IROL T_V exceedance report under currently-effective

proposed retirement of currently-effective Reliability Standard EOP-004-3. Currently NERC voluntarily shares IROL T_V exceedance information with Commission staff so that Commission staff can monitor the transmission system and identify reliability trends. We understand that NERC will continue to receive IROL T_V exceedance information and share it with Commission staff even after the proposed retirement of EOP-004-3.

III. Information Collection Statement

16. The Office of Management and Budget (OMB) regulations require that OMB approve certain reporting and recordkeeping (collections of information) imposed by an agency.[11] Upon approval of a collection(s) of information, OMB will assign an OMB control number and expiration date. Respondents subject to the filing requirements of this rule will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number.

17. The Commission is submitting these reporting and recordkeeping requirements to OMB for its review and approval under section 3507(d) of the Paper Reduction Act of 1995, 44 U.S.C. § 3507(d) (2012). Comments are solicited on the Commission's need for this information, whether the information will have practical utility, the accuracy of the provided burden estimate, ways to enhance the quality, utility, and clarity of the

Reliability Standard EOP-004-3, Reliability Standard TOP-001-3 does not require responsible entities to report the exceedance. The same can be said of Reliability Standard IRO-009-2.

[11] 5 CFR 1320.11.

information to be collected, and any suggested methods for minimizing the respondent's burden, including the use of automated information techniques.

18. This Notice of Proposed Rulemaking proposes to approve revisions to Reliability Standards EOP-004-4 (Event Reporting), EOP-005-3 (System Restoration from Blackstart Resources), EOP-006-3 (System Restoration Coordination), and EOP-008-2 (Loss of Control Center Functionality).

19. Public Reporting Burden: Our estimate below regarding the number of respondents is based on the NERC Compliance Registry as of April 7, 2017. The following estimates relate to the requirements for this Notice of Proposed Rulemaking in Docket No. RM17-12-000.

RM17-12-000 (Emergency Preparedness and Operations Reliability Standards)						
	Number of Respondents (1)	**Annual Number of Responses per Respondent (2)**	**Total Number of Responses (1)*(2)=(3)**	**Average Burden & Cost Per Response[12] (4)**	**Total Annual Burden & Total Annual Cost[13] (3)*(4)=(5)**	**Cost per Respondent ($) (5)÷(1)**
EOP-008-2						
One-time Review and Revision of Plan	215	1	215	20 hrs. (Eng.); $1,286	4,300 hrs. (Eng.); $276,447	$1,286 (Eng.)

[12] Eng.: engineering; R.K.: record-keeping.

[13] The estimates for cost per hour are based on 2015 wage figures and derived as follows:

- $64.29/hour, the average salary plus benefits per engineer (from Bureau of Labor Statistics at https://www.bls.gov/oes/current/naics2_22.htm);
- $37.75/hour, the average salary plus benefits per information and record clerks (from Bureau of Labor Statistics at https://www.bls.gov/oes/current/naics2_22.htm)

The results of calculations are rounded to the nearest dollar within the burden table.

Updating, Approving, and Maintaining Records	215	1	215	6 hrs. (Eng.); $386 2 hrs. (R.K.); $76	1,290 hrs. (Eng.); $82,934 430 hrs. (R.K.); $16,233	$386 (Eng.); $76 (R.K.)
One-time Contracting	27	1	27	120 hrs. (Eng.) $7,715	3,240 hrs. $208,300 (Eng.)	$7,715 (Eng.)
EOP-005-3 & EOP-006-3						
RC Data Retention	26	2	52	8 hrs. (R.K.) $514	416 hrs. (R.K.); $26,745	$514 (R.K.)
TOP Reporting Data	176	1	176	116 hrs. (Eng.); $7,458 16 hrs. (R.K.); $604	20,416 hrs. (Eng.); $1,312,545 2,816 hrs. (R.K.); $106,304	$7,458 (Eng.); $604 (R.K.)
GOP Testing	230	1	230	80 hrs. (Eng.); $5,143	18,400 hrs. (Eng.); $1,182,936	$5,143 (Eng.)
TO and DP Training	678	1	678	8 hrs. (Eng.); $514	5,424 hrs. (Eng.); $348,709	$514 (Eng.)
EOP-004-4						
One-Time Review and Revision of Plan	1,400	1	1,400	2 hrs. (Eng.); $129	2,800 hrs. (Eng.) $180,012	$129
Reporting Events	350	1	350	0.17 hrs. (Eng.); $11	59.5 hrs. (Eng.); $3,825	$11
TOTAL			3,343		55,929.5 (Eng.) 3,662 (R.K.) $3,595,708 (Eng.) $149,282 (R.K.)	

Title: FERC-725S (Mandatory Reliability Standards).[14]

Action: Proposed Collection of Information.

OMB Control No.: 1902-0270.

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

Frequency of Responses: Annually.

Necessity of the Information: Proposed Reliability Standards EOP-004-4, EOP-005-3, EOP-006-3, and EOP-008-2 are intended to provide accurate reporting of events to NERC's event analysis group to analyze the impact on the reliability of the bulk electric system (EOP-004-4); delineate the roles and responsibilities of entities that support system restoration from blackstart resources (EOP-005-3); clarify the procedures and coordination requirements for reliability coordinator personnel to execute system restoration processes (EOP-006-3); and refine the required elements of an operating plan used to continue reliable operations of the bulk electric system if that primary control functionality is lost (EOP-008-2).

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.

[14] The revisions to EOP-004-4, EOP-005-3, EOP-006-3, and EOP-008-2 Reliability Standards will result in paperwork burden being accounted for in FERC-725S (OMB Control No. 1902-0270). These standards will replace previous versions whose paperwork burden was previously approved in FERC-725A (OMB Control. No. 1902-0244). The burden proposed here will only be added to FERC-725S and will be temporarily duplicated by previously approved burden in FERC-725A.

20. Interested persons may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street, NE Washington, DC 20426 [Attention: Ellen Brown, Office of the Executive Director, e-mail: DataClearance@ferc.gov, phone: (202) 502-8663, fax: (202) 273-0873].

21. For submitting comments concerning the collection(s) of information and the associated burden estimate(s), please send your comments to the Commission and to the Office of Management and Budget, Office of Information and Regulatory Affairs, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission, phone: (202) 395-4638, fax: (202) 395-7285]. For security reasons, comments to OMB should be submitted by e-mail to: oira_submission@omb.eop.gov. Comments submitted to OMB should include 1902-0270 and Docket Number RM17-12-000.

IV. Environmental Analysis

22. 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.[15] 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

[15] *Regulations Implementing the National Environmental Policy Act of 1969*, Order No. 486, FERC Stats. & Regs. ¶ 30,783 (1987).

not substantially change the effect of the regulations being amended.[16] The actions proposed here fall within this categorical exclusion in the Commission's regulations.

V. Regulatory Flexibility Act

23. The Regulatory Flexibility Act of 1980 (RFA)[17] generally requires a description and analysis of proposed rules that will have significant economic impact on a substantial number of small entities. Because the burden discussed above is being accounted for in FERC-725S these standards will replace previous versions whose paperwork burden was previously approved in FERC-725A. The burden will only be added to FERC-725S and will be temporarily duplicated by previously approved burden in FERC-725A. Accordingly, the Commission certifies that the proposed Reliability Standards will not have a significant economic impact on a substantial number of small entities.

VI. Comment Procedures

24. The Commission invites interested persons to submit comments on the matters and issues proposed in this notice to be adopted, including any related matters or alternative proposals that commenters may wish to discuss. Comments are due [**INSERT DATE 60 days after publication in the FEDERAL REGISTER**]. Comments must refer to Docket No. RM17-12-000, and must include the commenter's name, the organization they represent, if applicable, and their address in their comments.

[16] 18 CFR 380.4(a)(2)(ii).

[17] 5 U.S.C. 601-612.

25. The Commission encourages comments to be filed electronically via the eFiling link on the Commission's web site at http://www.ferc.gov. The Commission accepts most standard word processing formats. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format. Commenters filing electronically do not need to make a paper filing.

26. Commenters that are not able to file comments electronically must send an original of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street NE, Washington, DC 20426.

27. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section below. Commenters on this proposal are not required to serve copies of their comments on other commenters.

VII. Document Availability

28. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (http://www.ferc.gov) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington, DC 20426.

29. From the Commission's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and

Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number of this document, excluding the last three digits, in the docket number field.

30. User assistance is available for eLibrary and the Commission's website during normal business hours from the Commission's Online Support at (202) 502-6652 (toll free at 1-866-208-3676) or e-mail at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202) 502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

By direction of the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

20170914-3004 FERC PDF (Unofficial) 09/14/2017

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

OFFICE OF ENERGY MARKET REGULATION

In Reply Refer To:
North American Electric Reliability
Corporation
Docket No. RR17-4-000

September 14, 2017

Schiff Hardin LLP
233 South Wacker Drive, Suite 6600
Chicago, IL 60606

Attention: Owen E. MacBride
Attorney for North American Electric Reliability Corporation

Reference: Report of Comparisons of Budgeted to Actual Costs for 2016

Dear Mr. MacBride:

On May 30, 2017, North American Electric Reliability Corporation (NERC) submitted a report of comparisons of budgeted to actual costs for 2016 for NERC and the Regional Entities.

Notice of this filing was issued on May 30, 2017, with protests and interventions due on or before June 20, 2017. Notices of intervention and unopposed timely filed motions to intervene are granted pursuant to the operation of Rule 214 of the Commission's Rules of Practice and Procedure. 18 C.F.R. § 385.214. No protest was filed.

NERC's uncontested filing is accepted pursuant to the relevant authority delegated to the Director, Office of Energy Market Regulation, under 18 C.F.R. § 375.307.

This action shall not be construed as approving any other application, including proposed revisions of Electric Reliability Organization or Regional Entity rules or procedures pursuant to 18 C.F.R. § 375.307(a)(2)(vi). This action does not constitute approval of any service, rate, charge, classification, or any rule, regulation, contract, or practice affecting such rate or service provided for in the filed documents. Such action shall not be deemed as recognition of any claimed right or obligation associated therewith and such action is without prejudice to any findings or orders that have been or may

20170914-3004 FERC PDF (Unofficial) 09/14/2017

hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against the Electric Reliability Organization or any Regional Entity.

This order constitutes final agency action. Requests for rehearing by the Commission may be filed within 30 days of the date of issuance of this order pursuant to 18 C.F.R. § 385.713.

Sincerely,

Penny S. Murrell, Director
Division of Electric Power Regulation – Central

Document Content(s)

RR17-4-000.DOCX.....1-2

20171002-3039 FERC PDF (Unofficial) 10/02/2017

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Grid Reliability and Resilience Pricing Docket No. RM18-1-000

NOTICE INVITING COMMENTS

(October 2, 2017)

On September 28, 2017, pursuant to section 403 of the Department of Energy Organization Act,[1] the Secretary of Energy (Secretary) released a proposed rule for final action (Proposal) by the Federal Energy Regulatory Commission (Commission).[2]

Interested persons are invited to submit comments regarding the Proposal. Comments are due on or before October 23, 2017. Reply comments are due on or before November 7, 2017.

Comments must refer to Docket No. RM18-1-000 and must include the commenter's name, the organization they represent, if applicable, and their address.

The Commission encourages comments to be filed electronically via the eFiling link on the Commission's web site at http://www.ferc.gov. The Commission accepts most standard word processing formats. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format. Commenters filing electronically do not need to make a paper filing.

Commenters that are not able to file comments electronically must send an original of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE, Washington, DC 20426.

[1] 42 U.S.C. § 7173 (2012).

[2] The full text of the Proposal can be found at: https://energy.gov/downloads/notice-proposed-rulemaking-grid-resiliency-pricing-rule.

20171002-3039 FERC PDF (Unofficial) 10/02/2017

All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely. Commenters on the Proposal are not required to serve copies of their comments on other commenters.

Kimberly D. Bose,
Secretary.

Document Content(s)

RM18-1-000.DOCX.....1-2

NEWS RELEASE

September 12, 2017
News Media Contact
Craig Cano | 202-502-8680

FERC Announces 2018 Open Meeting Schedule

Federal Energy Regulatory Commission Chairman Neil Chatterjee today announced the schedule for the Commission's open meetings for calendar year 2018.

Meetings take place on the third Thursday of every month. FERC does not meet in August.

The open meeting dates for calendar year 2018 are as follows:

January 18
February 15
March 15
April 19
May 17
June 21
July 19
September 20
October 18
November 15
December 20

The meetings, at FERC's headquarters at 888 First Street NE, in Washington, D.C., are open to the public consistent with the Government in the Sunshine Act.

R-17-31

(30)

September 2017
Commission Meeting Summaries

These are the summaries of orders voted by the Federal Energy Regulatory Commission at its September 20, 2017 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, E-2, & E-3 – Press Release

FERC accepts proposed tariff revisions

E-4, *Arizona Public Service Company*, Docket Nos. ER16-2656-000, -001, -002, & -003. This order accepts APS' revisions to its Open Access Transmission Tariff, finding that APS' revisions clarify the processes for customers requesting an umbrella service agreement and provide further illustration of rates associated with operating reserve service. The order also finds that APS' request for clarification and/or rehearing is moot.

FERC authorizes negotiated rate proposal

E-5, *SunZia Transmission, LLC*, Docket No. ER17-388-000. This order authorizes SunZia to charge negotiated rates for transmission rights on Phase 1 of a proposed high-voltage alternating current merchant transmission project, and accepts SunZia's open solicitation and selection report.

FERC authorizes allocation of costs of non-power goods and services

E-6, *AES US Services, LLC*, Docket No. ER16-1564-000. This order grants AES' request for authorization of the allocation of costs of non-power goods and services to Indianapolis Power & Light Company in accordance with section 1275 of the Energy Policy Act of 2005 and certain other regulations. AES submitted this request at the direction of the Indiana Utility Regulatory Commission as part of a state rate proceeding.

FERC accepts filing

E-7, *Exelon Generation Company, LLC*, Docket No. ER17-933-000. The order grants Exelon Generation's request for recovery of fuel costs for Units 8 and 9 of the Mystic Generating Station, which were not recovered due to market power mitigation applied during the months of October and November 2016, as well as associated regulatory costs. The order also grants waiver of ISO New England Inc.'s Tariff permitting Exelon Generation to make its request for cost recovery beyond the 60-day period otherwise required by ISO-NE's Transmission, Markets, and Services Tariff.

FERC accepts a compliance filing

E-8, *Louisiana Public Service Commission and the Council of the City of New Orleans v. Entergy Corporation*, Docket No. EL00-66-021. In this order, the Commission accepts Entergy's compliance filing, finding that the filing satisfies the directives in the Commission's order issued earlier in this proceeding that conditionally approved an offer of settlement.

FERC denies a Formal Challenge

E-9, *Delmarva Power & Light Company*, Docket No. ER09-1158-000. This order denies a Formal Challenge filed by the Delaware Municipal Electric Corporation, Inc. challenging certain inputs to Delmarva Power & Light Company's 2016 formula rate annual update.

FERC grants waiver

E-10, *Basin Electric Power Cooperative*, Docket No. EL17-46-000. The order grants a petition for partial waiver of Basin's obligation under FERC regulations to make retail sales to qualifying facilities (with its Participating Members assuming that obligation), and of its Participating Members' obligation to make purchases from qualifying facilities with a nameplate capacity of 150 kilowatts or more (with Basin assuming that obligation).

FERC rejects proposed tariff revisions

E-11, *Midcontinent Independent System Operator, Inc.*, Docket No. ER17-387-001. The order rejects MISO's proposed revisions to Attachment FF-6 of its Open Access Transmission, Energy and Operating Markets Tariff that would provide a cost allocation method for interregional transmission projects terminating wholly outside MISO.

FERC accepts proposed tariff revisions

E-12, *Midcontinent Independent System Operator, Inc*., Docket No. ER17-1302-000. This order accepts MISO's proposed revisions to Attachment LL of its Open Access Transmission, Energy and Operating Reserve Markets Tariff. The proposed revisions modify MISO's existing processes with its seams and coordinating partners to include flows resulting from bi-directional External Asynchronous Resources in the MISO market flow calculation under the Congestion Management Process.

FERC accepts proposed tariff revisions

E-13, *Midcontinent Independent System Operator, Inc*., Docket No. ER17-1303-000. The order accepts MISO's proposed revisions to Rate Schedule 8 (Seams Operating Agreement between MISO and Manitoba Hydro) of its Open Access Transmission, Energy and Operating Reserve Markets Tariff. The proposed revisions modify MISO's existing processes with its seams and coordinating partners to include flows resulting from bi-directional External Asynchronous Resources in the MISO market flow calculation under the baseline Congestion Management Process.

FERC accepts proposed tariff revisions

E-14, *Midcontinent Independent System Operator, Inc*., Docket No. ER17-1304-000. The order accepts MISO's proposed revisions to Rate Schedule 46 (Coordination and Operating Agreement between the MISO and Minnkota Power Cooperative, Inc.) of its Open Access Transmission, Energy and Operating Reserve Markets Tariff. The proposed revisions modify MISO's existing processes with its seams and coordinating partners to include flows resulting from bi-directional External Asynchronous Resources in the MISO market flow calculation under the baseline Congestion Management Process.

FERC accepts proposed tariff revisions

E-15, *Midcontinent Independent System Operator, Inc*., Docket No. ER17-1305-000. This order accepts MISO's proposed revisions to Rate Schedule 5 (Joint Operating Agreement between the MISO and PJM Interconnection, L.L.C.) of its Open Access Transmission, Energy and Operating Reserve Markets Tariff. The proposed revisions modify MISO's existing processes with its seams and coordinating partners to include flows resulting from bi-directional External Asynchronous Resources in the MISO market flow calculation under the Congestion Management Process, as well as specify other information sharing obligations, and align the Day-Ahead Energy Market Coordination and the Auction Revenue Rights Allocation/Financial Transmission Rights Coordination with Market-to-Market settlement practice.

FERC accepts proposed tariff revisions

E-16, *Midcontinent Independent System Operator, Inc*., Docket No. ER17-1332-000. This order accepts MISO's proposed revisions to Rate Schedule 6 (Joint Operating Agreement between the MISO and Southwest Power Pool, Inc.) of its Open Access Transmission, Energy and Operating Reserve Markets Tariff. The proposed revisions modify MISO's existing processes with its seams and coordinating partners to include flows resulting from bi-directional External Asynchronous Resources in the MISO market flow calculation under the Congestion Management Process, as well as specify other information sharing obligations.

FERC accepts proposed revisions

E-17, *PJM Interconnection, L.L.C.*, Docket No. ER17-1306-000. This order accepts revisions to PJM's Joint Operating Agreement with the Midcontinent Independent System Operator, Inc. to include flows resulting from bi-directional External Asynchronous Resources in the MISO market flow calculation, to specify other information-sharing obligations, and to align forward market congestion management with Market-to-Market settlement practice.

FERC accepts proposed revisions

E-19, *Southwest Power Pool, Inc.*, Docket No. ER17-1333-000. This order accepts SPP's proposed revisions to its Joint Operating Agreement with the Midcontinent Independent System Operator, Inc. to modify its existing processes with its seams and coordinating partners to include flows resulting from bi-directional External Asynchronous Resources and to specify other information sharing obligations.

FERC accepts proposed tariff revisions

E-20, *Southwest Power Pool, Inc*., Docket No. ER17-520-000. This order accepts SPP's proposed revisions to Attachment AE of its Open Access Transmission Tariff. The revisions specify that all resources that are dispatched to zero by SPP will be exempt from the real-time outage reliability unit commitment make whole payment deviation charge.

FERC accepts proposed tariff revisions, subject to a further compliance filing

E-21, *Southwest Power Pool, Inc*., Docket Nos. ER17-772-000, *et al*. This order accepts, subject to a further compliance filing, SPP's revisions to its Open Access Transmission Tariff to comply with the requirements of Order No. 825. In Order No. 825, the Commission required that each regional transmission organization (RTO) and independent system operator (ISO) align settlement and dispatch intervals by: (1) settling energy transactions in its real-time markets at the same time interval it dispatches energy;

(2) settling operating reserves transactions in its real-time markets at the same time interval it prices operating reserves; and (3) settling intertie transactions in the same time interval it schedules intertie transactions. The Commission also required that each RTO/ISO establish a mechanism to trigger shortage pricing for any interval in which a shortage of energy or operating reserves is indicated during the pricing of resources for that interval.

FERC grants request for declaratory order

E-22, *Alcoa Corporation*, Docket No. EL17-34-000. This order grants Alcoa's request for a declaratory order exempting Alcoa from certain of the books and accounts regulations under the Public Utility Holding Company Act of 2005 pursuant to the exemption provision of section 366.3(b)(1) of the Commission's regulations.

FERC denies request for rehearing

E-23, *Pacific Gas and Electric Company*, Docket No. ER16-2320-001. This order denies requests for rehearing of the Commission's September 30, 2016 order in this proceeding, which accepted for filing PG&E's tariff revisions to implement a rate increase under its Transmission Owner Tariff, suspended the revisions for five months to be effective on March 1, 2017, subject to refund, and established hearing and settlement judge procedures. The order reaffirms the Commission's granting a 50 basis-point incentive return-on-equity adder to utilities that join or remain members of ISO/RTOs.

FERC grants an extension

G-2, *Black Marlin Pipeline*, Docket No. RP17-349-000. This order grants Black Marlin's request for an extension of its two-year exemption from certain of its tariff provisions, including the North American Energy Standards Board nominations-related standards in its tariff.

FERC approves an uncontested settlement

G-3, *Texas Eastern Transmission, LP*, Docket No. RP17-519-000. This order approves an uncontested settlement between Texas Eastern and its shippers resolving issues related to payment of the true-up amount of Texas Eastern's incurred, but unrecovered, eligible polychlorinated biphenyl-related cleanup costs through March 31, 2017, plus applicable interest.

FERC grants a temporary waiver of oil pipeline tariff filings and reporting requirements

G-4, *Western Refining Pipeline, LLC,* Docket No. OR13-14-002. This letter order grants Western's December 16, 2016 request for temporary waiver of tariff filing and reporting requirements under sections 6 and 20 of the Interstate Commerce Act (ICA) and of parts 341 and 357 of the Commission's regulations that implement sections 6 and 20 of the ICA. The order confirms that the waiver continues to apply to 10-inch feeder lines as previously granted in the February 27, 2013 Original Waiver Order; continues to apply to earlier added facilities as granted in the June 4, 2015 Amended Waiver Order; and that the waiver now extends to certain New Lines as sought by Western in its December 16, 2016 request.

FERC grants stay, denies motion to intervene

H-1, *Public Utility District No. 1 of Okanogan County, Washington,* Project No. 12569-014. This order grants Okanogan PUD's request for a two-year stay of the commencement and completion of construction deadlines for the 9-megawatt Enloe Hydroelectric Project No. 12569, to be located on the Similkameen River near the City of Oroville in Okanogan County, Washington. The order finds that Okanogan PUD has demonstrated that, for reasons beyond its control, it was not able to timely commence project construction. The order also denies a motion to intervene because the proceeding is a post-licensing proceeding of the type where the Commission does not issue a public notice or provide an opportunity to intervene.

FERC grants request for rehearing

H-2, *City of Nashua, Iowa,* Project No. 12628-013. This order grants the City of Nashua's request for rehearing of Commission's staff's order denying the City's request to amend its Operations Compliance Monitoring Plan and Water Quality Monitoring Plan for the Cedar Lake Hydroelectric Project No. 12628, located on the Cedar River in Chickasaw County, Iowa. Based on the additional information filed with the City's rehearing request, the order finds that the City has provided operational information and water quality data to demonstrate that the project does not adversely affect dissolved oxygen concentrations. The order finds that additional monitoring is not necessary at this time and approves the City's amendment request.

FERC denies requests for rehearing

H-3, *Public Utility District No. 2 of Grant County, Washington,* Project No. 2114-289 This order denies a rehearing request filed by Sunland Estates Homeowners Association (Sunland HOA) of the Commission's January 19, 2017 order amending the project boundary for the Priest Rapids Project, located on the mid-Columbia River in portions of Grant, Yakima, Kittitas, Douglas, Benton, and Chelan counties, Washington. The order rejects Sunland HOA's arguments that (1) the January 2017 Order erroneously stated that

the Federal Power Act preempts local covenants that purport to restrict the licensee's ability to carry out project purposes; and (2) the parcel of land placed within the boundary is not actually needed for project purposes. Also, the order denies Pat Kelleher's rehearing request, finding Mr. Kelleher's arguments to be both beyond the scope of these proceedings and, in any event, lacking merit.

FERC dismisses requests for rehearing

H-4, *Alcoa Power Generating Inc. and Cube Yadkin Generation LLC*, Project Nos. 2197-112 and 2197-113. This order dismisses three rehearing requests related to Commission staff's approval of the transfer of the license for the Yadkin Hydroelectric Project, located on the Yadkin River in Stanly, Montgomery, Davidson, and Rowan counties, North Carolina, from Alcoa Power Generating, Inc. to Cube Yadkin Generation LLC. The rehearing requests fail to list a statement of issues as required by 18 C.F.R. 385.713(c)(2). In the alternative, the order denies two of the rehearing requests and rejects the third.

FERC denies requests for rehearing

H-5, *Alcoa Power Generating Inc. and Cube Yadkin Generation LLC*, Project No. 2197-110. This order responds to three rehearing requests regarding Commission staff's September 22, 2016 order issuing a new license for the continued operation and maintenance of the Yadkin Hydroelectric Project No. 2197. The order rejects New Energy Capital Partners, LLC's request for rehearing and denies its request to stay the license because New Energy is not a party to the proceeding. The order denies the rehearing requests filed by City of Salisbury, North Carolina, and the State of North Carolina. Last, the order denies the stay request filed by the State of North Carolina.

FERC denies requests for rehearing

H-6, *Public Utility District No. 2 of Grant County, Washington*, Project Nos. 2114-286 and 2114-287. This order denies rehearing requests filed by Pat Kelleher and Danna Dal Porto in response to two orders involving Crescent Bar Island, located within the Priest Rapids Project boundary on the mid-Columbia River in portions of Grant, Yakima, Kittitas, Douglas, Benton, and Chelan Counties, Washington. In the first order, issued on September 21, 2016, Commission staff approved a Recreation Resources Management Plan amendment, authorizing the licensee, Public Utility District No. 2 of Grant County, Washington, to amend its recreation plan and add certain recreation improvements within the Crescent Bar Recreation Area. In the second order, issued on November 17, 2016, the Commission authorized certain project and non-project uses of project lands on Crescent Bar Island.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Lesson Learned

Auxiliary Power Loss to STATCOM Leads to UVLS Operation

Primary Interest Groups
Transmission Operators (TOPs)
Transmission Owners (TOs)
Reliability Coordinators (RCs)

Problem Statement
A voltage disturbance on the transmission system led to the loss of redundant auxiliary cooling system power sources for a static synchronous compensator (STATCOM), causing the STATCOM to trip. Both auxiliary cooling power supplies were fed from the same high-voltage substation. The loss of the STATCOM exacerbated a low-voltage condition on the transmission system. Undervoltage load shed (UVLS) relays on distribution feeders in the area tripped as a result of the low voltage, shedding 92 MW of firm load.

Details
A STATCOM's auxiliary power is critical to operating its cooling system, which has two pump motors that circulate coolant through the power electronics. During normal operation, one cooling pump runs and the other remains on standby. If the power to the circulating pump is disturbed, a transfer switch will operate to switch to the backup feed and pump.

A post insulator for a 138 kV transmission line failed, causing the line to fall across the 138 kV bus at the substation. Protection system misoperations resulted in the loss of two additional 138 kV transmission lines. A STATCOM, rated at +/- 150 MVAR, was connected to a substation approximately 22 miles from the faulted substation bus.

In this event, both of the auxiliary power supplies to the STATCOM's transfer switch were fed from the same transmission source. When the disturbance affected both feeds, the transfer switch did not have a good source to transfer to. This caused the transfer to fail and the cooling system to trip off. As a result, the STATCOM tripped off to protect the power electronics from the loss of cooling. Relay data available for the event shows voltage on the transmission bus that the STATCOM was connected to lowered to 0.7 per unit.

The trip of the STATCOM exacerbated the low-voltage condition in the area, causing the loss of an additional 57 MVAR capacitor bank. Undervoltage load shed relays on distribution feeders in the area, set at 0.85 per unit with a two second time delay, responded to the low voltage and tripped 92 MW of firm load.

Corrective Actions
An uninterruptible power supply (UPS) was installed to supply the STATCOM auxiliary equipment.

Lesson Learned

Design philosophy for a device that protects BPS voltage should ensure that a voltage disturbance cannot prevent the device from functioning as intended.

The auxiliary power system is critical to the proper operation of STATCOM equipment. Proper system design should ensure that auxiliary power sources are redundant and fed from sources that are electrically separated from areas that need STATCOM voltage support. If that is not feasible, a UPS should be considered.

Click here for: Lesson Learned Comment Form

For more Information please contact:

NERC – Lessons Learned (via email)	Texas Reliability Entity (via email)
Source of Lesson Learned:	Texas Reliability Entity
Lesson Learned #:	20170801
Date Published:	August 24, 2017
Category:	Transmission Facilities

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

ERO Enterprise Combined 2018 Budgets and Assessments

Scott Jones, Vice President of Finance
Finance and Audit Committee Meeting
August 9, 2017

RELIABILITY | ACCOUNTABILITY

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2017 vs 2018 Budgeted Expenses ($000's)

Entity	2017	% of Total ERO Budget	2018	% of Total ERO Budget	% Change
NERC	$ 69,602	36.3%	$ 73,135	37.0%	**5.1%**
FRCC	7,178	3.7%	7,514	3.8%	**4.7%**
MRO	11,227	5.9%	11,727	5.9%	**4.5%**
NPCC	15,147	7.9%	15,107	7.6%	**-0.3%**
RF	19,909	10.4%	21,394	10.8%	**7.5%**
SERC	17,482	9.1%	17,183	8.7%	**-1.7%**
SPP RE	10,866	5.7%	10,793	5.5%	**-0.7%**
TRE	12,167	6.4%	12,657	6.4%	**4.0%**
WECC	26,797	14.0%	27,097	13.7%	**1.1%**
WIRAB	1,229	0.6%	1,068	0.5%	**-13.1%**
	$ 191,604	**100.0%**	**$ 197,675**	**100.0%**	**3.2%**

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2017 vs 2018 Average Assessments
($000's)

Entity	2017	2018	Change 2018 v 2017	% Change
NERC	$ 59,856	$ 62,937	$ 3,081	**5.1%**
FRCC	6,164	6,661	497	**8.1%**
MRO	10,494	10,730	236	**2.2%**
NPCC	14,255	14,342	87	**0.6%**
RF	19,561	20,148	587	**3.0%**
SERC	15,706	17,205	1,499	**9.5%**
SPP	9,093	9,727	635	**7.0%**
TRE	9,595	11,272	1,677	**17.5%**
WECC	25,282	25,282	0	**0.0%**
WIRAB	901	711	-190	**-21.1%**
TOTAL ERO ENTERPRISE	**$ 170,908**	**$ 179,014**	**$ 8,106**	**4.7%**

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Change in Total ERO Enterprise Assessments (by Region)

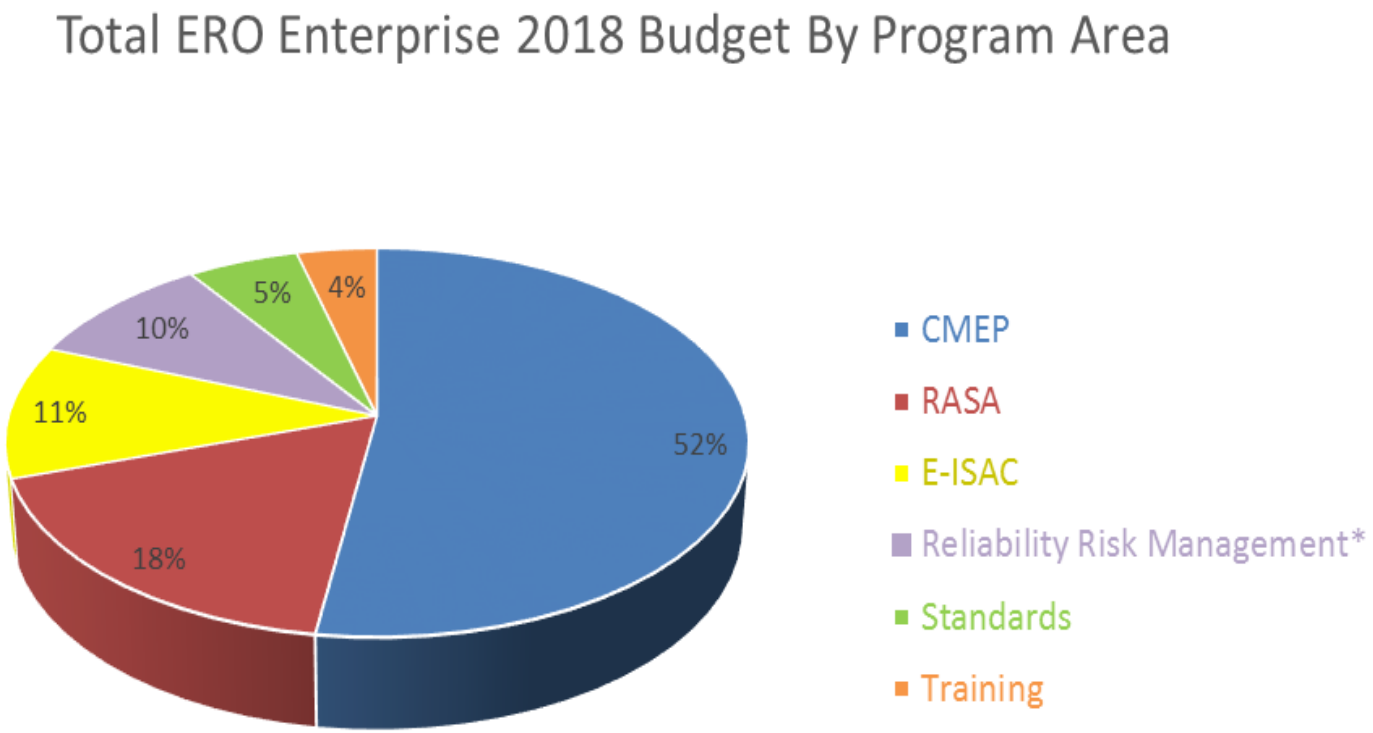
REGION	% Change 2016 v 2015	% Change 2017 v 2016	% Change 2018 v 2017
FRCC	7.6%	-2.0%	6.9%
MRO	11.8%	-2.1%	3.6%
NPCC	1.3%	1.0%	2.6%
RF	3.3%	1.8%	3.9%
SERC	2.1%	10.0%	7.3%
SPP RE	-6.5%	4.5%	6.7%
TRE	-4.6%	2.5%	13.8%
WECC	1.1%	1.4%	0.6%
Total $ Change	**$ 2,977,758**	**$ 4,399,595**	**$ 8,106,719**
Total % Change	**1.8%**	**2.6%**	**4.7%**

Note: NERC assessments are allocated to each Regional Entity using NEL data. For purposes of this table, NERC assessments were allocated using the 2016 data.

Factors Impacting Change in Assessments By Entity

- NERC and Regional Entity resource requirements and budgets
- Year-End reserve levels
  - Surplus reserves
  - Reserves from prior years that can be applied
- Penalty funds and stabilization reserves (U.S. only)
  - Loss of one time offsets applied in prior year
  - New penalty funds available
- Year to year NEL (Net Energy for Load) variations
- Application and true-up of certain Canadian credits

Combined Budget by Program Area



*For NERC Includes Performance Analysis, Event Analysis and Situation Awareness
For Regions includes Situation Awareness

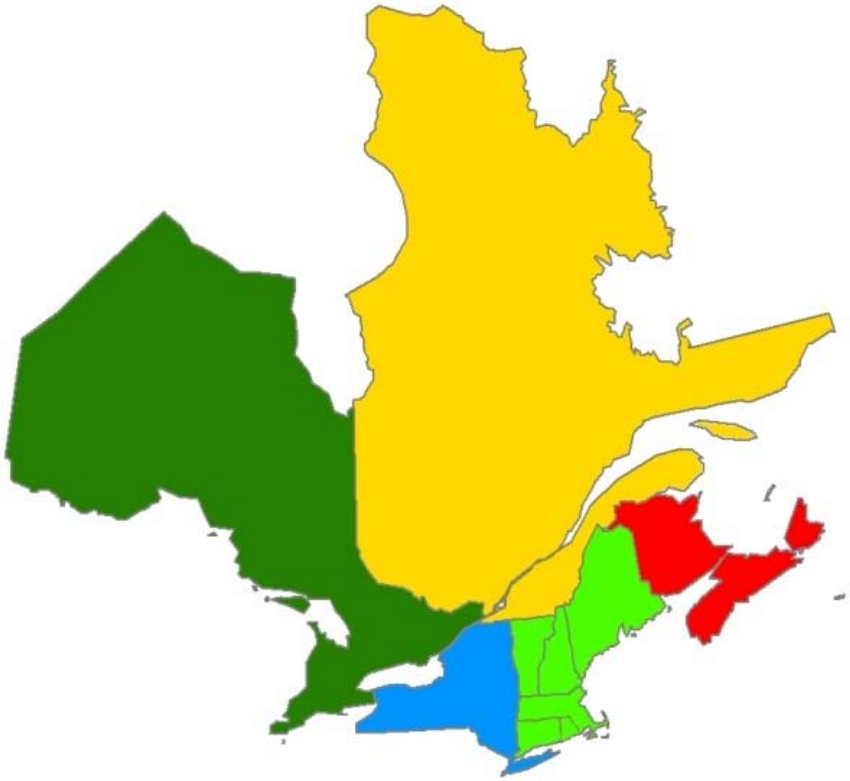
ERO Enterprise Resource Allocation

Questions and Answers

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

Northeast Power Coordinating Council, Inc. (NPCC)

2018 Business Plan and Budget



Draft 1
Submitted to NERC May 5, 2017

Table of Contents

Introduction 3
Personnel Analysis 12
Section A — 2018 Regional Entity Division Business Plan and Budget 15
Reliability Standards Program 15
Compliance Monitoring and Enforcement and Organization Registration and Certification Program 22
Reliability Assessment and Performance Analysis Program 30
Training, Education, and Operator Certification Program 42
Situation Awareness and Infrastructure Security Program 46
Administrative Services 53
Technical Committees and Member Forums 55
General and Administrative 56
Legal and Regulatory 57
Information Technology 58
Human Resources 60
Accounting and Finance 61
Regional Entity Assessment Analysis 62
Section B — Supplemental Financial Information 66
Regional Entity Reserve Analysis 2017 - 2018 66
Breakdown by Statement of Activity Sections 67
Section C —2018 Criteria Services Division Business Plan and Budget 75
Personnel Analysis 82
Criteria Services Reserve Analysis 2017 - 2018 83
Section D — Additional Financial Statements 85
Statement of Financial Position 85
Appendix A Staff Allocations 88
Appendix B Acronyms 90
Appendix C Index of Figures and Tables 92

Introduction

Total NPCC Resources (in whole dollars)	2018 Budget	U.S.	Canada	Mexico
Regional Entity Division FTEs	36.86			
Criteria Services Division FTEs	2.14			
Total FTEs	**39.0**			
Regional Entity Division Expenses	$15,260,967			
Criteria Services Division Expenses	$1,082,983			
Total Expenses	**$16,343,950**			
Regional Entity Division Inc(Dec) in Fixed Assets	**($154,000)**			
Criteria Services Division Inc(Dec) in Fixed Assets	**($16,000)**			
Total Inc(Dec) in Fixed Assets	**($170,000)**			
Regional Entity Division Working Capital Requirement**	**($626,180)**			
Criteria Services Division Working Capital Requirement***	**($47,843)**			
Total Working Capital Requirement	**($674,023)**			
Total Regional Entity Division Funding Requirement	$14,480,787			
Total Criteria Services Division Funding Requirement	$1,019,141			
Total Funding Requirement	**$15,499,927**			
Regional Entity Division Assessments	**$14,341,787**	$XXX,XXX	$XXX,XXX	
Regional Entity Division Assessments Percentage	**100.0%**	XX.X%	XX.X%	
Criteria Services Division Membership Fees	**$1,019,141**	$XXX,XXX	$XXX,XXX	
Total NPCC Assessments & Membership Fees	**$15,360,927**	$XXX,XXX	$XXX,XXX	
NEL	XX	XX	XX	
NEL %	100%	XX.XX%	XX.XX%	

** Refer to Table B-1 on page 66 in Section B.
*** Refer to the Reserve Analysis on page 83 in Section C.

2018 Overview of Total NPCC Resource Requirements

Due to the international nature of NPCC, the total resource requirements including both Regional Entity division and Criteria Services division are identified above. The individual divisional explanations are contained in subsequent sections.

NPCC proposes no change to its total budget and assessments. On a division level, NPCC proposes a Regional Entity total budget decrease of 0.3% and a Criteria Services division total budget increase of 3.8%. The proposed 2018 funding requirements will be satisfied by a Regional Entity division assessment of $14,341,787 and Criteria Services division fees of $1,019,141, for a total of $15,360,927. The total NPCC assessments and fees of $15,360,927 represents no change from 2017. NPCC believes that the Region remains an effective provider of Regional Entity and Criteria Services division functions. NPCC's corporate culture centers on consistent delivery of excellent results at a cost that is considerate of the longstanding tradition in the Northeast of affordable and reliable electricity.

Organizational Overview

Northeast Power Coordinating Council, Inc. (NPCC) is a 501(c)(6) not-for-profit corporation in the state of New York responsible for promoting and improving the reliability of the international, interconnected bulk power systems in Northeastern North America through (i) the development of Regional Reliability Standards and compliance assessment and enforcement of continent-wide and Regional Reliability Standards, coordination of system planning, design and

operations, and assessment of reliability (collectively, Regional Entity activities), and (ii) the establishment of Regionally-specific criteria, and monitoring and enforcement of compliance with such criteria (collectively, criteria services activities). NPCC provides the functions and services for Northeastern North America of a cross-border Regional Entity through a Regional Entity division, as well as Regionally-specific criteria services for Northeastern North America through a criteria services division. NPCC's website is www.npcc.org.

The NPCC Region covers nearly 1.2 million square miles and is populated by more than 56 million people. NPCC U.S. includes the six New England states and the state of New York. NPCC Canada includes the provinces of Ontario, Québec and the Maritime provinces of New Brunswick and Nova Scotia. In total, from a net energy for load perspective, NPCC is approximately 45% U.S. and 55% Canadian. With regard to Canada, approximately 70% of Canadian net energy for load is within the NPCC Region.

Effective January 1, 2016, NPCC executed an Amended and Restated Regional Delegation Agreement with the North American Electric Reliability Corporation (NERC) that delegates to NPCC certain responsibilities and authorities of a cross-border Regional Entity as defined by *Section 215* of the Federal Power Act in the U.S. In addition, NPCC has executed Memoranda of Understanding or Agreements with Canadian provincial regulatory and/or governmental authorities in Ontario, Québec, New Brunswick and Nova Scotia.

It is imperative that NPCC maintain its ability to carry out delegated authorities and responsibilities. NPCC has a flat 2018 targeted staffing level of 39 power industry professionals and support personnel. Details of the 2018 business plans and budget for each program area are included in Section A for the Regional Entity division. The 2018 Regional Entity division schedules are shown in Section B. Section C details the 2018 criteria services division business plan and budget.

Membership and Governance

NPCC monitors approximately 205 registered entities and some 427 functions in the Region for compliance with mandatory Reliability Standards. NPCC currently has approximately 80 members. There are two categories of membership, General and Full. The two categories distinguish between Regional Entity delegated services that are provided in support of the U.S. FERC and Canadian provincial MOUs or Agreements with regulatory and/or governmental authorities, and Criteria Services which FERC references as U.S. non-delegated activities.

General Membership is voluntary and is open to any person or entity, including any entity participating in the Registered Ballot Body of the Electric Reliability Organization (ERO) that has an interest in the reliable operation of the Northeastern North American bulk power system. General Members which are also registered entities within the NPCC Region are subject to compliance with Reliability Standards, consistent with their registration, and also receive additional services from the Regional Entity division of NPCC.

Full Membership is available to Members which are already General Members and participate in electricity markets in the Northeast. Independent system operators (ISOs), Regional transmission organizations (RTOs), Transcos and other organizations or entities that perform the Balancing Authority function operating in Northeastern North America are expected to be Full Members of NPCC. The New York State Reliability Council and any other sub-regional reliability councils which may be formed are also expected to be Full Members. Full Members

are subject to compliance with Regionally-specific more stringent reliability criteria for their generation and transmission facilities on which faults or disturbances can have a significant adverse impact outside of the local area and which are identified utilizing a reliability impact-based methodology, in addition to Reliability Standards, and receive additional services from the Criteria Services division of NPCC, which is not funded through the ERO.

Since January 1, 2012 NPCC is governed by a Board of Directors consisting of seven stakeholder voting sectors consisting of a maximum of two directors per sector, an independent sector consisting of two independent directors, an independent Board Chair with voting rights to preclude board deadlocks, and the President and CEO. Within NPCC, no two sectors can control and no one sector can block action. The voting sectors on the NPCC Board of Directors include:

Sector 1) Transmission Owners
Sector 2) Reliability Coordinators
Sector 3) Transmission Dependent Utilities, Distribution Companies, Load Serving Entities
Sector 4) Generator Owners
Sector 5) Marketers, Brokers and Aggregators
Sector 6) Regulators
Sector 7) Sub-Regional Reliability Councils, Customers, other Regional Entities and Interested Entities
Sector 8) Independent

A Finance and Audit Committee (FAC), a Pension Committee (PC), a Corporate Governance and Nominating Committee (CGNC), and a Management Development and Compensation Committee (MDCC) advise the Board on finance, governance, compensation and human resource matters consistent with their approved charters. The Board endorses a non-employee, Certified Public Accountant for election by the NPCC Members as Treasurer of the corporation. The Treasurer chairs the FAC and works with the Chief Operating Officer who provides oversight of the finances of the corporation. The Treasurer reports to the Board on the corporation's financial position, on FAC activities, on tax code requirements, and on independent annual audit results and accounting practices.

The Regional Standards Committee (RSC), the Compliance Committee (CC), the Reliability Coordinating Committee (RCC), and the Public Information Committee, consistent with their approved scopes, are responsible for various reliability issues. The RSC, CC and RCC also provide technical policy recommendations to the Board. All General and Full Members are eligible for representation on the technical committees.

Industry technical experts from within the membership provide valuable input to the Board through various working groups and task forces as well as the committees. The *Amended and Restated Bylaws* establish NPCC's independence from users, owners and operators of the bulk power system through the enhanced governance structure while providing fair stakeholder representation in the election of the Board of Directors and officers. The members, from each of the seven stakeholder voting sectors, vote to elect directors in their respective sector. The *Amended and Restated Bylaws* establish criteria for board service for both stakeholder and independent directors. Independent Directors are drawn from diverse backgrounds and possess a broad range of industry expertise, perspectives, experiences, skill sets and knowledge to contribute to the effective functioning of a hybrid board structure.

Compliance and enforcement activities are carried out by the NPCC compliance staff and are independent of all users, owners and operators of the international bulk electric system. Compliance activities are governed in the United States by the *Amended and Restated Regional Delegation Agreement* between NERC and NPCC, delegating portions of NERC's authority as the ERO to NPCC. NPCC compliance activities in Canada are governed by individual provincial Memorandum of Understanding (MOU) or Agreements with each province providing the unique parameters for compliance and enforcement activities for each of the provinces. An MOU between the Independent Electricity System Operator in Ontario (IESO), NERC and NPCC establishes roles and responsibilities with regard to that province. NPCC, NERC and the New Brunswick Energy and Utilities Board are parties to a MOU that sets forth reliability activities for New Brunswick. The Régie de l'énergie, NERC and NPCC executed an Agreement regarding the implementation of the Québec reliability standards compliance monitoring and enforcement program. NPCC, NERC and Nova Scotia executed a MOU that sets forth the mutual understanding of the parties in relation to the approval and implementation of NERC Reliability Standards and NPCC Regional reliability criteria for the province of Nova Scotia.

International Foundation

The Regional Entity functions and services differ according to particular regulatory backstop:

a) U.S. Foundation

The Federal Energy Regulatory Commission (FERC) certified NERC as the Electric Reliability Organization (ERO) on July 20, 2006. The ERO is responsible for developing and enforcing reliability standards within the United States. In executing part of its responsibilities, NERC delegates authority to the Regional Entities to perform certain functions through delegation agreements. Ensuring the reliability of the bulk power system in the State of New York and the six New England States was delegated from NERC to NPCC through the Amended and Restated Regional Delegation Agreement.

b) Ontario

On February 5, 2010, NERC, NPCC and the IESO amended and restated their earlier MOU, dated November 29, 2006, setting forth their mutual understanding as regards NERC's and NPCC's status in Ontario with respect to standard and criteria development, compliance enforcement, and other related matters. The IESO, whose statutory responsibilities include making and enforcing reliability standards, and making and enforcing Ontario market rules that govern the IESO-controlled grid and the wholesale electricity market, was established April 1, 1999 as the Independent Electricity Market Operator in Ontario under the *Electricity Act, 1998* (Ontario). The IESO is subject to the regulatory oversight of the Ontario Energy Board (OEB).

Among other things, the MOU recognizes that NERC and NPCC are standards authorities under the *Electricity Act, 1998* (Ontario). Additionally, under the authority of that same legislation, and as memorialized in the MOU, the NERC reliability standards and NPCC reliability criteria have effect in Ontario. However, a 2008 amendment to the Electricity Act, 1998 (Ontario) allows the OEB to review these standards and criteria and issue orders preventing their implementation and remanding them back to NERC and NPCC.

The IESO is subject to compliance monitoring and enforcement by NPCC. The IESO is also subject to compliance monitoring and enforcement of the Ontario market rules by the IESO's Market Assessment and Compliance Division (MACD) that operates at arm's length from the IESO's business units. The MOU notes that where MACD, NERC, and NPCC engage in investigations pursuant to their respective mandates regarding compliance, MACD can request to

take the lead. Moreover, of the three, MACD is the only entity that can assess financial penalties for any Ontario market participant's or the IESO's non-compliance with Ontario market rules, which includes non-compliance with NERC standards and NPCC criteria.

The MOU provides for a peer review process to promote the common compliance and enforcement objectives of NERC/NPCC and MACD. From the perspective of NPCC and NERC, this process, in part, is meant to assure registered entities outside of Ontario that the MACD program is rigorous, thorough and reliable.

The IESO is subject to NPCC assessments of compliance, including audits, as well as NPCC remedial action directives to correct non-compliance. In the event that the IESO disagrees with NPCC's finding of a violation or associated assessment of sanctions in connection with standards and criteria, the IESO has a right to a compliance hearing with NPCC.

c) Québec

The Régie de l'énergie, NERC and NPCC are parties to the May 8, 2009 *Agreement on the Development of Electric Power Transmission Reliability Standards and of Procedures and a Program for the Monitoring of the Application of These Standards for Québec* (the 2009 Agreement). Under the terms of the 2009 Agreement, the Régie de l'énergie , which is charged with ensuring the reliability of the electric transmission in Québec, retained NPCC and NERC as experts to develop reliability standards and monitoring program procedures for the Province.

The Régie de l'énergie, NERC and NPCC are parties to the September 24, 2014, *Agreement on the Implementation of the Québec Reliability Standards Compliance Monitoring and Enforcement Program* (the 2014 Agreement). Through the 2014 Agreement, the Régie de l'énergie retains the services of NPCC to monitor and assess the compliance of registered entities in Québec with the reliability standards adopted by the Régie with respect to electric power transmission in Québec.

On April 1, 2015, the Québec Reliability Standards Compliance Monitoring and Enforcement Program ("QCMEP"), which was developed jointly by the Régie de l'énergie, NPCC and NERC, came into effect. Together, the 2014 Agreement and the QCMEP detail the procedures and program for monitoring and enforcing mandatory electric power transmission reliability standards in Québec.

The Régie de l'énergie is a public body established by the *Act respecting the Régie de l'énergie* (the Act). Pursuant to its authority under the Act, the Régie de l'énergie, through a series of decisions in 2007, designated Hydro-Québec Contrôle des mouvements d'énergie (HQCMÉ), a division of Hydro-Québec TransÉnergie, as the Reliability Coordinator for Québec. In accordance with its mandate and as recognized in the 2009 Agreement, it is this entity that is responsible for the filing with the Régie de l'énergie for approval of reliability standards in Québec. HQCMÉ has filed for the approval of certain reliability standards and the Régie de l'énergie has made certain reliability standards mandatory in Québec and is continuing proceedings to make additional reliability standards mandatory in Québec.

NPCC also conducts reliability assurance activities within Québec, including but not limited to events analysis, Reliability Assessment and Performance Analysis and compliance investigations, consistent with the NPCC *Amended and Restated Bylaws*.

d) New Brunswick

On October 1, 2013, the Electricity Act (NB) and implementing regulations (together, "NB Electricity Act") amended how Reliability Standards are approved, monitored, and enforced in the province of New Brunswick. The NB Electricity Act designates NPCC as a compliance body and NERC as a standards body within the meaning of the NB Electricity Act. The New Brunswick Energy and Utilities Board (NBEUB) is an independent, quasi-judicial board that is responsible for regulating New Brunswick's electricity sector under the NB Electricity Act. The NBEUB has the responsibility to adopt and enforce reliability standards in New Brunswick.

As contemplated in the NB Electricity Act, NPCC and the NBEUB entered into a Service Contract dated August 10, 2016, whereby NPCC provides CMEP and other services for the NBEUB. Additionally, the NBEUB, NPCC, and NERC entered into a Memorandum of Understanding on August 10, 2016, which describes the roles and responsibilities of the three entities and facilitates data sharing. These two documents, along with the NB Electricity Act are the governing documents with respect to conducting CMEP and other reliability related activities in New Brunswick.

With respect to the approval of reliability standards, the NB Electricity Act provides that all of the NERC Reliability Standards that were effective in New Brunswick prior to October 1, 2013 continue to be effective in New Brunswick after October 1, 2013. Additionally, the New Brunswick Power Corporation ("NB Power") is required to file for approval, modification, or retirement of NERC Reliability Standards 60 days after a NERC Reliability Standard is approved, modified, or retired by the Federal Energy Regulatory Commission ("FERC"). The NBEUB rules on the filed Reliability Standard after considering (a) the potential impact on the reliability of the bulk power system, (b) the potential cost and benefits (c) the public interest, and (d) any other factors that the NBUEB considers relevant. The Electricity Act requires the NBEUB to notify NPCC and NERC of an application by NB Power with respect to reliability standards and provide for a 60 day comment period. The NBEUB is required to approve the reliability standards if there are not substantive modifications proposed from the FERC approved NERC Reliability Standard and there were no substantive comments filed. Amendments to the reliability standard to make them compatible with New Brunswick or Canadian law are considered non-substantive. The approval of reliability standards may be subject to a hearing for several reasons, including substantive comments from NPCC or NERC.

With respect to the monitoring and enforcement of the Reliability Standards in New Brunswick, the NB Electricity Act provides for NPCC to identify entities that must register with the NBEUB in the New Brunswick specific registry. Additionally, NPCC may carry out the compliance monitoring and assessment for the NBEUB and assist and advise the enforcement for the NBEUB, including financial penalties. NPCC is also permitted to carry out or exercise any power in the implementing regulations that is specific to the NBEUB, as provided for in the Service Contract. Additionally, NPCC has the powers of an inspector, which permits NPCC to audit and spot check entities within New Brunswick.

e) Nova Scotia

Nova Scotia Power Incorporated (NSPI), NPCC and NERC are parties to a May 11, 2010 Memorandum of Understanding regarding the approval and implementation of mandatory NERC reliability standards and NPCC Regional reliability criteria. Pursuant to the MOU's terms, NERC and NPCC filed standards and criteria with the Nova Scotia Utility and Review Board (NSUARB) for approval on June 30, 2010 and June 29, 2010, respectively. A decision from the NSUARB on both NERC and NPCC filings was rendered on July 20, 2011. Hence, the standards and criteria are mandatory in Nova Scotia and NSPI will be subject to the NERC compliance monitoring and enforcement program, as implemented by NPCC.

NPCC will conduct compliance and enforcement activities with respect to the standards and forward any non-compliance information and recommendations to the NSUARB. The NSUARB maintains the final authority with respect to enforcement in Nova Scotia and based on the recommendations from NPCC, may determine whether a violation has occurred and, if so, what remedial measures or non-monetary penalties should be imposed.

Regional Entity Division Functional Scope

NPCC's Regional Entity division functions in support of the ERO include:

- Active participation in the development of North American Reliability Standards for the bulk electric system, and as needed development of Reliability Standards applicable within the NPCC cross-border Regional Entity
- Monitoring and enforcement of approved Reliability Standards, including the registration of responsible entities, and as needed certification of such entities
- Assessment of the present and future reliability of the bulk power system
- Operational coordination and situation awareness support
- Event analysis and identifying lessons learned to improve reliability
- Effective training and education of reliability personnel
- Promoting the protection of critical electric infrastructure

In recognition of the delegated compliance role of Regional Entities as an important means to enhancing reliability, NPCC has designated a significant percentage of its staff resources to compliance monitoring and enforcement. NPCC has also developed and deployed a robust set of online tools for gathering data, analysis, and tracking of compliance information to support its ability to carry out its responsibilities in a cost effective manner.

NPCC has organized the remaining staff into program areas consistent with EPAct 2005 to address the other functions listed above. These experts in operations, planning and reliability analysis assist registered entities in assessing and improving reliability. It is in support of these areas that NPCC engages the majority of industry experts on its technical committees.

2018 Key Assumptions and 2018 Goals and Key Deliverables

NERC and the eight Regional Entities collaborated in the development of a common operating model with complementary roles and responsibilities, an ERO Enterprise Strategic Plan, and a set of business planning assumptions, goals, metrics and key deliverables for the 2017 through 2019 period. The results from that collaboration, which incorporated risks identified by the Reliability Issues Steering Committee, are included as a set of Shared Business Plan and Budget Assumptions that will be contained in Exhibit A to the NERC 2018 Business Plan and Budget

and may be referenced by the users of this document. NPCC activities that support ERO Enterprise Goals are detailed in each of the following program area sections.

2018 Overview of Regional Entity Division Cost Impacts

The proposed Regional Entity division assessment of $14,341,787 to support the budget is an increase of 0.6% compared to the 2017 assessment of $14,255,061.

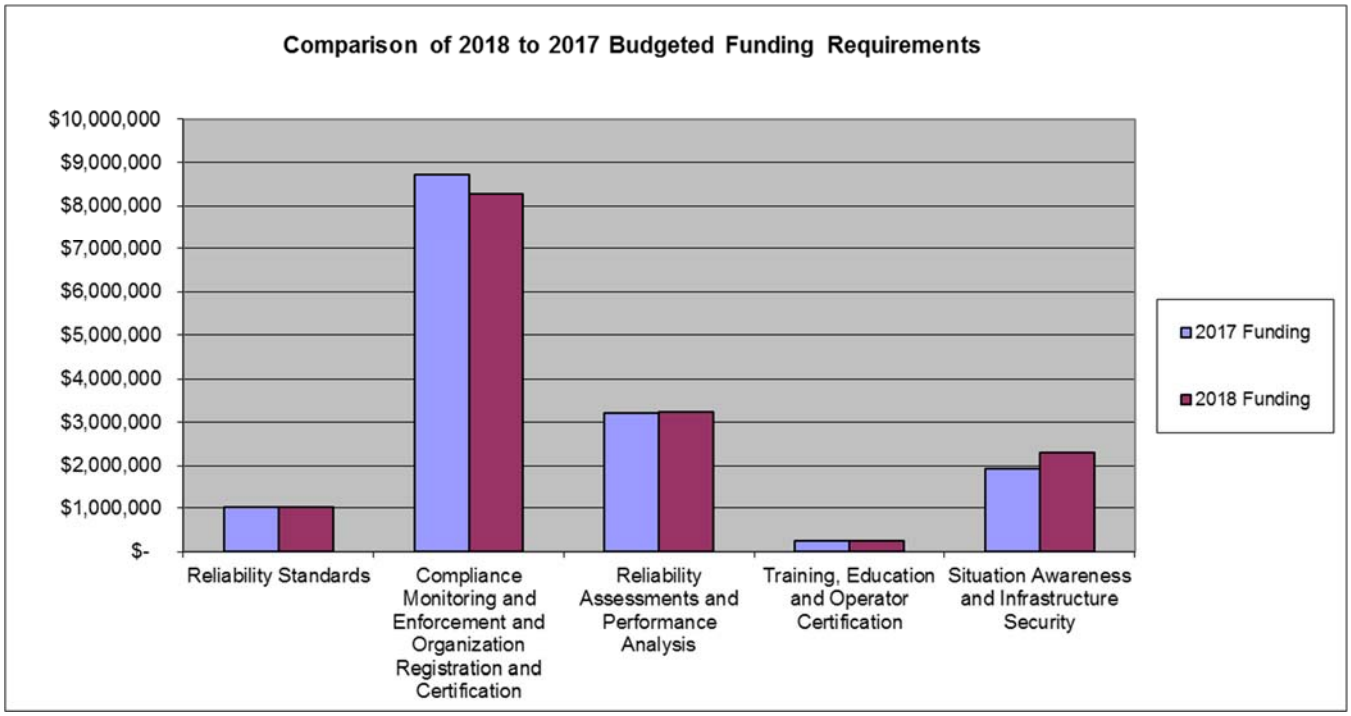
2017 Projections

Current year projections are taken into consideration in development of the budget. Expenses are currently projected to be on budget in all areas or slightly under budget. 2017 Projections reflect expectations based on the first quarter variance report. It is anticipated that projections could change throughout 2017 and would be reflected in each subsequent quarter's variance report.

Summary by Program

Program	Budget 2017	Projection 2017	Budget 2018	Variance 2018 Budget v 2017 Budget	Variance %
Reliability Standards	$ 1,022,328	$ 1,022,328	$ 1,010,246	$ (12,083)	-1.2%
Compliance Monitoring and Enforcement and Organization Registration and Certification	$ 8,726,049	$ 8,726,049	$ 8,293,748	$ (432,301)	-5.0%
Reliability Assessments and Performance Analysis	$ 3,206,966	$ 3,206,966	$ 3,240,721	$ 33,755	1.1%
Training, Education and Operator Certification	$ 248,658	$ 248,658	$ 249,051	$ 393	0.2%
Situation Awareness and Infrastructure Security	$ 1,943,053	$ 1,943,053	$ 2,313,202	$ 370,148	19.0%
Total	$ 15,147,054	$ 15,147,054	$ 15,106,967	$ (40,087)	-0.3%

This chart does not include allocation of working capital requirements among the Program Areas.



This chart does not include allocation of working capital requirements among the Program Areas.

Personnel Analysis

Total FTE's by Program Area	Budget 2017	Projection 2017	Direct FTEs 2018 Budget	Shared FTEs[1] 2018 Budget	Total FTEs 2018 Budget	Change from 2017 Budget
REGIONAL ENTITY DIVISION						
Operational Programs						
Reliability Standards	1.93	1.93	1.00	0.93	1.93	0.00
Compliance Monitoring and Enforcement and Organization Registration and Certification	17.00	16.00	16.00	0.00	16.00	-1.00
Training, Education, and Operator Certification	0.10	0.10	0.10	0.00	0.10	0.00
Reliability Assessment and Performance Analysis	5.83	5.83	4.90	0.93	5.83	0.00
Situation Awareness and Infrastructure Security	4.00	5.00	5.00	0.00	5.00	1.00
Total FTEs Operational Programs	**28.86**	**28.86**	**27.00**	**1.86**	**28.86**	**0.00**
Administrative Programs						
Technical Committees and Member Forums	0.50	0.50	0.50	0.00	0.50	0.00
General and Administrative	2.50	2.50	2.50	0.00	2.50	0.00
Information Technology	2.00	2.00	2.00	0.00	2.00	0.00
Legal and Regulatory	1.00	1.00	1.00	0.00	1.00	0.00
Human Resources	1.00	1.00	1.00	0.00	1.00	0.00
Accounting and Finance	1.00	1.00	1.00	0.00	1.00	0.00
Total FTEs Administrative Programs	**8.00**	**8.00**	**8.00**	**0.00**	**8.00**	**0.00**
Total FTEs	**36.86**	**36.86**	**35.00**	**1.86**	**36.86**	**0.00**

[1]A shared FTE is defined as an employee who performs both Regional Entity and Criteria Services division functions.

2017Budget and Projection and 2018 Budget Comparisons

Statement of Activities and Capital Expenditures
2017 Budget & Projection, and 2018 Budget

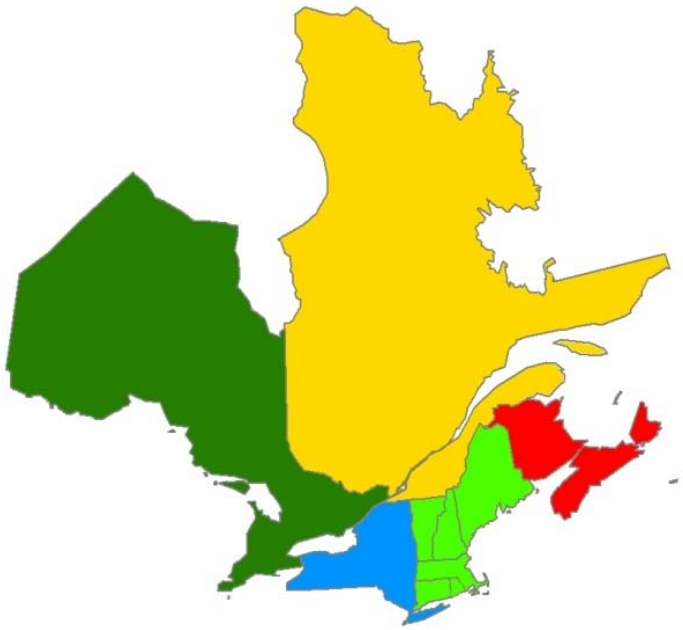
REGIONAL ENTITY DIVISION

	2017 Budget	2017 Projection	Variance[2] 2017 Projection v 2017 Budget Over(Under)	2018 Budget	Variance 2018 Budget v 2017 Budget Over(Under)
Funding					
ERO Funding					
ERO Assessments	$ 14,255,061	$ 14,255,061	$ -	$ 14,341,787	$ 86,726
Penalty Sanctions[1]	-	-	-	75,000	75,000
Total ERO Funding	**$ 14,255,061**	**$ 14,255,061**	**$ -**	**$ 14,416,787**	**$ 161,726**
Membership Dues	-	-	-	-	-
Testing Fees	-	-	-	-	-
Services & Software	-	-	-	-	-
Workshops	64,000	64,000	-	64,000	-
Interest	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Total Funding (A)	**$ 14,319,061**	**$ 14,319,061**	**$ -**	**$ 14,480,787**	**$ 161,726**
Expenses					
Personnel Expenses					
Salaries	$ 6,758,926	$ 6,758,926	$ -	$ 7,107,599	$ 348,673
Payroll Taxes	404,319	404,319	-	411,440	7,121
Benefits	1,415,603	1,415,603	-	1,476,378	60,774
Retirement Costs	847,223	847,223	-	825,353	(21,869)
Total Personnel Expenses	**$ 9,426,071**	**$ 9,426,071**	**$ -**	**$ 9,820,770**	**$ 394,699**
Meeting Expenses					
Meetings	$ 377,100	$ 377,100	$ -	$ 353,050	$ (24,050)
Travel	855,232	855,232	-	834,500	(20,732)
Conference Calls	37,000	37,000	-	37,000	-
Total Meeting Expenses	**$ 1,269,332**	**$ 1,269,332**	**$ -**	**$ 1,224,550**	**$ (44,782)**
Operating Expenses					
Consultants & Contracts	$ 2,009,000	$ 2,009,000	$ -	$ 1,877,640	$ (131,360)
Office Rent	809,700	809,700	-	810,700	1,000
Office Costs	679,100	679,100	-	664,760	(14,340)
Professional Services	1,041,000	1,041,000	-	960,000	(81,000)
Computer & Equipment Leases	-	-	-	-	-
Miscellaneous	50,000	50,000	-	50,000	-
Depreciation	250,000	250,000	-	269,000	19,000
Total Operating Expenses	**$ 4,838,800**	**$ 4,838,800**	**$ -**	**$ 4,632,100**	**$ (206,700)**
Total Direct Expenses	**$ 15,534,203**	**$ 15,534,203**	**$ -**	**$ 15,677,420**	**$ 143,217**
Indirect Expenses	**$ (413,149)**	**$ (413,149)**	**$ -**	**$ (416,453)**	**$ (3,304)**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)	**$ 15,121,054**	**$ 15,121,054**	**$ -**	**$ 15,260,967**	**$ 139,913**
Change in Assets	**$ (801,994)**	**$ (801,994)**	**$ -**	**$ (780,180)**	**$ 21,813**
Fixed Assets					
Depreciation	$ (250,000)	$ (250,000)	$ -	$ (269,000)	$ (19,000)
Computer & Software CapEx	276,000	276,000	-	115,000	(161,000)
Furniture & Fixtures CapEx	-	-	-	-	-
Equipment CapEx	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-
Allocation of Fixed Assets	0	0	-	0	-
Inc(Dec) in Fixed Assets (C)	**26,000**	**26,000**	**-**	**(154,000)**	**(180,000)**
TOTAL BUDGET (=B+C)	**$ 15,147,054**	**$ 15,147,054**	**$ -**	**$ 15,106,967**	**$ (40,087)**
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)	**$ (827,994)**	**$ (827,994)**	**$ -**	**$ (626,180)**	**$ 201,813**

(1) $75,000 of penalty sanctions collected to date and prior to June 30, 2017.

(2) 2017 Projections reflect expectations based on the 1st quarter statement of activities. It is anticipated that projections could change throughout 2017 and would be reflected in each subsequent quarter's statement of activities.

Section A – Regional Entity Division
2018 Business Plan and Budget



Section A — 2018 Regional Entity Division Business Plan and Budget

Reliability Standards Program

Reliability Standards Program Resources (in whole dollars)	2017 Budget	2018 Budget	Increase (Decrease)
Total FTEs	1.93	1.93	0.00
Direct Expenses	$658,082	$647,633	($10,448)
Indirect Expenses	$372,606	$375,586	$2,980
Other Non-Operating Expenses	$0	$0	$0
Inc(Dec) in Fixed Assets	($8,359)	($12,974)	($4,614)
Total Funding Requirement	$1,022,328	$1,010,246	($12,083)

Program Scope and Functional Description

The NPCC Reliability Standards Program Area operates in accordance with NPCC's filed and approved Delegation Agreement and NERC Rules of Procedure Section 300. The program supports the ERO standards program area roles and responsibilities, the 2018 ERO Enterprise Strategic Plan and 2018 Shared Business Plan and Budget Assumptions. NPCC's Reliability Standards Program Area provides an efficient and effective mechanism for stakeholders and the ERO to develop reliability standards which are clear, responsive to reliability and security risks, practical to implement, "results based", and are cost effective. The primary objectives of NPCC's Reliability Standards Program Area is to support the development of ERO standards which establishes "results-based" requirements for addressing reliability risks with due consideration given to cost effectiveness. NPCC supports the ERO efforts to develop reliability standards in a timely and efficient manner and which are responsive to FERC Directives and industry risk. ERO and Regional Reliability Standards must ensure the bulk electric system is planned, operated, and maintained in a manner that minimizes risks of cascading failures, avoids damage to major equipment, is responsive to risks, or limits interruptions of bulk power supply.

At the Regional level, the standards program area develops, and maintains NPCC Regional Reliability Standards, ERO Standards Variances for the northeast as required. In addition, the NPCC Reliability Standards Program Area provides oversight to ensure that NPCC's Regional Reliability Criteria contained in the form of Directories, are developed and maintained as necessary to implement, to augment, or to comply with NERC Reliability Standards, but which are not Reliability Standards. Regional Reliability Criteria may also address issues not within the scope of Reliability Standards, such as resource adequacy and conform to requirements in Section 313 of the NERC Rules of Procedure.

The NPCC Reliability Standards Program Area supports and participates in the development, revision, and maintenance of NERC ERO Reliability Standards, initiates new continent-wide reliability standards through the NERC Standards Authorization Request (SAR) process when necessary, and provides a forum for the comprehensive review and improvement of existing and developing reliability standards. NPCC also provides coordination and represents the other seven NERC Regional Entity for the NERC Enhanced Periodic Review process and participates on the Enhanced Periodic Review Standing Team EPRST. The EPRST reviews existing NERC

standards and grades them for quality and content in an effort to prioritize and improve the reliability benefit of the ERO Reliability Standards.

The NPCC Reliability Standards Program Area also facilitates and assists stakeholders with initiating SARs and Requests for Interpretation of ERO standards for those entities within the NPCC footprint. In 2017 NPCC instituted a feedback mechanism from the Compliance, Event Analysis, RAPA and Criteria Services program area which provides a process to identify and improve standards. The standards program area will receive input from these other program areas and take appropriate action to support the revision, retirement, or development of new standards to improve the ERO set of reliability standards and improve reliability of the Bulk Electric System. The NPCC Reliability Standards Program Area conducts its oversight and participation in the ERO standards development process by utilizing the NPCC Regional Standards Committee (RSC) to ensure transparency and facilitate stakeholder input.

The NPCC Reliability Standards Program Area supports the reliability of the bulk electric system by:

- Facilitating active participation of NPCC Regional industry stakeholders in all NERC Reliability Standards activities to promote the development of results-based, cost effective, clear and concise quality standards in a timely and efficient manner.
- Providing selective support for standard development activities as outlined in the NERC 2018-2020 Reliability Standards Development Plan (RSDP)
- Participating in and representing the other Regional Entities on the EPRST which evaluates need to revise existing standards, prioritizes the standards development projects for the future year's RSDP, and allows the Regions to identify opportunities to replace Regional Standards with Variances in the continent wide standards.
- Support ERO outreach during standard development by providing a forum for all NPCC representatives on the NERC drafting teams to raise issues, socialize concepts with stakeholders, and receive feedback on the standards during the development process to enhance efficiency and timeliness of standards development
- Assisting NERC with the evaluation of the standards from a "cost effectiveness" perspective by supporting ongoing pilots and participating in the development of a formal process.
- Promoting awareness by holding Regional workshops to provide outreach and conducting Regional Standards Committee meetings to inform and educate stakeholders on standards being developed, modified or maintained.
- Utilizing input received from the NPCC Regional feedback mechanisms, identify and initiate improvements to NERC standards.
- Actively participate and review the work of the NERC Reliability Issues Steering Committee (RISC) which identifies emerging risks to the BES.
- Coordinating and sharing activities and useful information such as presentations, implementation documents and training materials as necessary with Standards Program Areas from other Regions to enhance efficiencies and promote consistency amongst the Regions.
- Developing and maintaining Regional Standards as necessary to address Regional reliability related issues or risks and ensure those standards set more stringent reliability requirements than the associated NERC Reliability Standard or cover matters not covered by an existing NERC Reliability Standard all in accordance with Section 312 of the NERC Rules of Procedure.

- Pursuing retirement of Regional Standards through promoting the reliability objectives of those Regional Standards into the NERC Continent-wide standards and developing Variances to the NERC standards where possible to capture the reliability objectives of the Regional Standards.
- Maintaining and abiding by the NPCC Regional Standard Processes Manual assuring compliance with all FERC filed documents with respect to standards development.

2018 Key Assumptions

- The number of continent-wide Reliability Standards development projects is expected to 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 Reliability Standards projects will consist primarily of conducting periodic reviews on existing Reliability 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, Compliance Analysis and Certification, and Compliance Assurance) and support from across the ERO Enterprise.
- During the periodic review of Reliability Standards, any associated Regional Reliability Standards will be reviewed for potential incorporation as variances or as improvements to the continent-wide requirements. Regional and NERC Reliability Standards development processes may require modification to efficiently accomplish this task. NPCC will work with NERC and other Regional Entities as necessary on projects where there is a Regional Reliability Standard/variance.
- NPCC's Regional Reliability Standards development activity is expected to remain low, driven by requests that the Regional Entity may receive or reliability issues that are identified.
- In coordination with NERC's Standard Drafting Teams and consistent with current approaches, NPCC will 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.
- Following FERC approval, NPCC will assist with the transition of Reliability Standards to compliance monitoring and enforcement by supporting industry and auditor training or providing information regarding the intent of the Reliability Standard.
- The number of NERC and Regional standards interpretations is expected to remain low. However, implementation guidance requests may increase. The NPCC Reliability Standards program area will assist and facilitate support of these activities.
- Consistent with the NERC Rules of Procedure Sections 312 and 313, as continent wide standards continue to evolve, NPCC Regional Standards and Criteria will need to be continually reviewed to ensure they augment but do not add duplicity to the ERO standards.

2018 Goals and Key Deliverables

The Reliability Standards program goals and objectives for 2018 are grouped into six categories:

1) Participate in the ERO Results-Based Standards Development

- Participate in the annual development and revision of the NERC three year Reliability Standards Development Plan (RSDP)through review, commenting, and other RSC activities
- Participate in the NERC Standards Committee, as a representative of the NERC Regional Entities and NPCC Regional stakeholders to advance strategic initiatives, to measure the effectiveness and quality of standards, participate in standards EPR activities, ensure any outstanding FERC Directives are addressed, and coordinate and prioritize standards development projects
- Support further development of cost effectiveness principles using the "Cost of Risk Reduction Analysis" (CRRA) process and pilots. Continue to provide insights to NERC, based on NPCC experiences, regarding strategy for developing cost effectiveness analysis for standards and identify opportunities to identify cost of risk mitigation for the draft standards
- Participate in the development of ERO Reliability Standards within NERC's three-year standards work plan with the emphasis placed on reducing the amount of new FERC Directives issues by closer coordination with the Commission staff
- Conduct thorough reviews of all NERC standards being developed or revised and coordinate comments for Northeastern North America driving consensus to the extent possible through the Enhance Periodic Review Standing team and processes. Ensure all developing standards receive a review for adequate level of reliability, cost effectiveness and are technologically neutral and focused on achieving a reliability objective
- Assist NERC's review of all industry "Requests for Interpretations" of standards
- NPCC staff, along with NPCC solicited regional drafting team volunteers, will participate in the drafting of ERO standards affecting or potentially affecting reliability in the Eastern Interconnection and provide support for review and development of comments and propose improvements
- NPCC and its members will review and coordinate members' comments on FERC staff informal assessments of the ERO Enterprise as appropriate
- Participate in pre-ballot reviews of ERO standards and coordinate the development of consensus recommendations of the NPCC Members to the NERC Standards Drafting Team (SDT) and provide a list of any unaddressed issues to allow the Members to cast a ballot based on regional concerns to enhance the efficiency of the ERO standards development projects
- Review and identify issues and concerns raised in FERC NOPRs and NOIs for any and all standards related issues as appropriate
- Coordinate and evaluate proposed standards utilizing NPCC's technical task forces, working groups and committees
- Educate and notify stakeholders and regulators about issues related to standards development through various means such as webinars and workshops
- Provide outreach to industry trade groups such as the North American Generator Forum and North American Transmission Forum
- Provide a forum for NPCC review of proposed and posted standards related documents from the NERC Critical Infrastructure Protection Committee (CIPC) and NPCC Task

Force on Infrastructure Security and Technology (TFIST) such as but not limited to whitepapers and technical guidelines

- Participate in the NERC RISC and provide a Regional point of contact for all potential reliability related risks and gaps within the Northeast or as noted by NPCC's stakeholders
- Participate in and provide support to critical standards projects, such as CIP Supply Chain, Facility Ratings (IROL and SOL development), GMD, etc.
- Identify and initiate Regional Variances to the NERC Reliability Standards as soon as possible, allowing incorporation into the continent wide standard
- .
- Provide support and assistance to the ERO, as needed, for conducting Quality Review activities on NERC continent-wide standards
- Continue to develop new and innovative processes to better utilize the limited internal and external resources in the Region to enable sufficient technical review of posted standards and related materials
- Support the ERO and the relationships with FERC and applicable provincial governmental authorities for standards development activities as necessary to accomplish the ERO's strategic goals and objectives
- Participate in the improvement of NERC standards though lessons learned and various ERO and Regional feedback mechanisms using input from Compliance, RAPA, Event Analysis, and stakeholders
- Provide support to the Compliance Guidance Policy activities as required.
- Provide support to ERO staff for FERC related matters in the area of standards development such as pre-filing meetings, preparation of filings, and technical conference participation

2) Regional Standards Development

- NPCC does not plan on developing further Regional Standards but reserves the right to do so if a reliability issue exists that is not appropriate for continent-wide development and also will perform clarifications as needed to existing approved Regional Standards in accordance with all NERC Rules of Procedures and NERC and Regional Standards processes
- Conduct reviews for opportunities to include Regional Standards as Variances into the associated NERC continent wide standards as they individually undergo Enhanced Periodic Reviews
- Conduct periodic reviews of Regional Standards as necessitated by the revision and approval of any associated Continent-wide NERC reliability standards or further reliability related need.
- Conduct the development of any Québec Interconnection Wide variances to NERC continent wide standards using the NPCC Reliability Standards Development Process.

3) Standards Improvement

- Achieve NPCC Northeastern North American reliability goals and objectives by initiating, participating in, and efficiently completing standards related activities and promote these reliability objectives in continent-wide standard development projects
- Leverage internet and web based tools functionality to ensure inter-Regional consistency and quality of Regional Reliability Standards
- Support long-term strategy for standards improvement, help develop and initiate implementation of more efficient processes

- Identify any reliability related need for additional Regional Standards opportunities if continent-wide standards are not an appropriate or possible solution
- Ensure the topics addressed by the Reliability Standards parallel changing industry needs
- Participate in reliability metrics activities to identify potential measures for benchmarking of reliability and standards to determine if an adequate level of reliability is being achieved through the Enhanced Periodic Review Standing Team activities
- Identify opportunities and processes for cost-effectiveness CRRA analysis activities to determine the need to revise a standard during the EPR process
- Identify any emerging interconnection-wide reliability issues which may need standards solutions and forward to the NERC Reliability Issues Steering Committee.
- Identify opportunities to increase reliability through the revision of standards and their associated requirements

4) Business Practices Interface

- Coordinate the review of standards through NPCC RSC, staff, and other members participating in activities of the North American Electric Standards Review Board (NAESB)
- Identify potential market related issues for Regional Standards through NPCC RSC coordination and reviews

Based on the portion of professional/technical staff time and other resources devoted to Reliability Standards development, NPCC estimates that it will expend approximately 7% of its resources on this activity.

Resource Requirements

Personnel

- NPCC anticipates no need to hire additional personnel in this program area in 2018.

Reliability Standards Program

Funding sources and related expenses for the Reliability Standards section of the 2018 business plan are shown in the table below. Explanations of variances by expense category are included with the Supplemental Tables found in Section B.

Statement of Activities and Capital Expenditures 2017 Budget & Projection, and 2018 Budget Reliability Standards						
		2017 Budget	2017 Projection	Variance 2017 Projection v 2017 Budget Over(Under)	2018 Budget	Variance 2018 Budget v 2017 Budget Over(Under)
Funding						
ERO Funding						
	ERO Assessments	$ 1,022,328	$ 1,022,328	$ -	$ 1,005,230	$ (17,098)
	Penalty Sanctions	-	-	-	5,016	5,016
Total ERO Funding		**$ 1,022,328**	**$ 1,022,328**	**$ -**	**$ 1,010,246**	**$ (12,083)**
	Membership Dues	-	-	-	-	-
	Testing Fees	-	-	-	-	-
	Services & Software	-	-	-	-	-
	Workshops	-	-	-	-	-
	Interest	-	-	-	-	-
	Miscellaneous	-	-	-	-	-
Total Funding (A)		**$ 1,022,328**	**$ 1,022,328**	**$ -**	**$ 1,010,246**	**$ (12,083)**
Expenses						
Personnel Expenses						
	Salaries	$ 370,220	$ 370,220	$ -	$ 377,093	$ 6,873
	Payroll Taxes	21,273	21,273	-	21,390	116
	Benefits	97,411	97,411	-	98,851	1,441
	Retirement Costs	43,020	43,020	-	40,299	(2,721)
Total Personnel Expenses		**$ 531,925**	**$ 531,925**	**$ -**	**$ 537,633**	**$ 5,709**
Meeting Expenses						
	Meetings	$ 13,000	$ 13,000	$ -	$ 7,000	$ (6,000)
	Travel	103,157	103,157	-	93,000	(10,157)
	Conference Calls	-	-	-	-	-
Total Meeting Expenses		**$ 116,157**	**$ 116,157**	**$ -**	**$ 100,000**	**$ (16,157)**
Operating Expenses						
	Consultants & Contracts	$ 10,000	$ 10,000	$ -	$ 10,000	$ -
	Office Rent	-	-	-	-	-
	Office Costs	-	-	-	-	-
	Professional Services	-	-	-	-	-
	Computer & Equipment Leases	-	-	-	-	-
	Miscellaneous	-	-	-	-	-
	Depreciation	-	-	-	-	-
Total Operating Expenses		**$ 10,000**	**$ 10,000**	**$ -**	**$ 10,000**	**$ -**
	Total Direct Expenses	**$ 658,082**	**$ 658,082**	**$ -**	**$ 647,633**	**$ (10,448)**
Indirect Expenses		**$ 372,606**	**$ 372,606**	**$ -**	**$ 375,586**	**$ 2,980**
Other Non-Operating Expenses		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)		**$ 1,030,688**	**$ 1,030,688**	**$ -**	**$ 1,023,220**	**$ (7,468)**
Change in Assets		**$ (8,359)**	**$ (8,359)**	**$ -**	**$ (12,974)**	**$ (4,614)**
Fixed Assets						
	Depreciation	$ -	-	$ -	-	$ -
	Computer & Software CapEx	-	-	-	-	-
	Furniture & Fixtures CapEx	-	-	-	-	-
	Equipment CapEx	-	-	-	-	-
	Leasehold Improvements	-	-	-	-	-
	Allocation of Fixed Assets	(8,359)	(8,359)	-	(12,974)	(4,614)
Inc(Dec) in Fixed Assets (C)		**(8,359)**	**(8,359)**	**-**	**(12,974)**	**(4,614)**
TOTAL BUDGET (=B+C)		**$ 1,022,328**	**$ 1,022,328**	**$ -**	**$ 1,010,246**	**$ (12,083)**

Compliance Monitoring and Enforcement and Organization Registration and Certification Program

Compliance Monitoring and Enforcement and Organization Registration and Certification Program Resources (in whole dollars)	2017 Budget	2018 Budget	Increase (Decrease)
Total FTEs	17.00	16.00	-1.00
Direct Expenses	$5,366,656	$5,247,634	($119,022)
Indirect Expenses	$3,282,024	$3,113,668	($168,356)
Other Non-Operating Expenses	$0	$0	$0
Inc(Dec) in Fixed Assets	$77,369	($67,554)	($144,922)
Total Funding Requirement	$8,726,049	$8,293,748	($432,301)

Program Scope and Functional Description

The Compliance Monitoring and Enforcement and Organization Registration and Certification Program (CORC) Program scope covers: 1) the identification, registration and certification of those entities responsible for meeting the NERC Reliability Standards and any approved Regional Standards; 2) the implementation of the risk-based NERC Compliance Monitoring and Enforcement Program (CMEP) in the United States, including the compliance monitoring, assessment and enforcement of NERC Reliability Standards and Regional Reliability Standards. and 3) the implementation of compliance monitoring, assessment and enforcement recommendations in accordance with individual executed MOUs or Agreements in the Canadian Provinces of Ontario, Québec, New Brunswick and Nova Scotia.

The NPCC Compliance Committee (CC) is charged with providing objective stakeholder policy input to NPCC's implementation of the CMEP in the U.S. and compliance related activities under the above mentioned MOUs in the NPCC portion of Canada. With regard to NERC Reliability Standards and Regional Reliability Standards, the CC provides an oversight role of the independent NPCC compliance staff's implementation of the CMEP. In this oversight role the CC will review and endorse the processes used by the NPCC compliance staff in the conduct of the CMEP.

The NPCC compliance staff makes the initial and final determination of alleged violations and determines appropriate penalties and sanctions in accordance with the NERC *Sanction Guidelines*. To accomplish this objective, NPCC's compliance staff is further divided into four sub- program areas: Compliance Implementation and Registration; Compliance Entity Risk Assessment, Compliance Monitoring; and Compliance Enforcement.

Compliance Implementation, Registration and Certification

The Compliance Implementation and Registration sub-program is responsible for:

a) Continue to use the risk-based registration model to maintain an accurate registry and correctly identify all entities that are required to meet the NERC and Regional Reliability Standards.
b) Performing the annual review of the recently created enhanced registration database, assuring that all entity data, such as latest entity risk assessment data, BES asset listing, etc.is correct and up to date.
c)
d) Representing NPCC on the NERC –led Review Panel whose role is to make decisions related to resolving - identified registration issues, such as registered entities requests for a materiality assessment, an identification of an applicable subset of NERC Standard requirements, etc;
e) Engaging with those registered entities who are requesting a materiality assessment or an identification of an applicable subset of requirements in advance of these issues being presented to the NERC-led Review Panel;
f) Working within the ERO Enterprise on monitoring the progress of the development and implementation of new Registration and CMEP software reporting systems and tools.
g) Developing and maintaining all NPCC and NERC CMEP Compliance Procedures, Compliance Instructions and all other CMEP related documentation;
h) Developing and maintaining Performance Metrics that are used to measure the quality and effectiveness of CMEP Implementation and its impact on the reliability of the Bulk Electric System;
i) Coordinating the implementation of NPCC Compliance Staff responsibilities as they pertain to the executed MOU with each of the Canadian Provinces in the NPCC Region.
j) Day-to-day implementation of the CMEP;
k) Developing of NPCC's annual CMEP Implementation Plan;
l) Monitoring and assessment of guided self-certification, self-report, exception reporting, periodic data and complaint submittals;
m) Updating and maintaining theCMEP Data Administration Application (CDAA);
n) Implementing required changes and maintenaining the Registration and Compliance portions of the NPCC website.
o)
p) Participating on various NERC and NPCC working groups to influence changes to Compliance processes, and support commonality of registration, monitoring, auditing, and enforcement approaches.

Compliance Monitoring Program

The Compliance Monitoring Program is charged with conducting both on-site and off-site compliance audits, spot checks, and guided self-certifications of NERC Reliability Standards in accordance with the NERC Rules of Procedure and associated NPCC procedures developed under the NPCC Compliance Implementation Program. NPCC's Compliance Monitoring area provides supporting activities by implementation of the risk-based Compliance Monitoring and Enforcement Program (CMEP); and by use of consistent compliance monitoring practices focused on higher reliability risks. NPCC uses risk profiles from the IRAs (inherent risk assessments) as a baseline evaluation of reliability risks of an entity. NPCC also uses IRA summaries to guide its efforts to identifying key focus areas and evolving reliability risks. Internal Control Evaluations (ICE) are performed for registered entities that agree to identify key

focus areas for a CMEP engagement. The result is a list of reliability requirements that merit a continued level of focus.

NPCC also supports the ERO Enterprise learning effort, as well as NERC oversight of program implementation. In collaboration with NERC, NPCC supports outreach programs in new CIP versions and in implementation of CIP-014 with anticipated expansion in the number and type of registered entities that require guidance. Compliance engagements are performed on the basis of risk to the BES and take into account the ERO reliability risk priorities. The Reliability Assessment (RA) group performs an IRA of all registered entities and forwards results to the manager of compliance to develop a schedule. Previous performed IRAs are amended and updated based on identified triggers. The yearly schedule is produced consistent with Risk Assessment of registered entities and the desired frequency of CMEP engagements. The schedule is posted annually on NERC and NPCC public websites.

Flexibility may be used in the CMEP engagement frequency based on the risk assessment and performance based assessment of each entity scheduled for an audit, and changes requiring certification. NPCC compliance monitoring is focused on the most significant risks to the BES. CMEP engagement may be in the form of an audit, spot check or guided self-certification and are led by qualified senior NPCC Staff. Compliance Oversight Plans are developed for registered entities to address the relevant risks. NPCC also conducts outreach, training, and education as necessary to support the implementation of new Reliability Standards.

Findings include the identification of any possible violations. Contents and processing of audit and spot check reports are in accordance with NERC directives for reporting. Specific lessons learned are factored into the program to promote continuous improvement and are presented at workshops. An annual comprehensive guided self-certification program is established based on the NERC and NPCC Risk Elements. Spot checks are based on NPCC's assessment of follow–ups on entities that have previously violated a Reliability Standard, follow-up on entities that have been involved in a significant system event, and other requirements which at the discretion of NPCC could pose a higher risk to reliability if not followed properly.

Resources from the Compliance Audit Program are also used to implement the Certification process for entities intending to register as new TOPs, BAs or RCs, as well as certification reviews of changes made by existing TOPs, BAs and RCs that meet the threshold requiring same. These actions are performed in support of the Compliance Registration Program which encompasses the Certification process. Resources for this activity, which is independent of the audit process, depend on the scope, function, and location of the entity being certified.

Compliance Entity Risk Assessment

The Entity Risk Assessment group conducts activity that informs the risk-based approach for CMEP engagement scoping. They conduct an entity's IRA prior to scoping the compliance engagement to determine which CMEP tool will be used.

Entity risk also includes an assessment of an entity's Internal Controls which is used for further refinement of requirements to be included in the engagement. While separate ICE engagements are voluntary and must be agreed to by the entity, internal controls may also be reviewed as needed during an audit.

Compliance Investigation

A Compliance Investigation (CI) may be initiated at any time by NPCC in response to a system disturbance, complaint, or possible violation of a Reliability Standard identified by any other means. The CI process requires the establishment of an investigation team that coordinates with NERC and FERC as necessary; and also coordinates with the Situation Awareness Program Area.

Compliance Enforcement

In processing identified violations NPCC Compliance Enforcement strives to promote both timeliness and transparency of compliance results utilizing a risk-based compliance enforcement approach, including those efforts associated with meeting the enforcement metrics described below. In addition NPCC promotes the use of self-identification of non-compliance and implementation of discretion, including increased utilization of streamlined tracks such as FFT and discretion as shown below.

Compliance Enforcement responsibilities:

a) Issuing all applicable notices including the Notice of Preliminary Screen; Notice of Compliance Exception; Notice of Possible Violation (NOPV), Notice of Find, Fix and Track (FFT) Treatment; Notice of Alleged Violation (NOAV), and the Notice of Confirmed Violation (NOCV);
b) Conducting comprehensive enforcement investigations based on the facts and circumstances related to all possible violations of Reliability Standards, whether identified in an audit, a self-report, complaint, or other source, and determining whether further action is warranted;
c) Reviewing, approving, submitting to NERC and tracking the progress of all mitigation plans /mitigating activities associated with confirmed violations or noncompliances;
d) Coordinating settlement activities once they have been initiated and submitting settlement agreements to NERC for approval;
d) Identifying and processing applicable moderate violations for the FFT Process;
e) Administer both the compliance exception process and the self-logging process for identified minimal noncompliances;
f) Coordinating the identification of possible NERC Reliability Standards revisions and submit issue for proper implementation. Revisions will be based on experiences observed from compliance monitoring activities, enforcement investigations, and event analysis. Work closely with NPCC Reliability Standards Program Area
g) Following up on verifying that proposed Reliability Standards have been implemented and are effective in improving the standards.
h) Participating in the Hearing Process by representing NPCC before the Hearing Body. Compliance Hearings would be conducted at NPCC under the supervision of a qualified, independent hearing officer contracted by NPCC;
i) Issuing Remedial Action Directives when appropriate; and
j) Implementing the risk-based compliance enforcement model including :
    a. Notifying the registered entity, within 60 days on average, whether a non-compliance will proceed through enforcement, be treated as a compliance exception or additional information is needed ("Triage");
k) Developing and monitoring a set of enforcement metrics that support NERC's Strategic Plan and Oversight Program
l) Processing violations based on the individual executed MOUs or Agreements in the Canadian Provinces of Ontario, Québec, New Brunswick and Nova Scotia.

2018 Key Assumptions and Cost Impacts

2017	Projected 2018
8 On-Site Audits	4 On-Site O&P Audits
12 On-Site CIP Audits	10 On-Site CIP Audits
32 Off-Site Audits	30 Off-Site O&P Audits
11 Off-Site CIP Audits	15 Off-Site CIP Audits
15 Spot Checks	15 Spot Checks
25 Guided self-certifications	25 Guided self-certifications
50 Inherent Risk Assessments	50 Inherent Risk Assessments
10 On-site Internal Control Evaluations	4 On-site O&P Internal Control Evaluations
	5 On-Site CIP Internal Control Evaluations
100 Violations (Estimated)	120 Violations (Estimated)
Settlements Covering 50 Violations	Settlements Covering 50 Violations
2 Hearings (Unbudgeted)	2 Hearings (Unbudgeted)
1 CI (Estimated)	1 CI (Estimated)
2 Entity Certifications	4 Entity Certifications

- Regarding the Compliance Audit Program, Technical Feasibility Exception (TFE) reviews are conducted both on-site at the entity's facility and at the NPCC offices when possible. TFE's continue to be requested as entities replace and install new equipment/devices/components that meet the criteria set forth in Rules of Procedure Appendix 4D. Compliance estimates four on-site reviews will be performed in 2018.
- Decrease in audit costs reflects Risk Assessment activity that is the basis for entity engagement scoping. The Risk Assessment includes an assessment of an entity's Internal Controls which is used for future reduction in engagement scoping and frequency of engagements.
- Potential increases due to the newly identified role related to implementing the QCMEP in Québec and the continuing role of implementing the NB CMEP in New Brunswick.
- The 2018 Business Plan projects no significant increases in Enforcement Processing activities over the 2017 Budget.
- The 2018 Business Plan projects the need for one Compliance Investigation. These Compliance Investigations are manpower intensive for NPCC staff (requiring allocation of more resources and potentially higher than normal costs).

2018 Goals and Key Deliverables

- Conduct 2018 CMEP consistent with a risk-based compliance monitoring and enforcement model, assessing IRA; conducting voluntary ICE; and expanding the use of compliance exceptions and the self-logging program for disposition of minimal violations.
    - Continue to process identified violations as effectively as possible, including the timely identification of a violation and its disposition method (e.g. compliance exceptions; FFT; etc.), and the timely issuance of appropriate notification to the registered entity and NERC;
    - Continue to implement settlement process when applicable and send proper notifications to NERC and FERC and continue to enhance the settlement process

by modifying existing practices and adopting new practices to reduce the duration of settlement negotiations without sacrificing the rigor and quality of the negotiated settlements;
    - Develop and analyze appropriate performance metrics that track settlement process duration and utilize results of analysis to further enhance process.
    - Conduct necessary Hearings related to resolution of outstanding disputes regarding violations and/or sanctions. Send results of hearings to NERC and FERC.
- Identify potential issues related to NERC Reliability Standards as a result of compliance monitoring, enforcement and event analysis activities.
- Implement proposed changes to NERC Reliability Standards utilizing existing mechanisms.
- Verify effectiveness of proposed changes to reliability standards.
- Provide detailed response to NERC Annual FFT/Compliance Exception Survey;
- Implement compliance responsibilities identified in the approved Canadian MOUs;
- Annual report to NERC and Régie on NPCC implementation of QCMEP
- Annual report to NERC and New Brunswick Electric Utility Board (NBEUB) on NPCC implementation of NB CMEP.
- Provide NPCC Regional Entity input, through participation in appropriate NERC compliance committees, on policy and implementation issues related to compliance and enforcement including the development of compliance elements for all new or revised NERC Reliability Standards;
- Provide required information to NERC on a timely basis including reporting of alleged violations and confirmed violations
- Track the progress of report status and approve mitigation plans and mitigating activities;
- Conduct 2018 Compliance Engagement Schedule based on risk to the BES and number of registered entities and promote the ERO Risk-Based Approach initiatives by:
    - Utilizing the Audit Checklist and Auditor's Handbook for all on-site and off-site audits
    - Preparing an Inherent Risk Assessment for all scheduled engagements and Internal Control Assessment for all entities that volunteer for one;
- Assure that NPCC Staff is trained to conduct Entity Risk Assessment and CMEP engagements including CIP Compliance Audit training;
- Assure that NPCC staff is trained to conduct Certification of entities intending to Register as BA, RC or TOP for the first time, or Certification Reviews of changes by existing BAs, RCs or TOPs that meet the criteria requiring a Certification Review;
- Continue to implement compliance reform consistent with a risk-based approach by being an integral participant in committees and workgroups that are involved in the development of polices related to the implementation of a risk-based compliance and enforcement model;
- Continue to expand the utilization of compliance exception and self-logging, as it relates to the processing of minimal noncompliances;
- Continue collaboration with ERO Enterprise on consistent compliance monitoring and enforcement practices specifically those with higher reliability risks.
- NPCC will collaborate with NERC to promote better coordination, planning, delivery and management of training efforts across the enterprise through a unified learning

management system (LMS), without adversely impacting region-specific training requirements;
- Continue to implement physical security outreach and cyber security outreach by visiting registered entity sites to perform an assessment of their physical security, evaluate their cyber security and supply recommendations for improvements;
- Provide outreach to the registered entities, related to the latest status of the development and implementation of the ERO Enterprise Registration and CMEP software reporting systems and tools;
- Work with ERO Enterprise, through NPCC participation on the NERC-led Review Panel, to propose a list of possible ROP enhancements related to the NERC-led Review Panel processes and procedures.
- Conduct 2018Compliance Workshops and interim information sessions for registered entities as necessary as a part of the Training and Education program area.
- Continue to promote practices to enhance the benefits of the self-reporting of violations by the registered entity. This could include the emphasis on the benefits of a registered entity improving its internal processes used for identifying and submitting self-reports, improvement in the way Regional Entities process self-reports, and the streamlining and standardizing of the amount and type of data needed to evaluate a self-report.

Based on the portion of professional/technical staff time and other resources devoted to Compliance monitoring and enforcement and organizational registration and certification, NPCC estimates that it will expend 54% of its resources on this activity.

Resource Requirements

Personnel

- There is a decrease of one FTE in 2018 from the 2017 budget. This is the result of reprioritization during 2017.

Consultants and contracts

- In 2018, contractor costs will continue to decrease due to the implementation of the risk-based approach. With a risk and performance based assessment of each registered entity, compliance engagements will transition to a periodicity more reflective of the risk profile of the entity such that some will result in audits which are more in-depth while others may have a reduced scope which will result in spot checks or guided self-certifications.

Compliance Monitoring and Enforcement and Organization Registration and Certification Program

Funding sources and related expenses for the compliance enforcement and organization registration and certification section of the 2018 business plan are shown in the table below. Explanations of variances by expense category are included with the Supplemental Tables found in Section B.

Statement of Activities and Capital Expenditures
2017 Budget & Projection, and 2018 Budget
Compliance Monitoring and Enforcement and Organization Registration and Certification

	2017 Budget	2017 Projection	Variance 2017 Projection v 2017 Budget Over(Under)	2018 Budget	Variance 2018 Budget v 2017 Budget Over(Under)
Funding					
ERO Funding					
ERO Assessments	$ 8,084,046	$ 8,084,046	$ -	$ 7,610,165	$ (473,881)
Penalty Sanctions	-	-	-	41,580	41,580
Total ERO Funding	**$ 8,084,046**	**$ 8,084,046**	**$ -**	**$ 7,651,745**	**$ (432,301)**
Membership Dues	-	-	-	-	-
Testing Fees	-	-	-	-	-
Services & Software	-	-	-	-	-
Workshops	-	-	-	-	-
Interest	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Total Funding (A)	**$ 8,084,046**	**$ 8,084,046**	**$ -**	**$ 7,651,745**	**$ (432,301)**
Expenses					
Personnel Expenses					
Salaries	$ 2,749,908	$ 2,667,408	$ (82,500)	$ 2,716,635	$ (33,273)
Payroll Taxes	179,504	172,004	(7,500)	171,841	(7,663)
Benefits	519,457	506,707	(12,750)	524,801	5,344
Retirement Costs	290,486	279,236	(11,250)	282,356	(8,130)
Total Personnel Expenses	**$ 3,739,356**	**$ 3,625,356**	**$ (114,000)**	**$ 3,695,634**	**$ (43,722)**
Meeting Expenses					
Meetings	$ 23,800	$ 23,800	$ -	$ 9,000	$ (14,800)
Travel	329,500	322,750	(6,750)	289,000	(40,500)
Conference Calls	-	-	-	-	-
Total Meeting Expenses	**$ 353,300**	**$ 346,550**	**$ (6,750)**	**$ 298,000**	**$ (55,300)**
Operating Expenses					
Consultants & Contracts	$ 1,274,000	$ 1,274,000	$ -	$ 1,254,000	$ (20,000)
Office Rent	-	-	-	-	-
Office Costs	-	-	-	-	-
Professional Services	-	-	-	-	-
Computer & Equipment Leases	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Depreciation	-	-	-	-	-
Total Operating Expenses	**$ 1,274,000**	**$ 1,274,000**	**$ -**	**$ 1,254,000**	**$ (20,000)**
Total Direct Expenses	**$ 5,366,656**	**$ 5,245,906**	**$ (120,750)**	**$ 5,247,634**	**$ (119,022)**
Indirect Expenses	**$ 3,282,024**	**$ 3,282,024**	**$ -**	**$ 3,113,668**	**$ (168,356)**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)	**$ 8,648,680**	**$ 8,527,930**	**$ (120,750)**	**$ 8,361,302**	**$ (287,379)**
Change in Assets	**$ (564,634)**	**$ (443,884)**	**$ 120,750**	**$ (709,557)**	**$ (144,922)**
Fixed Assets					
Depreciation	$ -	-	$ -	$ -	$ -
Computer & Software CapEx	151,000	151,000	-	40,000	(111,000)
Furniture & Fixtures CapEx	-	-	-	-	-
Equipment CapEx	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-
Allocation of Fixed Assets	(73,631)	(73,631)	-	(107,554)	(33,922)
Inc(Dec) in Fixed Assets (C)	**77,369**	**77,369**	**-**	**(67,554)**	**(144,922)**
TOTAL BUDGET (=B+C)	**$ 8,726,049**	**$ 8,605,299**	**$ (120,750)**	**$ 8,293,748**	**$ (432,301)**
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)	**$ (642,003)**	**$ (521,253)**	**$ 120,750**	**$ (642,003)**	**$ 0**

Reliability Assessment and Performance Analysis Program

Reliability Assessment and Performance Analysis Program Resources (in whole dollars)	2017 Budget	2018 Budget	Increase (Decrease)
Total FTEs	5.83	5.83	0.00
Direct Expenses	$2,106,675	$2,145,368	$38,692
Indirect Expenses	$1,125,541	$1,134,543	$9,002
Other Non-Operating Expenses	$0	$0	$0
Inc(Dec) in Fixed Assets	($25,251)	($39,190)	($13,939)
Total Funding Requirement	$3,206,966	$3,240,721	$33,755

Program Scope and Functional Description

NPCC, through its top technical committee, the Reliability Coordinating Committee (RCC), integrates the deliverables of its Task Force's and Working Group's Reliability Assessment and Performance Analysis related activities. Consistent with the applicable NERC Reliability Standards, these efforts include:

- Reviewing the adequacy of the NPCC systems to supply load considering forecast demand, installed and planned supply and demand resources and required reserves; and,
- Assessing the impact of planned transmission and resource additions or modifications on NPCC system reliability.

Seasonal assessments of the overall NPCC resource adequacy assessments are performed and possible actions to mitigate any potential problems are identified. NPCC reviews operations and disturbances both internal and external to the Region in order to identify any lessons to be learned and recommends any necessary follow-up actions.

If appropriate, enhancements to Regional Standards or NPCC's more stringent, Regionally-specific reliability requirements are also recommended. NPCC promotes and conducts both inter-Area and inter-Regional studies to enhance reliability and operational effectiveness, and provides a forum for the discussion and coordination of operating issues within the NPCC Region and with other Regions.

2018 Key Focus Areas

In collaboration with NERC, Key Focus area activities for 2018 include:

- ✓ Integration of RAPA information systems for assessments and associated data requirements, including expanded and enhanced enterprise-wide data collection and analysis systems and capabilities for performance analyses, with a focus on independent and technically sound reliability assessments supporting delivery of high quality reports (e.g., Long-Term Reliability Assessment, short-term special assessments, probabilistic scenario assessments, and the 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 impacts of new technologies, changing resource or demand resource composition, and environmental related regulations or legislation; support for ERO activities to identify key

reliability risks and appropriate risk control projects designed to enhance reliability or mitigate risks.

- Developing and tracking of metrics associated with Essential Reliability Services;
- Developing 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 special reliability assessments (6-18 month horizon replacing the current summer and winter assessments), which focus on specific reliability issue risk areas and geographic areas with specific reliability concerns, while also allowing for regional assessments;
- Supporting the common approach developed for NERC reliability assessments to ensure consistent treatment of resource and reliability evaluations;
- Advancing analytical capabilities for identifying and determining reliability risks and conducting various reliability assessments by:
  - Integrating the analysis and measures of the identified essential reliability services into the NERC 2018 Long-Term Reliability Assessment;
  - 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;
  - Enhancing the capability for post event analysis, including ensuring the timely and accurate compilation and creation of steady state and dynamic simulation model cases for use in the investigation and analysis of major power system disturbance events.

✓ NPCC supports, through the Eastern Interconnection base case designee agreement, the 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.

✓ 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.

Eastern Interconnection Reliability Assessment Group

The primary function of the Eastern Interconnection Reliability Assessment Group (ERAG) is to support reliability of the bulk-power system in the Eastern Interconnection through periodic reviews of generation and transmission expansion. These assessments are conducted by the ERAG Steering Committees. The assessment-related activities indicated for the ERAG Management and Steering Committees below, are done in support of ERO Goal 3: "*Identification and Mitigation of Significant Risks to Reliability*."

In addition, ERAG has the responsibility to facilitate the development of the annual set of seasonal and future steady state and dynamic simulation base cases for use by the Regional Entities and other industry groups in the Eastern Interconnection. This is done through the ERAG Multi-Regional Modeling Working Group (MMWG). The base case compilation and development-related activities indicated for the ERAG Management and MMWG below are done in support of ERO Goal 3 related contributing activity to: "Develop guidelines and industry practices to maintain accurate system models that include the resources (synchronous and inverter based), load, and controllable devises providing essential reliability services." NPCC participates in the ERAG activities as one of the six Eastern Interconnection Regional Entities.

NPCC supports maintenance of the BESnet application and the processing of the Regional BES Exception Requests (ERs), including technical validation of the definition and exception requests periodic reviews of network changes affecting BES determinations, as well as requests for registration and certification reviews. Processing of BES Exception requests and recertification of previously approved BES Exception Requests are not expected to significantly impact resources requirements in this program area for 2018.

NPCC RAPA staff participates with the ERAG Management Committee, ERAG Steering Committee and ERAG Working Group and acts as the liaison between the ERAG MMWG and the NPCC SS-37 Working Group; activities include:

ERAG Management Committee Activities 2018 Goals and Deliverables

- ✓ Oversee the steady state and dynamic simulation base case data compilation and development;
- ✓ Oversee ERAG Multi-Regional Modeling Working Group (MMWG) changes to the dynamics base cases;
- ✓ Oversee MMWG effort to make necessary changes to the modeling of governor-turbine control systems to achieve frequency response that more closely reflects actual response during system frequency deviation events;
- ✓ Oversee the ERAG assessments of anticipated inter-Regional, inter-Balancing Authority transfer limit conditions and sensitivities. ERAG is considering different assessment approaches to enhance the way assessments are conducted to provide more industry value from the assessment results. Coordinate the effort with NERC Assessment Program staff;
- ✓ Develop ERAG Strategic Direction (i.e. anticipated new developments in MMWG process and system assessments); Resolve any issues with application of the ERAG MMWG non-disclosure agreement process so that base cases and assessments have sufficient protections in place for use and transmittal of confidential data and information; and,
- ✓ Develop and approve the ERAG activity budgets.

Multi-Regional Modeling Working Group 2018 Goals and Deliverables

- ✓ Facilitate the completion of the steady state and dynamic simulation base case data compilation and development for the 2018 series of cases. This will include 12 steady state base cases and 8 dynamic simulation base cases;
- ✓ Check and confirm that the dynamic model data passes all applicable checks and acceptance criteria. Include 60 second steady state simulation of each case to detect numerical errors;
- ✓ Apply changes to the MMWG dynamics case so they are available for interconnection dynamics studies;
- ✓ Incorporate dispatch information into the future and seasonal ERAG MMWG base cases so that the dispatches are more closely aligned with economic dispatch practices;
- ✓ Apply the web-based System Dynamics Data Base program during the development of the 2018series of dynamics base cases;
- ✓ Continue to improve the representations of the governor-turbine plant control models at most generators. Recommend the necessary changes in the models for specific generators;
- ✓ Apply MMWG base case non-disclosure agreement process so that MMWG cases continue to have sufficient protections in place for use and transmittal of confidential data and information; and,
- ✓ Verify that procedures in the MMWG manual are followed.

ERAG System Assessments 2018 Goals and Deliverables

- ✓ Conduct the 2018 ERAG Assessments and prepare the ERAG Assessment Reports, including, the assessments of anticipated inter-Regional, inter-Balancing Authority transfer limit conditions and sensitivities;
- ✓ Consider different assessment approaches to enhance the way assessments are conducted; and,
- ✓ Coordinate Assessment efforts with the NERC Reliability Assessment and System Analysis (RASA) Program staff to incorporate any risk-based or other approaches to supplement NERC Assessments.

2018 NERC Activities

NPCC will provide the Regional perspective with judicious NPCC RAPA staff participation on selective NERC Planning and Operating Committees and key related NERC Subcommittees, Task Forces and Working Groups which include:

- ✓ Essential Reliability Services Working Group (ERSWG);
- ✓ Load Modeling Task Force (LMTF);
- ✓ Protection System Mis-operations Task Force (PSMTF);
- ✓ Demand Response Availability Data System Working Group (DADSWG);
- ✓ Generating Availability Data System Working Group (GADSWG);
- ✓ Transmission Availability Data System Working Group (TADSWG);
- ✓ Power Plant Model Verification Task Force (PPMVTF);
- ✓ Reliability Assessment Subcommittee (RAS);
- ✓ Probabilistic Assessment Working Group (PAWG);
- ✓ System Analysis and Modeling Subcommittee (SAMS);
- ✓ Performance Analysis Subcommittee (PAS);
- ✓ Misoperation Information Data Analysis System (MIDAS); and,
- ✓ Incorporating any probabilistic reliability metrics required for the 2018 NERC Long-Term Reliability Assessment through the NPCC 2018 Long Range Adequacy Overview.

ERO – Executive Management Group (EMG) 2018 Activities

Provide analytic support for the ERO-EMG:

- ✓ Bulk Electric System Exception Process Working Group (BEPWG);
- ✓ ERO-RAPA Group; and,
- ✓ Other activities as directed by the ERO-Executive Management Group.

2018 Goals and Key Deliverables

Task Force on Coordination of Planning

The primary mission of the NPCC Task Force on Coordination of Planning (TFCP) is to promote reliability through the coordination of NPCC Area and NERC planning processes and activities. In addition, the TFCP provides technical support regarding operating expertise to the NPCC Regional Standards Committee and the NPCC Compliance Committee as requested, and provides support and technical input for related BES risks identified by the NERC Reliability Issues Steering Committee (RISC) and the NERC Essential Reliability Services Working Group.

The Task Force on Coordination of Planning activities indicated below are done in support of ERO Goal No. 3 "*Identification and Assessment of Significant Risks to Reliability*" and ERO Goal No. 4 "*Identification and Assessment of Emerging Risks to Reliability.*" A related contributing activity to ERO Goal No. 3 is to "Develop advanced and probabilistic methods to evaluate resource adequacy." Related contributing activities associated with ERO Goal No. 4

include "Enhance reliability assessments to reflect changing resource mix behavior, including distributed energy resources and essential reliability services, using probabilistic approaches that consider the variable and energy-limited nature of the evolving resource mix," and "Assess risks associated with cross sector dependencies and single points of disruptions."

TFCP Reliability Assessment and Performance Analysis 2018 Goals and Deliverables

- Coordinate NPCC responses to NERC Essential Reliability Services Working Group recommendations with the Task Force on Coordination of Operation and the Task Force on System Studies to ensure that developments in the NERC Planning Committee and its Subcommittees are addressed;
- Coordinate the development of additional Criteria as necessary, and track any new and developing standards through the Regional Standards Committee;
- Monitor the development of Bulk Power System (BPS) Regional Standard;
- Oversee NPCC Directory No. 1 Implementation Plan (Dated: September 30, 2015);
- Through the CP-8 Working Group:
    - conduct the annual NPCC Long Range Adequacy Overview and associated NERC RAS requested scenarios and/or special probabilistic studies/assessments;
    - Conduct a review of NPCC Interconnection Assistance Reliability Benefits;
- Evaluate and approve NPCC Area Transmission Reviews;
- Evaluate and approve NPCC Area reviews of Resource Adequacy;
- Coordinate, monitor, review, and make recommendations on the retirement of existing in-service Special Protection Systems (SPS)Remedial Action Schemes (RAS); and the implementation of proposed new or modified SPS/RAS;
- Monitor industry practices and make recommendations to NPCC on transmission adequacy standards related to intermittent generation such as wind or solar-photovoltaic and demand-side resources; and,
- Lead the NPCC Task Forces in the completion of the review and revision the *A10 Criteria–NPCC Classification of Bulk Power System Elements*.

TFCP Reliability Assessment and Performance Analysis 2018 Goals and Deliverables

- Support related reliability activities, including consideration of any requests for sub-regional assessments or NPCC's identification of the necessity for such assessments consistent with NERC Rules of Procedure section 805, associated with implementation of the State related resource/environmental initiatives;
- Monitor the actions of applicable NERC Subcommittees in the areas of resource adequacy, system protection and system control;
- Through the CP-8 working Group, review the load shape assumption used in NPCCC Multi-Area Probabilistic Reliability Assessments;
- Review and comment on the development of NERC Standards through the RSC;
- Monitor the developments in fuel supply, demand resources, energy efficiency, and conservation methods including all intermittent renewable resources, including embedded distributed resources;
- Support the NPCC Regional Standards Committee (RSC) as required; and,
- Keep informed on studies and developments with neighboring systems which might impact NPCC.

TFCP Reliability Assessment and Performance Analysis 2018 Goals and Deliverables

- Monitor the process for the annual review and updating of the NPCC Electric System Regional Map and the NPCC Load, Capacity, Energy, Fuel and Transmission Report (LCEF&T);
- Keep informed of the NERC Planning Committee and other subcommittee activities to determine their impact on the NPCC and any potential adjustments to NPCC Criteria;
- Coordinate with NERC regarding the development of standards for dynamic system controls; and,
- Review Events Analysis Lessons Learned using the Events Analysis discussion/review template.

Task Force on System Studies

The primary mission of the NPCC Task Force on System Studies (TFSS) is to provide active overall coordination of system studies of the reliability of the interconnected bulk power systems and for the review of certain NPCC documents. In addition, the TFSS provides technical support regarding operating expertise to the NPCC Regional Standards Committee and the NPCC Compliance Committee, and provides support and technical input for related BES risks identified by the NERC Reliability Issues Steering Committee (RISC) and the NERC Essential Reliability Services Working Group.

The Task Force on System Studies activities indicated below are done in support of ERO Goal No. 3 "*Identification and Assessment of Significant Risks to Reliability*" and ERO Goal No. 4 "*Identification and Assessment of Emerging Risks to Reliability.*" A related contributing activity to ERO Goal No. 3 is to "Develop guidelines and industry practices to maintain accurate system models that include the resources (synchronous and inverter based), load, and controllable devices providing essential reliability services." A related contributing activity to ERO Goal No. 4 is to "Develop sufficiency/adequacy guidelines for essential reliability services, including considerations of reliability attributes under a more diverse resource mix and changing load behaviors, such as ramping, reserve services and voltage support."

TFSS Reliability Assessment and Performance Analysis 2018 Goals and Deliverables

- ✓ Review and recommend approval of Area Transmission Reviews, in accordance with the "Guidelines and Procedures for NPCC Area Transmission Reviews" (Appendix B of Directory No. 1), based on material presented by the Areas. These reviews assess the impact of planned transmission and resource additions or modifications on system reliability, and determine the Area's conformance with the Basic Criteria. Through the Area Transmission Reviews, re-evaluate the performance and classification of existing SPSs and Dynamic Control Systems;
- ✓ Review and classify new and modified Special Protection Systems and/or Remedial Action Schemes, in accordance with the Appendix B, Procedure for the Review of a Special Protection Systems, of NPCC Directory No. 7, "*Special Protection Systems*";
- ✓ Review and Implement the NPCC A-10 Criteria:
    - Coordinate with TFCP to complete the review and revision of the A-10 document;
    - Review and recommend approval of changes to the NPCC list of bulk power system elements, in accordance with the "*Classification of Bulk Power System Elements*" (Document A-10); and,
    - Update the NPCC BPS List;

- ✓ Review and process Multiple Circuit Tower exclusions in accordance with NPCC Directory No. 1, Appendix E;
- ✓ Update the Multiple Circuit Tower Exclusion List;
- ✓ Perform annual review and update of the Major Project List;
- ✓ Through the SS-37 Working Group:
  - Annually develop a library of power flow base cases and associated dynamic cases. The NPCC cases will also be used to support the development of the library of power flow and dynamic cases for the Eastern Interconnection; in addition: update SS-37 Procedure Manual and other SS-37 documents including the Master Tie Line Data and Interchange Schedule;
  - Provide mid-term updates to the ten-year-out cases in the NPCC Library; and,
  - Perform event replication by benchmarking simulations against actual system performance.
- ✓ Perform the NPCC Under Frequency Load Shedding Assessment;
- ✓ Through the SS-38 Working Group:
  - consider the development of a uniform approach, as requested by TFSP, for identifying BES Elements that meet one or more of the Criteria in R1 of PRC-026-1;
  - Continue to instigate the use of dynamic load models for transient stability studies; and,
  - Work with the NERC Load Modeling Task Force to ensure consistency in load modeling and to share best practices.

TFSS Reliability Assessment and Performance Analysis 2018 Goals and Deliverables

- ✓ Participate in the development and submission of NPCC comments/inputs into the development of regional and/or continent-wide reliability standards that address the NERC Reliability Standards.
- ✓ Provide support and technical input, for Task Force related BES risks as identified by the NERC Reliability Issues Steering Committee (RISC);
- ✓ Review existing Regional Criteria and procedures for validation of data used in power flow and dynamic simulations and if the existing criteria or procedures are found to be deficient, propose changes to provide for adequate data validation.
- ✓ Through the SS-38 Working Group:
  - Coordinate management of governor models used in NPCC studies;
  - support the performance of event replication by benchmarking against actual system performance;
  - review and develop comment on draft NERC standards; and,
  - Work with software vendors and NERC systems Analysis and Modeling subcommittee (SAMS) to enhance the capability for dynamic simulations.

Task Force on System Protection

The purpose of the NPCC Task Force on System Protection (TFSP) is to promote the reliable and efficient operation of the interconnected bulk power systems in Northeastern North America through the establishment of directories, criteria, guidelines, and procedures and coordination of design, relative to the protection associated with the bulk power systems. In addition, the TFSP provides technical support regarding operating expertise to the NPCC Regional Standards Committee and the NPCC Compliance Committee, and provides support and technical input for related BES risks identified by the NERC Reliability Issues Steering Committee (RISC) and the NERC Essential Reliability Services Working Group.

The Task Force on System Protection activities indicated below are done in support of ERO Goal No. 3 "*Identification and Assessment of Significant Risks to Reliability*" and ERO Goal No. 4 "I*dentification and Assessment of Emerging Risks to Reliability*." A related contributing activity to ERO Goal No. 3 is to "Engage industry, forums, and technical committees in identifying and mitigating risks, including reducing misoperations, AC equipment failures, vegetation-related outages, and improving cold weather preparedness and human performance." A related contributing activity to ERO Goal No. 4 is to "Evaluate the reliability impacts of distributed energy resources on planning, operations and restoration and recovery, including the identification of data and information sharing needs."

TFSP Reliability Assessment and Performance Analysis 2018 Goals and Deliverables

- ✓ Assess proposed protection systems and special protection systems for compliance with Directory No. 4 and Directory No. 7;
- ✓ Participate or serve as lead Task Force in the implementation of applicable Regional NERC Reliability Standards;
- ✓ Review and respond to Questions, Requests for Interpretations and/or Clarifications related to bulk power system protection requirements in NPCC Directories and Criteria, as needed;
- ✓ Through the SP-7 Working Group, review misoperations of protection systems and Remedial Action Schemes/Special Protection Systems as they occur in the NPCC Region and participate in providing the NPCC input for the NERC Section 1600 Data Request.
- ✓ Review mitigations and/or progress reports for BPS Risk Reduction Implementation at each meeting and annually report to the RCC on the status of this implementation; and,
- ✓ Provide support and technical input for Task Force related BES risks as identified by the NERC Reliability Issues Steering Committee "RISC". Conduct a thorough review, provide comments as necessary and act on posted materials as directed. Task Force assessments and recommendations will be forwarded to the RCC for approval and submittal to NERC via NPCC Staff and the NERC Risk Control Process.

TFSP Reliability Assessment and Performance Analysis 2018 Goals and Deliverables

- ✓ Conduct review/development of the following Documents:
  - Directory No. 7 – "*NPCC Special Protection Systems*." Serve as the lead Task Force working in conjunction with the TFCP and the TFSS on revisions to ensure consistency with the development of the PRC-01202 NERC standard on Remedial Action Schemes.
  - Through the SP-9 Working Group on Telecommunication Circuits Used For Teleprotection and Remidial Action Schemes, develop a new guideline for tele-protection communication reliability.
- ✓ Participate in the ongoing development and submission of NPCC inputs/comments into the development of bulk electric system protection related NERC Reliability Standards;
- ✓ Through the SP-7 Working Group, maintain ongoing log of protection relay failures. Coordinate improved data gathering of relay failures among equipment owners, manufacturers, and vendors;
- ✓ Review and analyze the performance of protection systems of power system disturbances, lessons learned, and events inside as well as outside NPCC as brought to the attention of TFSP by the SP-7 Working Group, NERC Event Analysis Coordinating Group or as requested by the RCC. Issue recommendations for changes to NPCC Documents and lessons learned, as appropriate; and,

- ✓ Support NERC's effort through the ERO-RAPA group to continue relay misoperations performance analysis to reduce protection system misoperations and inform the RCC on relay misoperations trends, and share good practices.

TFSP Reliability Assessment and Performance Analysis 2018 Goals and Deliverables

- ✓ Consistent with the TFSP's scope, conduct joint meeting with other Regions to share best practices and experiences.

Task Force on Coordination of Operation

The NPCC Task Force on Coordination of Operation (TFCO) facilitates the coordination of operations among the NPCC Reliability Coordinator areas and adjacent NERC Regions to enhance the reliability of the bulk power system. In addition, the TFCO provides technical support regarding operating expertise to the NPCC Regional Standards Committee and the NPCC Compliance Committee, and provides support and technical input for related BES risks identified by the NERC Reliability Issues Steering Committee (RISC) and the NERC Essential Reliability Services Working Group.

The Task Force on Coordination of Operation activities indicated below are done in support of ERO Goal No. 3 "*Identification and Assessment of Significant Risks to Reliability*" and ERO Goal No. 4 "*Identification and Assessment of Emerging Risks to Reliability.*" Related contributing activities related to ERO Goal No.3 include "Conduct assessments of system resiliency and develop guidance for operations in a more secure state;" and ERO Goal No.4 "Evaluate the reliability impacts of distributed energy resources on planning, operations and restoration and recovery, including the identification of data and information sharing needs."

TFCO Reliability Assessment and Performance Analysis 2018 Goals and Deliverables

- ✓ Prepare and conduct the spring and autumn NPCC System Operator Seminars. Provide recommendations to enhance the programs;
- ✓ Develop and securely disseminate the annual compilation of "Facilities for Notification";
- ✓ Support and take part in a biennial, continent-wide Grid Security Exercise (GridEx), including a review of the associated reports and Lessons Learned;
- ✓ Support an annual enhanced, wide area restoration drill among the Reliability Coordinator areas of NPCC and their neighboring Reliability Coordinators incorporating the annual review of the NPCC regional restoration plan;
- ✓ Conduct pre-seasonal NPCC Reliability Assessments incorporating multi-area probabilistic reliability simulation results in each assessment. Coordinate the NPCC input for the annual data for seasonal short-term NERC Reliability Assessments;
- ✓ Conduct reviews of applicable NPCC Directories, Criteria, Guides and Procedures in accordance with their applicable review dates;
- ✓ Coordinate system awareness among NPCC RCs through periodic conference calls. This includes the existing emergency preparedness, NPCC weekly and daily system operator conference calls; and,
- ✓ Monitor the trends and impacts of the changing resource mix and the effects of the proliferation of the new resources on real-time operations, particularly the measures identified in the Essential Reliability Services Framework Report, as well as behavior during and impacts on recovery and restoration plans including consideration of distributed resources, considering the variable and energy-limited nature of the resource shifts.

TFCO Reliability Assessment and Performance Analysis 2018 Goals and Deliverables

- ✓ Review a biennial summary of operating tool failures and lessons learned for the preceding study period;
- ✓ Provide assistance to the NERC Event Analysis process (EAP). Evaluate the operational applicability of Lessons Learned from the NERC EAP; and,
- ✓ Keep informed of the NERC Operating Committee and other subcommittee activities to determine their impact on the NPCC and any potential adjustments to Criteria, as well as provide feedback and input to the respective committees.

TFCO Reliability Assessment and Performance Analysis 2018 Goals and Deliverables

- ✓ Review and analyze the performance of Simultaneous Activation of Reserve (SAR) implementation following an event to enhance the SAR process; and,
- ✓ Share lessons learned among training staff from the NPCC RCs and utilize to make training program enhancements.

NPCC Regulatory/Governmental Affairs Advisory Group

The purpose of the NPCC Regulatory/Governmental Affairs Advisory Group is to promote NPCC interaction and coordination with Federal/State/Provincial governmental and/or regulatory agencies on a coordinated Regional basis, and identify and develop policy input for NPCC and Northeast Regional governmental and/or regulatory bodies.

The NPCC Governmental/Regulatory Affairs Advisory Group provides a forum where industry and governmental and/or regulatory representatives can exchange views and strive to develop consensus policy recommendations on reliability issues specific to the NPCC Region (Northeastern United States and Eastern Canada) and share actionable information among NPCC, NERC and other related governmental and/or regulatory agencies related to Regional energy and reliability matters.

The Regulatory/Governmental Affairs Advisory Group activities indicated below are done in support of ERO Goal No. 4 “Identification and Assessment of Emerging Risks to Reliability.” A related contributing activity to this Goal is to “Educate policy makers, regulators, and the industry of reliability effects and interconnection requirements for the changing resource mix.”

NPCC Regulatory/Governmental Affairs Advisory Group 2018 Goals and Deliverables

- ✓ Continued outreach to NPCC’s state electricity and environmental regulators stressing the importance of understanding and considering reliability impacts during the development of State/Provincial initiatives (such as the identified Essential Reliability Services). This includes focus on initiatives concerning regional planning, distributed energy resource requirements, the timing of new generation resources and transmission infrastructure projects.

Based on the portion of professional/technical staff time and other resources devoted to Reliability Assessment and Performance Analysis, NPCC estimates that it will expend 22% of its resources on these activities.

Resource Requirements

Personnel

- NPCC anticipates no need to hire additional personnel in this program area in 2018.

Reliability Assessment and Performance Analysis Program

Funding sources and related expenses for the Reliability Assessment and Performance Analysis section of the 2018 business plan are shown in the table below. Explanations of variances by expense category are included with the Supplemental Tables found in Section B.

Statement of Activities and Capital Expenditures
2017 Budget & Projection, and 2018 Budget
Reliability Assessment and Performance Analysis

		2017 Budget	2017 Projection	Variance 2017 Projection v 2017 Budget Over(Under)	2018 Budget	Variance 2018 Budget v 2017 Budget Over(Under)
Funding						
ERO Funding						
	ERO Assessments	$ 3,206,966	$ 3,206,966	$ -	$ 3,225,570	$ 18,604
	Penalty Sanctions	-	-	-	15,151	15,151
Total ERO Funding		**$ 3,206,966**	**$ 3,206,966**	**$ -**	**$ 3,240,721**	**$ 33,755**
	Membership Dues	-	-	-	-	-
	Testing Fees	-	-	-	-	-
	Services & Software	-	-	-	-	-
	Workshops	-	-	-	-	-
	Interest	-	-	-	-	-
	Miscellaneous	-	-	-	-	-
Total Funding (A)		**$ 3,206,966**	**$ 3,206,966**	**$ -**	**$ 3,240,721**	**$ 33,755**
Expenses						
Personnel Expenses						
	Salaries	$ 1,084,994	$ 1,084,994	$ -	$ 1,106,772	$ 21,778
	Payroll Taxes	65,373	65,373	-	65,805	432
	Benefits	214,688	214,688	-	220,007	5,319
	Retirement Costs	121,271	121,271	-	117,144	(4,127)
Total Personnel Expenses		**$ 1,486,325**	**$ 1,486,325**	**$ -**	**$ 1,509,728**	**$ 23,402**
Meeting Expenses						
	Meetings	$ 20,500	$ 20,500	$ -	$ 22,000	$ 1,500
	Travel	186,850	186,850	-	212,000	25,150
	Conference Calls	-	-	-	-	-
Total Meeting Expenses		**$ 207,350**	**$ 207,350**	**$ -**	**$ 234,000**	**$ 26,650**
Operating Expenses						
	Consultants & Contracts	$ 413,000	$ 413,000	$ -	$ 401,640	$ (11,360)
	Office Rent	-	-	-	-	-
	Office Costs	-	-	-	-	-
	Professional Services	-	-	-	-	-
	Computer & Equipment Leases	-	-	-	-	-
	Miscellaneous	-	-	-	-	-
	Depreciation	-	-	-	-	-
Total Operating Expenses		**$ 413,000**	**$ 413,000**	**$ -**	**$ 401,640**	**$ (11,360)**
	Total Direct Expenses	**$ 2,106,675**	**$ 2,106,675**	**$ -**	**$ 2,145,368**	**$ 38,692**
Indirect Expenses		**$ 1,125,541**	**$ 1,125,541**	**$ -**	**$ 1,134,543**	**$ 9,002**
Other Non-Operating Expenses		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)		**$ 3,232,217**	**$ 3,232,217**	**$ -**	**$ 3,279,911**	**$ 47,694**
Change in Assets		**$ (25,251)**	**$ (25,251)**	**$ -**	**$ (39,190)**	**$ (13,939)**
Fixed Assets						
	Depreciation	$ -	-	$ -	$ -	$ -
	Computer & Software CapEx	-	-	-	-	-
	Furniture & Fixtures CapEx	-	-	-	-	-
	Equipment CapEx	-	-	-	-	-
	Leasehold Improvements	-	-	-	-	-
	Allocation of Fixed Assets	(25,251)	(25,251)	-	(39,190)	(13,939)
Inc(Dec) in Fixed Assets (C)		**(25,251)**	**(25,251)**	**-**	**(39,190)**	**(13,939)**
TOTAL BUDGET (=B+C)		3,206,966	3,206,966	-	3,240,721	33,755
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)		**$ 0**	**$ 0**	**$ -**	**$ 0**	**$ (0)**

Training, Education, and Operator Certification Program

Training, Education, and Operator Certification Program Resources (in whole dollars)	2017 Budget	2018 Budget	Increase (Decrease)
Total FTEs	0.10	0.10	0.00
Direct Expenses	$229,785	$230,263	$477
Indirect Expenses	$19,306	$19,460	$154
Other Non-Operating Expenses	$0	$0	$0
Inc(Dec) in Fixed Assets	($433)	($672)	($239)
Total Funding Requirement	$248,658	$249,051	$393

Program Scope and Functional Description

The NPCC Training, Education, and Operator Certification program supports NERC Rules of Procedure Section 900. The program provides education and training necessary to understand and operate the bulk electric system. The target audience of the program is bulk power system operating personnel - including system operations personnel, operations support personnel (engineering and information technology), supervisors and managers, and training personnel. NPCC staff training and development is incorporated within each respective program area.

Training Program Background and Description

This NPCC Program establishes and coordinates training for system operators relating to inter-Reliability Coordinator area matters, criteria, terminology, standards and operating procedures and instructions. It includes development and execution of training seminars, held twice yearly, at which: 1) potential operational problems for the coming season are discussed, 2) application of NPCC Directory and NERC Standard requirements pertinent to operation are discussed, 3) major industry issues that are important for system operators are discussed, 4) significant disturbances are reviewed for lessons learned and 5) table-top drills and communication and coordination exercises are conducted. The seminars promote camaraderie and better communication among system operators from the NPCC Reliability Coordinator (RC) areas and the Nova Scotia Balancing Authority (BA) area.

This Program also provides for: 1) sharing of RC/BA existing training program and system simulator area content; 2) training techniques and methods; 3, 3) evaluation of new techniques and training and simulator aids as they become available; 4) opportunities to consolidate training among the NPCC RCs and BAs, which includes opportunities to share training material and training sessions; and 5) exchange of information on internal methods of system operator training.

The training activities indicated below are done in support of ERO Goal No. 5 “Effective and Efficient ERO Enterprise Operations.”. A related contributing activity to this goal is to “Acquire, engage, develop, and retain highly qualified talent with requisite technical expertise to execute the ERO Enterprise’s statutory functions.”

Funding Drivers and Reliability Benefits

- Provide two high-quality continuing education seminars for system operators;
    - System operators participating in the Seminars: 1) share their approaches to solving operational problems and learn about the characteristics of neighboring systems; 2) gain exposure to NPCC issues and current industry operational topics; 3) review recent NPCC and major external disturbances; 4) review key operational related content in NPCC Directories and NERC Standards; and 5) participate in hands-on "table top exercises" pertaining to system operational practices. PJM system operators and trainers are also invited to participate and normally attend these seminars;
    - Seminar attendees also receive Continuing Education Hours (CEHs) (normally 3.5 to 4 CEHs) and operator trainers from each RC / BA area can utilize the seminar content by including it in their internal training programs to provide CEHs to all system operators; and,
    - The seminars help to improve system operational coordination through better contact among system operators at other Reliability Coordinator areas.
- Continually review and revise the curriculum of the training seminars to better emphasize NERC Standard requirements related to system operation, NPCC wide-area operations and Regionally-specific criteria and procedures;
- Enhance the system operator's awareness and knowledge of the standards, criteria and procedures they apply in real time operation;
- Provide more sharing of new training approaches, exchange of information on internal methods of system operator selection, training material and training sessions:
    - Enhance efficiency and cost savings in the training programs in the NPCC RC / BA areas;
- Provide a forum among NPCC RC/BA areas for sharing of approaches to meet the requirements of the NERC PER standards. The sharing of approaches used by some NPCC Areas to address any changes needed to existing system operator training programs due to PER-005-2 requirements is valuable to CO-2 Working Group members.
- Implement changes needed for the NPCC Reliability Coordinator / Balancing Authority Areas to meet proposed expanded training requirement for operations support staff in PER-005-2; and,
- NPCC will conduct two Standards and Compliance workshops in 2018, for NPCC Stakeholders, for the express purpose of providing the most current and applicable information related to the development of NERC and Regional Reliability Standards and the implementation of the Compliance Monitoring and Enforcement Program (CMEP).

2018 Key Assumptions

NPCC regularly conducts seminars as well as Spring and Fall Standards and Compliance workshops specifically designed, primarily through the conduct of targeted breakout class room sessions and presentations on current industry related activities, to provide for the most efficient exchange of information between the NPCC Compliance and Standards staff and the NPCC Stakeholders. Presentations in the past have been conducted by FERC, NERC and Stakeholder representatives in addition to NPCC staff members. To supplement these workshops, NPCC is considering developing on-line webinars that will focus on a specific topic pertinent to developments related to compliance program implementation, standards development or technical issues.

NPCC also regularly conducts Spring and Fall System Operator Seminars. These seminars involve system operators from the NPCC RC/BA Areas and PJM, and are held in early May and early November.

Training, Education and Operator Certification 2018 Goals and Deliverables

- Prepare and conduct the 2018 Spring and Fall NPCC System Operator Seminars;
- Implement the PER-005-2 expanded requirements within the NPCC RC/BA Area programs; and,
- Continue collaboration and sharing of the intended RC/BA approaches, experiences and materials to task identification and training development associated with NERC Standard PER-005-2.

Training, Education and Operator Certification 2018 Goals and Deliverables

- As needed, expand the NPCC repository of training resources and learning verification activities addressing fundamental power system topics, training methods and operation procedure training exercises, which may be shared as elements of operator training in compliance with NERC Standard PER-005, "*System Personnel Training*"; and,

Develop on-line operational training webinars that focus on specific topics pertinent to related to compliance program implementation, standards development or technical issues.
Based on the portion of professional/technical staff time and other resources devoted to training, education, and operator certification, NPCC estimates that it will expend 2% of its resources on this activity.

Resource Requirements

Personnel

- NPCC anticipates no need to hire additional personnel in this program area in 2018.

Training, Education, and Operator Certification Program

Funding sources and related expenses for the training, education, and operator certification section of the 2018 business plan are shown in the table below. Explanations of variances by expense category are included with the Supplemental Tables found in Section B.

Statement of Activities and Capital Expenditures
2017 Budget & Projection, and 2018 Budget
Training, Education, and Operator Certification

	2017 Budget	2017 Projection	Variance 2017 Projection v 2017 Budget Over(Under)	2018 Budget	Variance 2018 Budget v 2017 Budget Over(Under)
Funding					
ERO Funding					
ERO Assessments	$ 184,658	$ 184,658	$ -	$ 184,791	$ 133
Penalty Sanctions	-	-	-	260	260
Total ERO Funding	**$ 184,658**	**$ 184,658**	**$ -**	**$ 185,051**	**$ 393**
Membership Dues	-	-	-	-	-
Testing Fees	-	-	-	-	-
Services & Software	-	-	-	-	-
Workshops	64,000	64,000	-	64,000	-
Interest	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Total Funding (A)	**$ 248,658**	**$ 248,658**	**$ -**	**$ 249,051**	**$ 393**
Expenses					
Personnel Expenses					
Salaries	$ 21,012	$ 21,012	$ -	$ 18,399	$ (2,613)
Payroll Taxes	1,396	1,396	-	1,350	(46)
Benefits	4,801	4,801	-	4,893	92
Retirement Costs	2,641	2,641	-	2,320	(321)
Total Personnel Expenses	**$ 29,850**	**$ 29,850**	**$ -**	**$ 26,963**	**$ (2,888)**
Meeting Expenses					
Meetings	$ 186,300	$ 186,300	$ -	$ 188,300	$ 2,000
Travel	13,635	13,635	-	15,000	1,365
Conference Calls	-	-	-	-	-
Total Meeting Expenses	**$ 199,935**	**$ 199,935**	**$ -**	**$ 203,300**	**$ 3,365**
Operating Expenses					
Consultants & Contracts	$ -	$ -	$ -	$ -	$ -
Office Rent	-	-	-	-	-
Office Costs	-	-	-	-	-
Professional Services	-	-	-	-	-
Computer & Equipment Leases	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Depreciation	-	-	-	-	-
Total Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Direct Expenses	**$ 229,785**	**$ 229,785**	**$ -**	**$ 230,263**	**$ 477**
Indirect Expenses	**$ 19,306**	**$ 19,306**	**$ -**	**$ 19,460**	**$ 154**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)	**$ 249,091**	**$ 249,091**	**$ -**	**$ 249,723**	**$ 632**
Change in Assets	**$ (433)**	**$ (433)**	**$ -**	**$ (672)**	**$ (239)**
Fixed Assets					
Depreciation	$ -	-	$ -	$ -	$ -
Computer & Software CapEx	-	-	-	-	-
Furniture & Fixtures CapEx	-	-	-	-	-
Equipment CapEx	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-
Allocation of Fixed Assets	(433)	(433)	-	(672)	(239)
Inc(Dec) in Fixed Assets (C)	**(433)**	**(433)**	**-**	**(672)**	**(239)**
TOTAL BUDGET (=B+C)	248,658	248,658	-	249,051	393
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)	**$ (0)**	**$ (0)**	**$ -**	**$ 0**	**$ 0**

Situation Awareness and Infrastructure Security Program

Situation Awareness and Infrastructure Security Program Resources (in whole dollars)	2017 Budget	2018 Budget	Increase (Decrease)
Total FTEs	4.00	5.00	1.00
Direct Expenses	$1,188,137	$1,373,791	$185,654
Indirect Expenses	$772,241	$973,021	$200,780
Other Non-Operating Expenses	$0	$0	$0
Inc(Dec) in Fixed Assets	($17,325)	($33,611)	($16,286)
Total Funding Requirement	$1,943,053	$2,313,202	$370,148

Program Scope and Functional Description

The Situation Awareness and Infrastructure Security Program is the combination of near real time awareness of conditions on the bulk power system with the programs necessary to increase the physical and cyber security of the electricity infrastructure, including the operation and maintenance of tools and other support services for the benefit of Reliability Coordinators and the system operators within the registered entities. Maintaining the real-time awareness of conditions on the interconnected bulk power systems by the NPCC Reliability Coordinator is critical to maintaining reliable operation within NPCC, including the communication of information concerning system conditions and abnormal events among the neighboring system operators responsible for the reliable operation of the bulk power systems. When a disturbance does occur, it is critical to use the event as a learning opportunity and provide a forum for the active coordination of reliability and operation among the NPCC Reliability Coordinator areas and neighboring NERC Regions to enhance the reliability of the interconnected bulk power system through the lessons to be learned which can be gleaned from such an event.

These Situation Awareness and Infrastructure Security activities indicated below are done in support of ERO Goal No. 3 "*Identification and Mitigation of Significant Risks to Reliability*." A related contributing activity to this Goal is to "Analyze system performance, events, and relationships among data sources to identify risks and mitigation strategies, and provide recommendations and lessons learned."

Event Analysis Program Description

NERC and the industry follow three avenues in the analysis of a disturbance: the identification of lessons to be learned, a formal cause code analysis and a review of applicable standards.

The Event Analysis Program recognizes that many events which occur on the bulk power system beyond those identified through NERC Reliability Standard EOP-004-2, "Event Reporting," can have varying levels of significance to the electric system, providing otherwise unrealized lessons to be learned from these events and the trending of such events to identify possible reliability concerns. By integrating a "bottom-up" approach to a disturbance review within the framework of the NERC Event Analysis Program, consistency, comparability, flexibility and timeliness in the event analysis process will be promoted by NPCC, the registered entities and NERC in a collaborative initiative. Upon the identification of an event, the goal of the Event Analysis Program is to:

- identify what transpired;
- categorize the event within the NERC Event Analysis Program;
- establish the sequence of events;
- understand the essential root causes of the event;
- identify recommendations or corrective actions; and,
- develop and disseminate to the industry lessons to be learned so that the operational reliability of the bulk power system can be further enhanced.

In assessing any system event, it is recognized that, if the timely dissemination of lessons learned from an event or disturbance is to be realized, any potential compliance implications associated with an event must be addressed and dismissed. Throughout an event analysis effort, to make this process successful and complete, and to solidify the "bottom-up" approach, registered entities are encouraged to establish a liaison between the event analysis and compliance functions internal to the registered entity during the event analysis process. This serves to facilitate the development of a registered entity compliance self-assessment report which will perform a sufficiency review of the reliability standards deemed applicable to the event, assisting in the self-reporting of possible violations should any be discovered.

To complete this effort, the entity, the Region and NERC staff will collaborate to assess the NERC Event Analysis Report and perform a formal cause code analysis, identifying a root cause and publish any pertinent lessons learned gathered from the disturbance.

The adoption by NERC of the Event Analysis Program brings clarity and certainty about what system events are relevant to analyze and to what level of detail, targeting potential risks to the reliability of the bulk power system for detailed and in depth analysis; only concise and succinct reviews are desired for more minor events. It also delineates the expectations of roles and responsibilities of the registered entities, NPCC and NERC in a uniform review of system disturbances by the industry, and, ultimately, the program promotes the timely development and dissemination of valuable lessons learned to the industry. The identification and tracking of emerging common risks through the assessment of events will further distinguish trends which may be of concern to reliability. By rigorously pursuing the lesser events on the system and learning from these disturbances, larger events can be avoided or mitigated.

NPCC staff works step-by-step with the registered entity in the total event analysis process, permitting the entity to assume the primary role in the development of the initial analysis, lessons learned which may benefit the industry and the Standards sufficiency review and cause coding for trending and reporting. NPCC staff, throughout the process, guides, supports and stands as an advocate of the registered entity as they continue to develop an improved culture of reliability and compliance.

2018 Key Assumptions

- The monitoring of Lessons Learned will continue to be a major focus of NERC in 2018. This will include an added aspect of the voluntary Event Analysis Program, in response to a recommendation of the AC Substation Equipment Task Force (ACSETF), to solicit and collect detailed information on station equipment failures, for applicable, qualifying events to aid in future analysis of station equipment failures to identify trends that may be a threat to the reliability of the BES;
- Critical infrastructure protection will fully integrate the requirements of Version 5 of the Cyber Standards in 2018; and,

- NERC will post updates to the critical infrastructure protection (CIP) Standards to address the three FERC Directives and the four industry concerns that were not satisfactorily responded to by the version 5 Transition Advisory Group.

Situation Awareness 2018 Goals and Deliverables

NERC Activities

- NPCC will provide the Regional perspective and support through NPCC EA staff participation on selective NERC Planning and Operating Committees and key related NERC Subcommittees, Task Forces and Working Groups, including:
  Event Analysis Subcommittee (EAS);
  ERO – EA/SA Group; and,
  The Event Analysis Management System (TEAMS).

NPCC Activities

- Work directly with applicable NPCC Task Forces to provide an in-depth assessment of Lessons Learned unique to the NPCC members and NPCC Criteria;
- Promote NPCC's Event Analysis group's established process for sharing and dissemination of the detailed Event Analysis Report information among industry participants (registered entities);
- Incorporating the Lessons Learned from participation in the GridEx IV wide-area exercise;
- Utilize the NPCC's "what if" methodology to examine an event's potential impact under a different set of system conditions, to evaluate the proximity of a particular event to being a significant BPS requiring appropriate level of analysis with due weight to risk and impact;
- Establish a process/procedure for data capture and transfer aspects for post-disturbance (major disturbance and/or blackout events) system analysis, including requirements for regularly scheduled (annual) testing of the procedure implementation;
- Monitor the operational status of the bulk power system and coordinate normal and pre-emergency communication, awareness and assistance in addition to the same during an emergency among the Reliability Coordinators (RCs) within NPCC. Notify the RCs of significant bulk power system events that have occurred in one Reliability Coordinator Area, and which have the potential to impact reliability in other NPCC Reliability Coordinator Areas or Regions external to NPCC. These events include contingencies on the bulk power system, potential shortfalls of operating reserve, operating problems, potential security threats and potential threats or disruptions to the cyber systems;
- Conduct a daily conference call to serve as a complement to the NPCC Emergency Preparedness Conference Call. The participants of the call are the Reliability Coordinators within NPCC and its neighboring RCs, the Midcontinent ISO and PJM. The conference call is implemented through a bridge, the initiation of the call quickly ringing all pre-selected telephones simultaneously. The goal of the call is to alert all Reliability Coordinators of emerging problems. If no system difficulties are anticipated for the day, no unnecessary information is to be discussed. Subjects for discussion are limited to credible events which could impact the ability of an entity to serve its load and meet its operating reserve obligations or would impose a burden to the interconnection, including the following: Projected Load; Adverse Weather; Operating Reserve; Generation; Transmission; and Sabotage. If conditions worsen in the course of the day, the NPCC Emergency Preparedness Conference Call will be implemented;
- Monthly test of the satellite telephone network, to ensure the capability for continued voice communications among NPCC and its Reliability Coordinators. This back-up communications system will function in the event of a collapse of the Public Switched

Telephone Network (PSTN), permitting continued cross-border voice communications among the Canadian Reliability Coordinators of NPCC, the Reliability Coordinators in the United States as well as NPCC Situation Awareness (SA) staff.

Situation Awareness 2018 Goals and Deliverables

Monitor the status of the bulk power system through the NERC Situational Awareness-FERC, NERC, Regions (SAFNR) initiative, a near real-time operating display for the United States portion of the Reliability Coordinators footprints of North America. Transmission voltage levels of 230 kV and above are displayed, and the tool provides the ability to "drill down" to detailed bus information, including generation outputs and bus voltages.

Critical Infrastructure Objectives

NPCC's critical infrastructure objectives are defined within the scope of the NPCC Task Force on Infrastructure Security & Technology, (TFIST) and include, but are not confined to:

- Providing a forum for NPCC review of proposed and posted documents from the NERC Critical Infrastructure Protection Committee (CIPC); and,
- Representing and advocating NPCC's position in the activities of NERC groups involved in the development and/or implementation of physical and cyber security.

NPCC's 2018 critical infrastructure goals and objectives, supporting ERO Goal No. 3 - *Identification and Mitigation of Significant Risks to Reliability*." Related contributing activities to this Goal include "Expand the use, availability, and value of physical security and cybersecurity threat and vulnerability information sharing, including cross sector communications, and analytics" and "In collaboration with the Critical Infrastructure Protection Committee and industry stakeholders, develop a risk process to address the potential impact of cyber and physical security threats and vulnerabilities."

Critical Infrastructure 2018 Goals and Deliverables

- Monitor the reliable implementation of the Cyber Security Standards;
- Monitor the Homeland Security Information Network (HSIN), E- ISAC, NERC Alerts and Canadian Information Sharing and share information with the NPCC CO-8 Working Group;
- Review and submit comments on NERC proposed Reliability Standards, modified Reliability Standards, proposed Guidelines and modified Guidelines related to Infrastructure Security and Technology;
- Keep current on all governmental agencies regarding applicable security recommendations and requirements, and other applicable security and reliability recommendations and keep the RCC and its committees appropriately informed, e.g. Sector Specific Plan;
- Conduct an annual test of cross border emergency telecommunications to verify each Area can communicate with each other;
- Provide support and technical input for Task Force related BES risks as identified by the NERC Reliability Issues Steering Committee "RISC." The Task Force will conduct a thorough review, provide comments as necessary and act on posted materials as directed; and,
- Support the NERC CIPC Grid Exercise Working Group (GEWG) with Cross Sector support in Grid Exercise (GridEx) IV planning and simulation. Participate in the development of lessons learned from GridEx IV.

Critical Infrastructure 2018 Goals and Deliverables

- Review infrastructure security & technologies and provide recommendations to enhance physical and cyber security in compliance with NERC guidelines/standards;
- Provide recommendations to enhance physical and cyber security, in compliance with NERC standards, based on assessments of available and emerging infrastructure security technologies, methodologies, and best practices;
- Sponsor periodic workshop presentations to address timely issues and update NPCC Members associated with infrastructure security and technology.; and,
- Provide education, awareness, and support for Cross Sector coordination in Entity agreements and response plans with focus upon Telecommunications, Water and Natural Gas, including monitoring and sharing with the E-ISAC.

Related System Operations Security 2018 Goals and Deliverables

NPCC's system operations security objectives are defined within the scope of the NPCC Task Force on Coordination of Operation (TFCO) and include, but are not confined to:

- Coordinating inter-Regional pre-emergency actions in the event of a threat to the security of the Northeastern North American bulk power supply system; and,
- Assisting in the development of real time operating tools assuring cyber security concerns are addressed.

2018.Based on the portion of professional/technical staff time and other resources devoted to situation awareness and infrastructure security, NPCC estimates that it will expend 16% of its resources on this activity.

Resource Requirements

Personnel

- Reallocation of staff during 2017 resulted in an increase of one full time employee in the Situation Awareness and Infrastructure Security program to support increased workload in this area.

Consultants and contracts

- Decrease in consulting and contracts expense is associated with increase in staff allocated to this program area.

Situation Awareness and Infrastructure Security Program

Funding sources and related expenses for the situation awareness and infrastructure security section of the 2018 business plan are shown in the table below. Explanations of variances by expense category are included with the Supplemental Tables found in Section B.

Statement of Activities and Capital Expenditures
2017 Budget & Projection, and 2018 Budget
Situation Awareness and Infrastructure Security

	2017 Budget	2017 Projection	Variance 2017 Projection v 2017 Budget Over(Under)	2018 Budget	Variance 2018 Budget v 2017 Budget Over(Under)
Funding					
ERO Funding					
ERO Assessments	$ 1,943,053	$ 1,943,053	$ -	$ 2,300,208	$ 357,155
Penalty Sanctions	-	-	-	12,994	12,994
Total ERO Funding	**$ 1,943,053**	**$ 1,943,053**	**$ -**	**$ 2,313,202**	**$ 370,148**
Membership Dues	-	-	-	-	-
Testing Fees	-	-	-	-	-
Services & Software	-	-	-	-	-
Workshops	-	-	-	-	-
Interest	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Total Funding (A)	**$ 1,943,053**	**$ 1,943,053**	**$ -**	**$ 2,313,202**	**$ 370,148**
Expenses					
Personnel Expenses					
Salaries	$ 660,213	$ 742,713	$ 82,500	$ 825,560	$ 165,347
Payroll Taxes	42,778	50,278	7,500	53,677	10,899
Benefits	160,814	173,564	12,750	189,417	28,603
Retirement Costs	72,333	83,583	11,250	87,637	15,304
Total Personnel Expenses	**$ 936,137**	**$ 1,050,137**	**$ 114,000**	**$ 1,156,291**	**$ 220,154**
Meeting Expenses					
Meetings	$ 13,500	$ 13,500	$ -	$ 10,000	$ (3,500)
Travel	78,500	85,250	6,750	87,500	9,000
Conference Calls	-	-	-	-	-
Total Meeting Expenses	**$ 92,000**	**$ 98,750**	**$ 6,750**	**$ 97,500**	**$ 5,500**
Operating Expenses					
Consultants & Contracts	$ 160,000	$ 160,000	$ -	$ 120,000	$ (40,000)
Office Rent	-	-	-	-	-
Office Costs	-	-	-	-	-
Professional Services	-	-	-	-	-
Computer & Equipment Leases	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Depreciation	-	-	-	-	-
Total Operating Expenses	**$ 160,000**	**$ 160,000**	**$ -**	**$ 120,000**	**$ (40,000)**
Total Direct Expenses	**$ 1,188,137**	**$ 1,188,137**	**$ 120,750**	**$ 1,373,791**	**$ 185,654**
Indirect Expenses	**$ 772,241**	**$ 772,241**	**$ -**	**$ 973,021**	**$ 200,780**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)	**$ 1,960,378**	**$ 1,960,378**	**$ 120,750**	**$ 2,346,812**	**$ 386,434**
Change in Assets	**$ (17,325)**	**$ (17,325)**	**$ (120,750)**	**$ (33,611)**	**$ (16,286)**
Fixed Assets					
Depreciation	$ -	-	$ -	$ -	$ -
Computer & Software CapEx	-	-	-	-	-
Furniture & Fixtures CapEx	-	-	-	-	-
Equipment CapEx	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-
Allocation of Fixed Assets	(17,325)	(17,325)	-	(33,611)	(16,286)
Inc(Dec) in Fixed Assets (C)	**(17,325)**	**(17,325)**	**-**	**(33,611)**	**(16,286)**
TOTAL BUDGET (=B+C)	1,943,053	1,943,053	120,750	2,313,202	370,148
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)	**$ (0)**	**$ (0)**	**$ (120,750)**	**$ 0**	**$ 0**

Administrative Services

Administrative Services Program Resources (in whole dollars)	Direct Expenses and Fixed Assets			FTEs		
	2017 Budget	2018 Budget	Increase (Decrease)	2017 Budget	2018 Budget	Increase (Decrease)
Technical Committees and Members Forum	$72,500	$70,680	($1,820)	0.50	0.50	0.00
General and Administrative	$3,245,691	$3,338,132	$92,441	2.50	2.50	0.00
Legal and Regulatory	$648,680	$592,049	($56,632)	1.00	1.00	0.00
Information Technology	$1,185,675	$1,119,490	($66,186)	2.00	2.00	0.00
Human Resources	$182,059	$181,145	($915)	1.00	1.00	0.00
Finance and Accounting	$525,262	$537,236	$11,974	1.00	1.00	0.00
Total Administrative Services	$5,859,868	$5,838,732	($21,136)	8.00	8.00	0.00

Program Scope and Functional Description

Administrative services support the previously identified five program areas of: reliability standards; compliance monitoring and enforcement and organization registration and certification; training, education, and operator certification; reliability assessment and performance analysis; and situation awareness and infrastructure security. Administrative services consist of: technical committees and members' forums; general and administrative; legal and regulatory; information technology; human resources; and finance and accounting.

Methodology for Allocation of Administrative Services Expenses to Programs

NPCC total overhead expenses, such as office rent and office costs, will be charged to the Administrative Services Programs and then reallocated proportionately based on FTE to the programs through Indirect Expenses.

Administrative Services

Funding sources and related expenses for the Administrative Services section of the 2018 business plan are shown in the table below. Explanations of variances by expense category are included with the Supplemental Tables found in Section B.

Statement of Activities and Capital Expenditures
2017 Budget & Projection, and 2018 Budget
ADMINISTRATIVE SERVICES

	2017 Budget	2017 Projection	Variance 2017 Projection v 2017 Budget Over(Under)	2018 Budget	Variance 2018 Budget v 2017 Budget Over(Under)
Funding					
ERO Funding					
ERO Assessments	$ (185,991)	$ (185,991)	$ -	$ 15,823	$ 201,813
Penalty Sanctions	-	-	-	-	-
Total ERO Funding	**$ (185,991)**	**$ (185,991)**	**$ -**	**$ 15,823**	**$ 201,813**
Membership Dues	-	-	-	-	-
Testing Fees	-	-	-	-	-
Services & Software	-	-	-	-	-
Workshops	-	-	-	-	-
Interest	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Total Funding (A)	**$ (185,991)**	**$ (185,991)**	**$ -**	**$ 15,823**	**$ 201,813**
Expenses					
Personnel Expenses					
Salaries	$ 1,872,579	$ 1,872,579	$ -	$ 2,063,139	$ 190,561
Payroll Taxes	93,995	93,995	-	97,378	3,383
Benefits	418,433	418,433	-	438,408	19,975
Retirement Costs	317,471	317,471	-	295,596	(21,874)
Total Personnel Expenses	**$ 2,702,478**	**$ 2,702,478**	**$ -**	**$ 2,894,522**	**$ 192,044**
Meeting Expenses					
Meetings	$ 120,000	$ 120,000	$ -	$ 116,750	$ (3,250)
Travel	143,590	143,590	-	138,000	(5,590)
Conference Calls	37,000	37,000	-	37,000	-
Total Meeting Expenses	**$ 300,590**	**$ 300,590**	**$ -**	**$ 291,750**	**$ (8,840)**
Operating Expenses					
Consultants & Contracts	$ 152,000	$ 152,000	$ -	$ 92,000	$ (60,000)
Office Rent	809,700	809,700	-	810,700	1,000
Office Costs	679,100	679,100	-	664,760	(14,340)
Professional Services	1,041,000	1,041,000	-	960,000	(81,000)
Computer & Equipment Leases	-	-	-	-	-
Miscellaneous	50,000	50,000	-	50,000	-
Depreciation	250,000	250,000	-	269,000	19,000
Total Operating Expenses	**$ 2,981,800**	**$ 2,981,800**	**$ -**	**$ 2,846,460**	**$ (135,340)**
Total Direct Expenses	**$ 5,984,868**	**$ 5,984,868**	**$ -**	**$ 6,032,732**	**$ 47,864**
Indirect Expenses	**$ (5,984,868)**	**$ (5,984,868)**	**$ -**	**$ (6,032,732)**	**$ (47,864)**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)	**$ -**	**$ -**	**$ -**	**$ 0**	**$ 0**
Change in Assets	**$ (185,991)**	**$ (185,991)**	**$ -**	**$ 15,823**	**$ 201,813**
Fixed Assets					
Depreciation	(250,000)	(250,000)	$ -	(269,000)	$ (19,000)
Computer & Software CapEx	125,000	125,000	-	75,000	(50,000)
Furniture & Fixtures CapEx	-	-	-	-	-
Equipment CapEx	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-
Allocation of Fixed Assets	125,000	125,000	-	194,000	69,000
Inc(Dec) in Fixed Assets (C)	**-**	**-**	**-**	**-**	**-**
TOTAL BUDGET (=B+C)	-	-	-	0	0
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)	**$ (185,991)**	**$ (185,991)**	**$ -**	**$ 15,823**	**$ 201,813**

Technical Committees and Member Forums

Program Scope and Functional Description

The success of the NPCC programs depends on the active and direct volunteerism and participation of its members. The stakeholders are the source of subject matter expertise in the industry. To promote the reliable and efficient operation of the interconnected bulk power systems in Northeastern North America, NPCC invites high level policy makers from Federal, Provincial and State regulatory and/or governmental authorities and senior executives within NPCC and NERC to identify and discuss emerging issues related to the reliability of the NPCC Region.

2018 Key Assumptions

- NPCC's standing committee and subgroup structure for effective stakeholder involvement will continue in 2018
- NPCC will continue to utilize methods to encourage active involvement in its Regional programs that require less stakeholder travel and face-to-face meetings, as the economy improves in 2018
- NPCC will continue to invest in technology and innovation to allow efficient collaboration on technical issues related to reliability

The Technical Committees and Member Forums activities indicated below are done in support of ERO Goal No. 4 "*Identification and Assessment of Emerging Risks to Reliability*." A related contributing activity to this Goal is to "Educate policy makers, regulators, and the industry of reliability effects and interconnection requirements for the changing resource mix."

Technical Committees and Member Forums 2018 Goals and Deliverables

- ✓ The 2018 NPCC General Meeting provides an opportunity for NPCC Members to meet high level policy makers from Federal, Provincial and State regulatory and/or governmental authorities and senior NERC and NPCC executives to discuss topics related to the reliable planning and operation of the power system, including consideration of emerging reliability, critical infrastructure and environmental issues; and,
- ✓ The objective of the NPCC Public Information Committee is to highlight and summarize NPCC activities and accomplishments in the past year, disseminate and coordinate the appropriate release of information to the media, respond to related requests for information, and coordinate with related NPCC Area, NERC media and public information activities. Activities anticipated include, but are not limited to:
    - Conducting the Media Event – release of the Summer 2018 NPCC Reliability Assessment; and,
    - Participation in NERC Regional communication initiatives:
        - Regional communications teleconferences as required
        - Coordination of Emergency or Blackout communications plans
        - Coordination with other NERC activities as required (i.e., situation awareness, event analysis, reliability assessments, etc.)

Resource Requirements

Personnel

- NPCC anticipates no need to hire additional personnel in this program area in 2018.

General and Administrative

Program Scope and Functional Description

The NPCC general and administrative function provides executive management of the corporation, management of NPCC office, and other administrative support programs.

NPCC total overhead expenses, such as office rent and office costs, will be charged to the Administrative Services Programs and then reallocated proportionately based on FTE to the programs through Indirect Expenses.

Resource Requirements

Personnel

- NPCC anticipates no need to hire additional personnel in this program area in 2018.

Office Rent

- Projected increase in real estate taxes.

Legal and Regulatory

Program Scope and Functional Description

NPCC's professional legal services provide counsel to the President and CEO, Board of Directors, Senior Vice President and COO, Treasurer, General Counsel and staff on a wide range of legal and regulatory matters including legislation, corporate law, code of conduct, confidentiality, governance, employment law, tax matters, contract law and other areas affecting NPCC. In support of ERO Goal 5.c., NPCC's in-house counsel evaluates internal controls and corporate, operational, strategic and reputational risk, and participates in risk identification, evaluation and mitigation activities. In-house counsel provides legal advice to advance significant corporate policy and strategic planning initiatives and also provide legal support to other program areas on matters arising in connection with the performance of NPCC's delegated functions. In-house counsel draft agreements and pleadings and provide interpretations of relevant statutes, regulations, court opinions, and regulatory decisions of FERC, state agencies and provincial authorities. Outside counsel, as necessary, reviews items filed with the governmental agencies for legal sufficiency, maintains relationships with U.S. and Canadian jurisdictions and provides contract review.

Resource Requirements

Personnel

- NPCC anticipates no need to hire additional personnel in this program area in 2018.

Professional Services

- Legal fees are projected to be lower based on additional workload taken on by in-house legal team.

Information Technology

Program Scope and Functional Description

NPCC's Information Technology services ensure information assets and the environment in which they operate are secure and in conformance to NPCC IT Policies and Procedures and all applicable Critical Electric Infrastructure Information protection and Confidentiality requirements. NPCC maintains an offsite backup server for continuity of essential operations in the event that its primary location is unavailable.

NPCC supports the ERO efforts to implement, operate and maintain software tools supporting common enterprise wide operations and leveraging ERO solutions which have been approved by the ERO Executive Management Group (ERO EMG), which is comprised of the senior leadership of NERC and each of the Regional Entities. NPCC's budget assumes the availability of enterprise software tools as described in NERC's business plan and budget. If implementation of these software applications is delayed or otherwise not available as planned, NPCC could incur additional costs to implement ERO Enterprise-wide programs pending the availability of these applications.

NERC and the Regional Entities are committed to working collaboratively to minimize duplication of effort and investments, and improve operational efficiency. This collaboration continues to refine existing strategies, governance and procurement practices applicable to the development, operation and maintenance of enterprise architecture, software and data systems supporting complementary and combined NERC and Regional Entity operations.

The NERC information technology budget does not supplant NPCC's need for IT expenditures for specific regional projects and internal region specific IT support needs. NPCC's 2018 Business Plan and Budget assumes agreed-upon ERO Enterprise applications will be available and includes only NPCC costs for region specific support needs.

2018 Key Assumptions

- Continue to maintain the compliance portal through collaboration with other Regional Entities and NERC (CUG).
- Support the Event Analysis program through continued participation in the tools used for the tracking and analysis of system events and identification of better practice elements.
- Support the Bulk Electric System Exception Process (BEP) to enable and facilitate tracking and processing of exceptions submitted. Maintenance of the BESNET support services such as updates, patching, coordinating issues with NERC.
- Support Cyber Security Reviews done by Compliance to provide advisory role during those reviews.

2018 Goals and Key Deliverables

Responsibilities encompass a variety of complex technical, administrative, and supervisory work in the development, installation, and maintenance of information technology systems. IT goals include, but are not limited to:

- Expand the utilization of the document management system throughout the company.
- Create an information security program and environment aimed at reducing breach of security risks
- Determine longer-term software and systems needs and hardware acquisitions
- Develop and implement information security standards and procedures

- Ensure all information systems are functional and secure, and that all applications running on those systems meet business requirements for performance, availability, and security
- Plan and implement organization-wide information systems, services, and network facilities, including local area networks, wide-area networks, and peripheral systems
- Provide outreach and education to NPCC members in IT best practices
- Continually improve Disaster Recovery and Business Continuity policies and practices to ensure continuity and reliability of IT and business related services

Resource Requirements

Personnel

- NPCC anticipates no need to hire additional personnel in this program area in 2018.

Human Resources

Program Scope and Functional Description

NPCC has assembled an exceptional team of highly qualified employees to carry out the activities of NPCC. The human resources function, in adherence with applicable federal and state laws, designs, plans, and implements human resources policies and procedures, including: staffing; compensation; benefits; employee relations; training and development; and employee time tracking.

Resource Requirements

Personnel

- Temporary office services increased to assist in administrative services in the area of human resources.

Accounting and Finance

Program Scope and Functional Description

The accounting and finance function directs the overall financial plans and accounting practices of the organization; oversees treasury, accounting, budget, tax, and audit activities; and oversees financial and accounting system controls and standards. NPCC uses a CPA firm to prepare its unaudited statements of activities and financial statements for quarterly reviews. Independent audits have identified this system as a best practice.

2018 Goals and Key Deliverables

The objectives are to provide or obtain the financial and accounting services for NPCC and coordinate with NERC requirements:

- Utilize the NERC System of Accounts for consistency
- Utilize an accrual method of accounting for consistency with NERC in methodology
- Alignment of changes in budget and changes in aggregate assessment
- Cash Management
- Budget Development using the NERC budget template formats
- Forecasts and Projections
- Alignment of NPCC Committees, Task Forces and Working Groups with the programs
- Payroll and expense administration
- Preparation of unaudited Quarterly Financial Variance Reports
- IRS Reporting
- Annual Independent Audit initiated by the Regional Entity

Resource Requirements

Personnel

- NPCC anticipates no need to hire additional personnel in this program area in 2018.

Regional Entity Assessment Analysis

In the area of assessments there are distinct funding mechanisms as outlined in the following table. For the Regional Entity division, the North American Electric Reliability Corporation (NERC) will assess load serving entities (LSEs) or their designees (within NPCC the designees are the Balancing Authority Areas (BAAs) for New York, New England, New Brunswick, Nova Scotia, Ontario and Québec) based upon 2016 proportional Net Energy for Load (NEL) and other specific program area funding arrangements and make quarterly remittances to the Regional Entity on or about the 15th day of January, April, July and October. For funding associated with the criteria services division, the Independent System Operators/Balancing Authority Areas (ISO/BAAs) will be assessed by NPCC for their proportional share of the divisional budget based upon 2016 NEL within the Region. Non ISO/BAA Full Members will be assessed no membership fee.

NPCC Cost Allocation Methodology

The accompanying table provides information regarding cost allocation for both the Regional Entity division and the criteria services division of NPCC, including the details associated with the funding of the Compliance Program within the RE division. For purposes of determining assessments to support NPCC's resource requirements, costs are allocated among the BAAs within NPCC as the designees for the load-serving-entities in New York, New England, Ontario, Québec, New Brunswick and Nova Scotia.

In order to reflect and respect the international membership and nature of NPCC, any sub-regional reliability assessment costs in response to U.S. only regulatory initiatives will be considered for allocation to U.S. only BAAs consistent with NERC Rules of Procedure section 1102. Additionally, the compliance responsibilities and authorities within the U.S., and the specific compliance responsibilities within each of the Canadian provinces within NPCC, and the attendant costs of portions of the compliance program differ among the areas within the Regional Entity. Within the U.S. portion of NPCC all costs attributable to delegated (statutory) functions performed by NPCC, including all compliance functions, are assessed based on a NEL allocation. Within the Canadian portion of NPCC those costs attributable to compliance functions performed by NPCC on behalf of provincial governmental and/or regulatory authorities are allocated consistent with the unique Memoranda of Understanding or Agreements that have been entered into for those provinces. To address these different compliance regimes, NPCC developed a composite cost allocation methodology that allocates U.S. only reliability assessment and compliance costs on a fair and equitable basis within the Regional Entity.

As an initial step of that methodology, the NEL for each of the BAAs and their relative percentage to the NPCC total NEL is calculated for the most recent year for which data is available, the second previous year. In order to establish the RE division funding requirements for each Balancing Authority Area on a NEL basis for all programs except for Compliance, the proposed expenses and fixed assets of all other programs are calculated and the adjustment for the RE division cash reserve requirement is identified. Any penalty monies received from NPCC registered entities within the U.S. prior to June 30th of the year preceding the business plan and budget year are then allocated among the NPCC program areas based on their FTE ratio and between the U.S. BAAs based on their relative NELs. Consistent with each of the Canadian provincial MOUs and agreements, all penalty monies resulting from compliance actions within Canada, if any, would remain within the applicable province. The total budgeted fees for NPCC

workshop participation are indicated as a credit, with the resultant addition being the RE division assessment, without the compliance program costs, calculated on a NEL basis.

In accordance with the *NPCC Amended and Restated Bylaws* the CS division proposed expenses and fixed assets of all programs are calculated and the adjustment for the CS division cash reserve requirement is identified, with the resultant addition being the CS division funding requirement and assessment, calculated on a NEL basis

For costs associated with the RE division compliance program, NPCC's allocation methodology apportions XX% of the costs for the program, attributed to CORC Fundamentals (CF), between the BAAs in the United States and Canada on a NEL basis.

Audits and Investigations (AI) related costs, representing XX% of the costs of the compliance program, are allocated between U.S. and Canadian BAAs in NPCC, and among the Canadian provinces, using an audit-based methodology. The audit-based methodology incorporates relative costs based on categories of compliance audits which are reflective of their size and complexity, as well as the differing compliance program implementation models that are utilized in NPCC due to the international nature of the Regional Entity. The portion allocated to the U.S. BAAs in NPCC is calculated using the audit-based methodology, and this amount is then re-allocated between the New York and New England BAAs based on their relative NEL.

The remaining XX% of the costs of the compliance program represent Mitigation and Enforcement (ME) related costs and are allocated between U.S. and Canadian BAAs in NPCC, and among the Canadian provinces, using an enforcement activity based methodology. Based on historical data, NPCC reviewed each BAAs percentage of violations, mitigation plans and settlement agreements to determine each BAAs total average percentage of enforcement activities. The portion allocated to the U.S. BAAs in NPCC is calculated using the enforcement activity based methodology, and this amount is then re-allocated between the New York and New England BAAs based on their relative NEL.

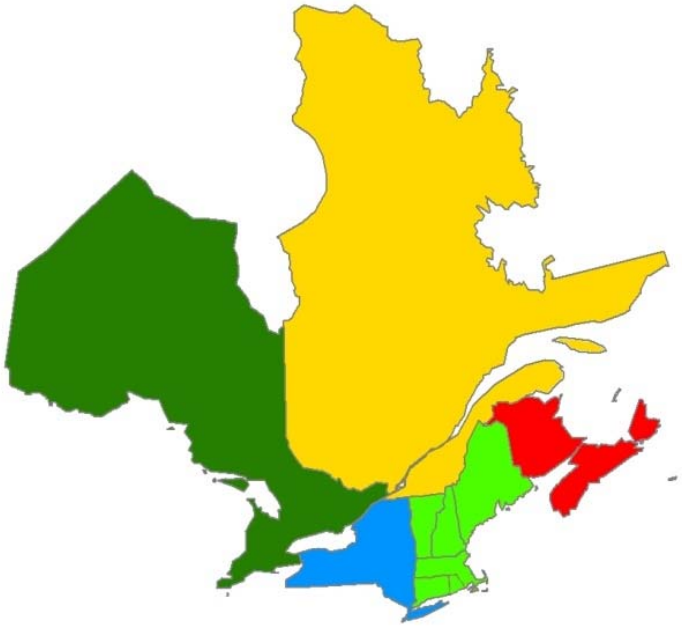
Any penalty monies received from NPCC registered entities within the U.S. by June 30th of the year preceding the business plan and budget year are then allocated among the NPCC program areas based on their FTE ratio and between the U.S. BAAs based on their relative NELs, and then added to the total compliance program expenses and fixed assets to yield a total compliance program assessment.

The CORC actual vs budget variance from the most recent year for which audited financials are available is broken out from the rest of the Adjustment to Cash Reserve and assigned to the CORC program allocation of costs. Within Quebec these costs are funded directly by the regulator, therefore, the assignment of program area variances needs to respect those specific circumstances.

Finally, the total RE division funding requirements and assessments by BAA are tabulated and the total funding requirements and assessments for NPCC, both the RE and CS divisions, are combined.

Table to be Inserted

Section B – Supplemental Financial Information
2018 Business Plan and Budget



Section B — Supplemental Financial Information

Reserve Balance

Table B-1 Reserve Balance

Working Capital and Operating Reserve Analysis 2017-2018
REGIONAL ENTITY DIVISION

	Total Reserve	Operating Reserve	Working Capital	Business Continuity
Beginning Working Capital and Operating Reserve, December 31, 2016	5,327,887	4,069,023	1,258,864	0
Plus: 2017 ERO Funding (from LSEs or designees)	14,255,061	14,255,061		
Plus: 2017 Other funding sources	64,000	64,000		
Less: 2017 Projected expenses & capital expenditures	(15,147,054)	(15,147,054)		
Projected Working Capital and Operating Reserve, December 31, 2017	**4,499,893**	**3,241,030**	**1,258,864**	**0**
Desired Working Capital and Operating Reserve, December 31, 2018 [1]	**2,933,713**	1,674,849 [2]	1,258,864 [3]	
19.42% of Total Regional Entity Budget of $15,106,967				
Desired Business Continuity Reserve, December 31, 2018 [4]	**940,000**			940,000
Less: Projected Working Capital and Operating Reserve, December 31, 2017	(4,499,893)	(3,241,030)	(1,258,864)	
Increase(decrease) in assessments to achieve desired Total Reserve	**(626,180)**	(1,566,180)	0	0

2018 Expenses and Capital Expenditures	15,106,967
Less: Penalty Sanctions [5]	(75,000)
Less: Other Funding Sources	(64,000)
Adjustment to achieve desired Total Reserve balance	(626,180)
2018 Assessment	**14,341,787**

[1] Total Reserve within a range of 16.67% - 33.33% of Budget.
[2] Operating Reserve within a range from 8.33% to 25.00% of Budget. $1,674,849 represents 11.09% of the 2017 budget of $15,106,967
[3] Working Capital equal to 8.33% of Budget. $1,258,864 represents 8.33% of the 2017 budget of $15,106,967
[4] Establish Business Continuity Reserve as approved by the NPCC Board of Directors upon recommendation by the MDCC.
[5] Represents collections July 1, 2016 to June 30, 2017.

Explanation of Changes in Reserve Policy from Prior Year

There was no change to the existing Working Capital and Operating Reserve Policy, however, a separate Business Continuity Reserve (BCR) in the amount of $1,000,000 (allocated between the Regional Entity and Criteria Services divisions) was established as approved by the NPCC Board of Directors, upon recommendation by the Management Development and Compensation Committee and endorsement by the Finance and Audit Committee, to be identified as restricted cash and drawn upon as subsequently brought before the Board of Directors in association with President & CEO succession related activities associated with a planned or sudden retirement, as well as other sudden changing workforce staffing requirements.

Breakdown by Statement of Activity Sections

The following detailed schedules are in support of the Regional Entity division Statement of Activities on page 13 of the 2018 Business Plan and Budget. All significant variances have been disclosed by program area in the preceding pages.

Penalty Sanctions

U.S. penalty monies received prior to June 30, 2017 are to be used to offset assessments in the 2018 Budget, as documented in the NERC Policy – Accounting, Financial Statement, and Budgetary Treatment of Penalties Imposed and Received for Violations of Reliability Standard. Penalty monies received from July 1, 2017 through June 30, 2018 will be used to offset U.S. load serving entity designee assessments in the 2018 Budget.

Allocation Method: U.S. penalty sanctions received have been allocated to the following Regional Entity division programs to reduce assessments: Reliability Standards; Compliance Monitoring & Enforcement and Organization Registration & Certification; Reliability Assessments and Performance Analysis; Training, Education and Operator Certification; and Situation Awareness and Infrastructure Security. U.S. penalty sanctions are allocated based upon the number of FTEs in the Program divided by the aggregate total FTEs in the Programs receiving the allocation.

Table B-2 Penalty Sanctions

Penalty Sanctions Received Prior to June 30, 2016	Date Received	Amount Received
Penalty Payment 1	12/16/2016	$ 75,000.00
Total Penalties Received		**$ 75,000.00**

Table B-3 Supplemental Funding

Outside Funding Breakdown By Program (excluding ERO Assessments & Penalty Sanctions)	Budget 2017	Projection 2017	Budget 2018	Variance 2018 Budget v 2017 Budget
Reliability Standards				
Total	$ -	$ -	$ -	$ -
Compliance Monitoring, Enforcement & Org. Registration				
	$ -	$ -	$ -	$ -
	-	-	-	-
Total	$ -	$ -	$ -	$ -
Reliability Assessment and Performance Analysis				
	$ -	$ -	$ -	$ -
	-	-	-	-
Total	$ -	$ -	$ -	$ -
Training and Education				
Workshops	$ 64,000	$ 64,000	$ 64,000	$ -
Total	$ 64,000	$ 64,000	$ 64,000	$ -
Situation Awareness and Infrastructure Security				
	$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	$ -
Technical Committees and Member Forums				
	$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	$ -
Administrative Services Programs				
	$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	$ -
Total Outside Funding	$ 64,000	$ 64,000	$ 64,000	$ -

Explanation of Significant Variances –2018 Budget versus 2017 Budget

- NPCC assumed no interest income because of continuing low market interest rates.

Table B-4 Personnel Expenses

Personnel Expenses	Budget 2017	Projection 2017	Budget 2018	Variance 2018 Budget v 2017 Budget	Variance %
Salaries					
Salary	$ 6,718,926	$ 6,718,926	$ 7,057,483	$ 338,557	5.0%
Employment Agency Fees	$ 10,000	$ 10,000	$ 10,000	$ -	0.0%
Temporary Office Services	$ 30,000	$ 30,000	$ 40,116	$ 10,116	33.7%
Total Salaries	$ 6,758,926	$ 6,758,926	$ 7,107,599	$ 348,673	5.2%
Total Payroll Taxes	$ 404,319	$ 404,319	$ 411,440	$ 7,121	1.8%
Benefits					
Education Reimbursement	$ 22,500	$ 22,500	$ 30,000	$ 7,500	33.3%
Training and Seminars	$ 36,860	$ 36,860	$ 44,232	$ 7,372	20.0%
Medical Insurance	$ 790,034	$ 790,034	$ 811,369	$ 21,335	2.7%
Life-LTD-STD Insurance	$ 88,716	$ 88,716	$ 90,465	$ 1,749	2.0%
Worker's Compensation	$ 15,000	$ 15,000	$ 15,000	$ -	0.0%
Vacation	$ 462,494	$ 462,494	$ 485,312	$ 22,818	4.9%
Relocation	$ -	$ -	$ -	$ -	-
Total Benefits	$ 1,415,603	$ 1,415,603	$ 1,476,378	$ 60,774	4.3%
Retirement					
Pension Contribution	$ 37,000	$ 37,000	$ 38,000	$ 1,000	2.7%
Employee Savings Plan	$ 727,223	$ 727,223	$ 714,353	$ (12,869)	-1.8%
Savings Admin	$ 45,000	$ 45,000	$ 35,000	$ (10,000)	-22.2%
Deferred Compensation	$ 38,000	$ 38,000	$ 38,000	$ -	0.0%
Total Retirement	$ 847,223	$ 847,223	$ 825,353	$ (21,869)	-2.6%
Total Personnel Costs	**$ 9,426,071**	**$ 9,426,071**	**$ 9,820,770**	**$ 394,699**	**4.2%**
FTEs	36.86	36.86	36.86	-	0.0%
Cost per FTE					
Salaries	$ 183,367	$ 183,367	$ 192,827	$ 9,459	5.2%
Payroll Taxes	$ 10,969	$ 10,969	$ 11,162	$ 193	1.8%
Benefits	$ 38,405	$ 38,405	$ 40,054	$ 1,649	4.3%
Retirement	$ 22,985	$ 22,985	$ 22,392	$ (593)	-2.6%
Total Cost per FTE	**$ 255,726**	**$ 255,726**	**$ 266,434**	**$ 10,708**	**4.2%**

Explanation of Significant Variances –2018 Budget versus 2017 Budget

- Temporary office services were increased to provide assistance in administrative services.
- Education reimbursement cost is based on additional employee that has expressed interest in pursuing an advanced degree.
- Savings administration decrease is due to the termination of the defined benefit plan.

Table B-5 Meeting Expense

Meeting Expenses	Budget 2017	Projection 2017	Budget 2018	Variance 2018 Budget v 2017 Budget	Variance %
Meetings	$ 377,100	$ 377,100	$ 353,050	$ (24,050)	-6.4%
Travel	$ 855,232	$ 855,232	$ 834,500	$ (20,732)	-2.4%
Conference Calls	$ 37,000	$ 37,000	$ 37,000	$ -	0.0%
Total Meeting Expenses	**$ 1,269,332**	**$ 1,269,332**	**$ 1,224,550**	**$ (44,782)**	**-3.5%**

Explanation of Significant Variances –2018 Budget versus 2017 Budget

- Continued efforts to limit the number of attendees to offsite meetings and hold more meetings on-site and via webinar.

Table B-6 Consultants and Contracts

Consultants	Budget 2017	Projection 2017	Budget 2018	Variance 2018 Budget v 2017 Budget	Variance %
Consultants					
Reliability Standards	$ -	$ -	$ -	$ -	-
Compliance Enforcement and Organization Registration and Certification	$ -	$ -	$ -	$ -	-
Reliability Assessment and Performance Analysis	$ 35,000	$ 35,000	$ -	$ (35,000)	-100.0%
Training and Education	$ -	$ -	$ -	$ -	-
Situation Awareness and Infrastructure Security	$ -	$ -	$ -	$ -	-
Member Forums	$ -	$ -	$ -	$ -	-
General and Administrative	$ 30,000	$ 30,000	$ -	$ (30,000)	-100.0%
Legal and Regulatory	$ -	$ -	$ -	$ -	-
Information Technology	$ -	$ -	$ -	$ -	-
Human Resources	$ -	$ -	$ -	$ -	-
Accounting and Finance	$ -	$ -	$ -	$ -	-
Consultants Total	**$ 65,000**	**$ 65,000**	**$ -**	**$ (65,000)**	**-100.0%**

Contracts	Budget 2017	Projection 2017	Budget 2018	Variance 2018 Budget v 2017 Budget	Variance %
Reliability Standards	$ 10,000	$ 10,000	$ 10,000	$ -	0.0%
Compliance Enforcement and Organization Registration and Certification	$ 1,274,000	$ 1,274,000	$ 1,254,000	$ (20,000)	-1.6%
Reliability Assessment and Performance Analysis	$ 378,000	$ 378,000	$ 401,640	$ 23,640	6.3%
Training and Education	$ -	$ -	$ -	$ -	-
Situation Awareness and Infrastructure Security	$ 160,000	$ 160,000	$ 120,000	$ (40,000)	-25.0%
Member Forums	$ -	$ -	$ -	$ -	-
General and Administrative	$ 115,000	$ 115,000	$ 85,000	$ (30,000)	-26.1%
Legal and Regulatory	$ -	$ -	$ -	$ -	-
Information Technology	$ -	$ -	$ -	$ -	-
Human Resources	$ -	$ -	$ -	$ -	-
Accounting and Finance	$ 7,000	$ 7,000	$ 7,000	$ -	0.0%
Contracts Total	**$ 1,944,000**	**$ 1,944,000**	**$ 1,877,640**	**$ (66,360)**	**-3.4%**
Total Consultants and Contracts	**$ 2,009,000**	**$ 2,009,000**	**$ 1,877,640**	**$ (131,360)**	**-6.5%**

Explanation of Significant Variances –2018 Budget versus 2017 Budget

- Ongoing effort to decrease the use of consultants and contractors when possible. (See program area sections for detail regarding a specific program area.)

Table B-7 Office Rent

Office Rent	Budget 2017	Projection 2017	Budget 2018	Variance 2018 Budget v 2017 Budget	Variance %
Office Rent	$ 650,000	$ 650,000	$ 650,000	$ -	0.0%
Utilities	$ 43,000	$ 43,000	$ 43,000	$ -	0.0%
Maintenance	$ 40,000	$ 40,000	$ 35,000	$ (5,000)	-12.5%
Security	$ 2,700	$ 2,700	$ 2,700	$ -	0.0%
Real Estate Taxes	$ 74,000	$ 74,000	$ 80,000	$ 6,000	8.1%
Total Office Rent	**$ 809,700**	**$ 809,700**	**$ 810,700**	**$ 1,000**	**0.1%**

Explanation of Significant Variances –2018 Budget versus 2017 Budget

- Projected increase in real estate taxes.

Table B-8 Office Costs

Office Costs	Budget 2017	Projection 2017	Budget 2018	Variance 2018 Budget v 2017 Budget	Variance %
Telephone	$ 112,000	$ 112,000	$ 111,660	$ (340)	-0.3%
Internet Expense	$ 105,600	$ 105,600	$ 95,000	$ (10,600)	-10.0%
Office Supplies	$ 33,000	$ 33,000	$ 33,000	$ -	0.0%
Computer Supplies and Maintenance	$ 350,000	$ 350,000	$ 350,600	$ 600	0.2%
Subscriptions & Publications	$ 13,500	$ 13,500	$ 13,500	$ -	0.0%
Dues	$ 4,400	$ 4,400	$ 3,400	$ (1,000)	-22.7%
Postage	$ 1,200	$ 1,200	$ 1,200	$ -	0.0%
Express Shipping	$ 10,000	$ 10,000	$ 10,000	$ -	0.0%
Copying	$ 26,400	$ 26,400	$ 26,400	$ -	0.0%
Reports	$ 6,000	$ 6,000	$ 8,000	$ 2,000	33.3%
Stationary and Office Forms	$ 2,000	$ 2,000	$ 2,000	$ -	0.0%
Equipment Repair/Service Contracts	$ -	$ -	$ -	$ -	-
Bank Charges	$ 15,000	$ 15,000	$ 10,000	$ (5,000)	-33.3%
Sales and Use Tax	$ -	$ -	$ -	$ -	-
Merchant Credit Card Fees	$ -	$ -	$ -	$ -	-
Presentation and Publicity	$ -	$ -	$ -	$ -	-
Total Office Costs	**$ 679,100**	**$ 679,100**	**$ 664,760**	**$ (14,340)**	**-2.1%**

Explanation of Significant Variances –2018 Budget versus 2017 Budget

Total Office costs are expected to remain relatively flat.

Table B-9 Professional Services

Professional Services	Budget 2017	Projection 2017	Budget 2018	Variance 2018 Budget v 2017 Budget	Variance %
BOT Fee	$ 325,000	$ 325,000	$ 340,000	$ 15,000	4.6%
BOT Search Fee	$ 20,000	$ 20,000	$ -	$ (20,000)	-100.0%
Legal - Reorganization	$ -	$ -	$ -	$ -	-
Accounting & Auditing Fees	$ 310,000	$ 310,000	$ 300,000	$ (10,000)	-3.2%
Legal Fees - Other	$ 316,000	$ 316,000	$ 250,000	$ (66,000)	-20.9%
Insurance - Commercial	$ 70,000	$ 70,000	$ 70,000	$ -	0.0%
Total Services	**$ 1,041,000**	**$ 1,041,000**	**$ 960,000**	**$ (81,000)**	**-7.8%**

Explanation of Significant Variances –2018 Budget versus 2017 Budget

- Legal fees are projected to be lower based on additional workload taken on by in-house legal team.

Table B-10 – Miscellaneous

Miscellaneous Expense	Budget 2017	Projection 2017	Budget 2018	Variance 2018 Budget v 2017 Budget	Variance %
Miscellaneous Expense	$ 50,000	$ 50,000	$ 50,000	$ -	0.0%
Total Miscellaneous Expense	**$ 50,000**	**$ 50,000**	**$ 50,000**	**$ -**	**0.0%**

Table B-11 Other Non-Operating Expenses

Other Non-Operating Expenses	Budget 2017	Projection 2017	Budget 2018	Variance 2018 Budget v 2017 Budget	Variance %
Interest Expense	$ -	$ -	$ -	$ -	-
Office Relocation	$ -	$ -	$ -	$ -	-
Total Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**-**

Table B-12 Fixed Assets

Fixed Assets	Budget 2017	Projection 2017	Budget 2018	Variance 2018 Budget v 2017 Budget	Variance %
Depreciation	$ (250,000)	$ (250,000)	$ (269,000)	$ (19,000)	7.6%
Equipment CapEx	$ -	$ -	$ -	$ -	-
Computer & Software CapEx	$ 276,000	$ 276,000	$ 115,000	$ (161,000)	-58.3%
Furniture & Fixtures CapEx	$ -	$ -	$ -	$ -	-
Leasehold Improvements	$ -	$ -	$ -	$ -	-
Allocation of Fixed Assets	$ -	$ -	$ -	$ -	-
Total Increase (Decrease) in Fixed Assets	**$ 26,000**	**$ 26,000**	**$ (154,000)**	**$ (180,000)**	**-692.3%**

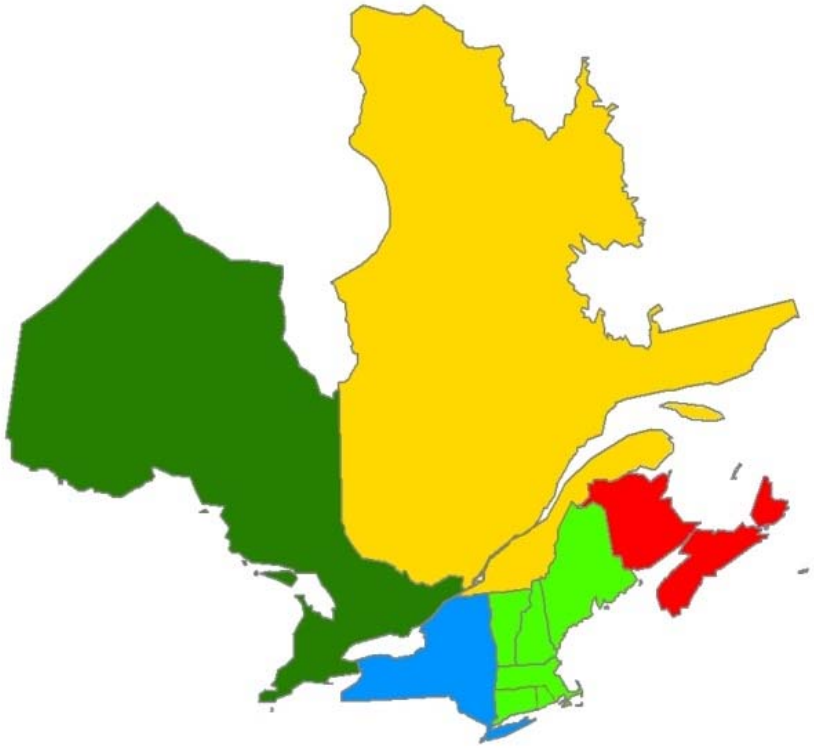
Table B-13 2018 and 2019 Projections

	Table to be Inserted	

Assumptions

Section C – Criteria Services Division Activities

2018 Business Plan and Budget



Section C —2018 Criteria Services Division Business Plan and Budget

Criteria Services Division (in w hole dollars)	2017 Budget	2018 Budget	Increase (Decrease)
Total FTEs	2.14	2.14	0.00
Total Direct Expenses	$623,747	$666,530	$42,783
Total Indirect Expenses	$413,149	$416,453	$3,304
Other Non-Operating Expenses	$0	$0	$0
Working Capital and Operating Reserves Requirement	$78,971	($47,843)	($126,813)
Inc(Dec) in Fixed Assets	($10,000)	($16,000)	($6,000)
Funding Requirement	$1,105,867	$1,019,141	($86,726)

NPCC Regionally-Specific Criteria Services Background

NPCC Criteria Services division activities are based on the development, maintenance (including retirement when no longer needed), and promulgation of Regionally-specific more stringent criteria, as well as criteria establishing resource adequacy requirements within the Region. These criteria contain requirements which are more stringent, more specific or augment the existing NERC Reliability Standards requirements. These criteria require continual evaluation to ensure they are "not inconsistent with" any NERC reliability standards as the standards are approved by FERC and the applicable provincial governmental authorities, as per the NERC Rules of Procedure.

Membership and Governance

Full members are subject to compliance with Regionally-specific criteria, in addition to continent-wide Reliability Standards, and receive criteria-related services from the Criteria Services division.

Full Members, aside from those who perform the Balancing Authority function, are not assessed an annual membership fee. Those that perform Balancing Authority functions are assessed and remit a proportional net energy for load share of expenses for criteria services. NPCC would also directly assign criteria service division costs to a Balancing Authority Area or entity, where significant costs are incurred for that Balancing Authority Area. The funding for NPCC's Criteria Services division is approved by the NPCC Board of Directors.

Criteria Services Division Functional Scope

Through its Criteria Services division, NPCC promotes the reliable and efficient operation of the international, interconnected bulk power systems in Northeastern North America through the establishment of Regionally-specific criteria, and monitoring and enforcement of compliance with such criteria.

NPCC provides Full Members with Regional reliability assurance services, and acts as the vehicle through which States and Provinces can fulfill their political mandates, with respect to resource adequacy, as well as overseeing the Northeastern North American electric infrastructure.

Major 2018 Assumptions and Cost Impacts

The Criteria Services division services are expected to remain stable throughout 2018

- The Criteria Compliance Enforcement Program (CCEP) review and evaluation process is the mechanism for monitoring key criteria attributes as determined by the respective NPCC Task Forces and the Compliance Committee.
- Past non-compliances, if any, followed the due process stated in the CCEP-1 process document and proper resolution/enforcement action taken.

2018 Primary Goals and Objectives

- Continue with the development and maintenance of a set of NPCC Directories which are "not inconsistent with" the NERC Reliability Standards and which clearly delineate the more stringent NPCC criteria requirements
    - The combination of North American and more-stringent NPCC Regional criteria provide for consistency and operational clarity while providing more robust defense in–depth, results based, criteria requirements to ensure BPS reliability
    - Continually review the criteria found in the NPCC Directories and the ERO standards to ensure no redundancies or inconsistencies exist.
    - Retire Directories and/or Criteria which have been overtaken by improved NERC standards
    - Continually file revised and updated more stringent requirements with the New York State Department of Public Service and Canadian Provinces as applicable
- Review, maintain, and revise the NPCC Regional Reliability Directories to facilitate compliance assessments and ensure the Criteria portions of the Directories are "not inconsistent" with, nor duplicative with, the approved and effective NERC Standards.
- The criteria services division and CCEP Working Group (reporting to the Compliance Committee) will work with the various Task Forces to develop Criteria Compliance Reporting Forms for any additional NPCC Directories to ensure that the more stringent or Regionally-specific criteria is being met.
- The criteria services division and CCEP working group will work with TFCO, TFCP, TFSS, and TFSP to review criteria and measures within each specific NPCC Directory to identify and develop them into specific reporting forms for approval.
- Continually review impact of Bulk Electric System definition on Directory and Criteria content and compliance reporting.
- Continually review potential impacts of Sector or NPCC organizational changes on the Directories and Criteria by performing a review of enforcement and arbitration processes as needed
- Assist Legal with preparation of revised Directories for Regulatory filings with the individual Provinces in accordance with their respective Memorandum of Understandings (MOUs) as well as the State of New York Public Service Commission
- Facilitate any requested clarifications for NPCC Criteria with the necessary subject matter experts and also identify any other potential opportunities for clarifications of the Criteria.
- Conduct review of the following Documents:

- Directory No. 7 – *Special Protection Systems* – the TFSP will serve as lead Task Force working in conjunction with TFCP and TFSS on revisions required to ensure consistency with the development of the NERC standard on Remedial Action Schemes.
- *A-10 - Classification of Bulk Power System Elements* - the TFCP will conclude its review of the A-10 methodology in 2018.
- Review and respond to Requests for Clarifications to existing NPCC Standards, Directories, and Criteria.

NPCC Reliability Directory Maintenance and Development

The NPCC Regional Reliability Directories were developed to demonstrate that the NPCC more stringent criteria are "not inconsistent with" the NERC Reliability Standards as mandated by the NERC Rules of Procedure. The conversion of NPCC's criteria into Directories was undertaken to remove any redundancies with the NERC or NPCC Regional Reliability Standards and to clearly delineate the more stringent NPCC criteria requirements, assign Functional Model designations to those responsible for compliance and create measurable compliance criteria. Subsequent to the initial establishment of the Directories, which also organized functionally related B Guidelines and C Procedures into a single Directory, the Directories were further reviewed to translate existing criteria language into a "requirement type" format. The development of the criteria into NERC style requirements facilitates the NPCC Region's CCEP and also ensures the delineation of the more stringent and more specific Regional criteria from the latest approved and effective set of NERC ERO standards.

In 2018, work will continue with the maintenance, revision, or potential retirement of individual Directories to address any actual or anticipated redundancies with new or modified NERC or NPCC Reliability Standards. The ongoing review and maintenance of the Directories will require Task Force and Criteria Services staff to support this effort and to serve as subject matter experts. In addition to the ongoing review of the criteria within the Directories for potential duplicity with the NERC standards, any Directories that have not had the criteria translated into NERC style requirements will also be reviewed in order to achieve criteria 'requirements' which are clear, concise and measurable. Also, a standards style template will be applied to the existing Directories to make them more consistent with the look of the standards. As NERC standards improve, the need for NPCC Directories and the amount of criteria contained therein will decrease over time, however in the interim, significant review is necessary to ensure the criteria remain "not inconsistent with" the NERC standards as outlined in the NERC Rules of Procedure. NPCC will conduct internal reviews of all draft standards against Regional criteria and utilize subject matter experts to identify reliability and compliance related concerns. NPCC will file the revised NPCC Directories and notifications of retirements of Directories with the Canadian governmental and/or provincial Regulatory authorities within the NPCC "footprint", on an as needed basis, in accordance with established provincial procedures and agreements executed with NPCC.

NPCC Operations and Planning Directories

The following Directories are envisioned to remain active for 2018.

Directory #1, *Design and Operation of the Bulk Power System.*

This Directory documents NPCC's Regionally-specific, more stringent criteria, and demonstrates coordination and consistency with all the existing NERC TPL, BAL, IRO, INT, MOD, TOP, PRC and VAR standards. The NPCC TFCP and TFCO completed a review of the Directory#1 criteria in 2015, during which the criteria was translated into NERC style requirements and revisions were enacted to ensure consistency with recent changes to the TPL and TOP standards.

Directory #2, *Emergency Operations*
This Directory documents NPCC's Regionally-specific, more stringent criteria, and demonstrates coordination and consistency with all the existing NERC EOP and TOP standards. The NPCC Task Force on Coordination of Operation is reviewing this Directory in 2017.

Directory # 4, *System Protection Criteria*
This Directory documents NPCC's Regionally-specific, more stringent criteria, and demonstrates coordination and consistency with certain applicable NERC PRC standards. The NPCC Task Force on System Protection will lead this review and revision.

Directory # 5, *Reserve*
This Directory documents NPCC's Regionally-specific, more stringent criteria, and demonstrates coordination and consistency with all the existing applicable NERC BAL, INT, and IRO standards. The NPCC Task Force on Coordination of Operation will lead this review and revision and ensure consistency with the BAL standards.

Directory # 7, *Special Protection Systems*
This Directory documents NPCC's Regionally-specific, more stringent criteria for application and approval of SPS. The NPCC Task Force on System Protection will lead this review and revision and ensure consistency with the Remedial Action Scheme PRC-012 standard.

Directory # 8, *System Restoration*
This Directory documents NPCC's Regionally-specific, more stringent criteria with which each applicable entity must plan for and perform power system restoration following a major or a total blackout, and demonstrates coordination and consistency with applicable NERC EOP standards. The NPCC Task Force on Coordination of Operation will lead this review and revision.

Directory # 11, *Disturbance Monitoring Equipment*,
This directory documents NPCC's Regionally-specific, more stringent criteria, and demonstrates coordination and consistency with certain existing NERC PRC standards. The NPCC Task Force on System Protection anticipates the development and approval of Directory#11 in order to facilitate the retirement of PRC -002-NPCC-1 and will lead this review and revision.

Directory # 12, *Automatic UFLS Program Requirements*,
This Directory documents NPCC's Regionally-specific, more stringent criteria, and demonstrates coordination and consistency with certain existing NERC and NPCC PRC standard(s). The NPCC Task Force on System Studies will lead this review and revision until such time as the NPCC PRC-006-01 UFLS Regional Standard is approved by the NPCC membership, NERC BOT, the FERC and all the applicable governmental authorities in the Provinces of Canada within NPCC's footprint.

NPCC Criteria Compliance Background

The NPCC criteria services division assures the reliable operation of the bulk power system through implementation of a comprehensive compliance program. This program which includes monitoring, assessing and enforcing compliance with the more stringent, Regionally specific NPCC Criteria requirements, is known as the NPCC Criteria Compliance and Enforcement Program (CCEP) described in process document CCEP-1. This program was developed by the criteria services division and the CCEP Working Group under the purview of the NPCC Compliance Committee. The results of this program support the various Task Forces in their assessments of the NPCC criteria in meeting their goals for the Reliability Coordinating Committee as stated in Section A of this Business Plan.

The more stringent, Regionally-specific NPCC Criteria requirements reflect the unique operational and planning aspects of the bulk power system within the NPCC Region and are included in the NPCC "A" documents and their successors, the NPCC Directories.

NPCC issues non-monetary sanctions to enforce compliance with NPCC Criteria.

- The CCEP program is described in document CCEP-1, *NPCC Criteria Compliance and Enforcement Program (CCEP) Process Document*
- The implementation plan is described in document CCEP-2, *Implementation Plan for 2011 NPCC Criteria Compliance and Enforcement Program*
- On April 5, 2011, the above became effective upon Full Member approval of CCEP-1, and CCEP-2 and retired the following
    - NPCC Criteria A-8, Reliability Compliance and Enforcement Program (RCEP)
    - NPCC Guide B-22, Guidelines for Implementation of the NPCC Inc. Compliance Program
    - NPCC Procedure C-32, Review Process for NPCC Reliability Compliance Enforcement Program
    - Each of the above have been annotated as "retired effective 4/5/11 upon Full Member approval of CCEP-1… and CCEP-2…" on the NPCC public website

- The CCEP-1 document recognizes the applicability of NPCC's Regionally-specific, more stringent reliability criteria to the Full Members of NPCC, consistent with the *Amended and Restated ByLaws*, and respects the provisions of the several Canadian Memoranda of Understanding in the execution of the processes described
- Provides a comprehensive CCEP Process Diagram showing the process of evaluating and approving Criteria Certification submittals, and additional processes and responsibilities in the event that non-compliances, disputes and sanctions arise
- Describes the roles and responsibilities of Reporting Members, the CC, the RCC and the Enforcement Panel in the compliance review and enforcement process
- Describes Levels of Non-Compliance, associated non-monetary Sanctions, Lateness Policy and the Arbitration/Dispute Resolution process
- Addresses Mitigation Plans for any violations under the enforcement process; and
- Lists the mandatory Certification Forms to be submitted for review by the Task Forces to ensure compliance with NPCC Directories are being met

The CCEP currently requires annual submittal of Certification Forms by the Reliability Coordinators and Balancing Authorities to confirm compliance with various NPCC Directories. Currently the required Certification forms are for Directory #1- *Area Transmission Review*, Directory #8 - *Key Facility List*, Directory #9 – *Generator Real Power Verification*, Directory #10 - *Verification of Generator Gross and Net Reactive Power Capability*, and Directory #12 - *UFLS Program Requirements*. In 2017 NPCC will consider an expansion of the CCEP to include compliance assessment activities to other active Directories.

The CCEP identifies those specific NPCC Directories that are subject to monitoring, assessment and enforcement.

The NPCC Compliance Committee (CC) has final approval of compliance assessments related to CCEP. The CCEP describes the roles and responsibilities of committees and panels used to resolve contested compliance and/or sanction or penalty determinations related to NPCC Directories.

Explanation of Significant Variances – 2018 Budget versus 2017 Budget

Resource Requirements

Personnel

- NPCC anticipates no need to hire additional personnel in this program area in 2018.

2017 Budget and Projection and 2018 Budget Comparisons

Statement of Activities and Capital Expenditures
2017 Budget & Projection, and 2018 Budget
CRITERIA SERVICES DIVISION

		2017 Budget	2017 Projection	Variance 2017 Projection v 2017 Budget Over(Under)	2018 Budget	Variance 2018 Budget v 2017 Budget Over(Under)
Funding						
ERO Funding						
	ERO Assessments	$ -	$ -	$ -	$ -	$ -
	Penalty Sanctions	-	-	-	-	-
Total ERO Funding		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
	Membership Dues	1,105,867	1,105,867	-	1,019,141	(86,726)
	Testing Fees	-	-	-	-	-
	Services & Software	-	-	-	-	-
	Workshops	-	-	-	-	-
	Interest	-	-	-	-	-
	Miscellaneous	-	-	-	-	-
Total Funding (A)		**$ 1,105,867**	**$ 1,105,867**	**$ -**	**$ 1,019,141**	**$ (86,726)**
Expenses						
Personnel Expenses						
	Salaries	$ 401,142	$ 401,142	$ -	$ 404,848	$ 3,706
	Payroll Taxes	23,301	23,301	-	23,413	112
	Benefits	69,100	69,100	-	74,991	5,892
	Retirement Costs	42,605	42,605	-	43,272	667
Total Personnel Expenses		**$ 536,147**	**$ 536,147**	**$ -**	**$ 546,523**	**$ 10,376**
Meeting Expenses						
	Meetings	$ 5,000	$ 5,000	$ -	$ 5,000	$ -
	Travel	51,600	51,600	-	55,647	4,047
	Conference Calls	-	-	-	-	-
Total Meeting Expenses		**$ 56,600**	**$ 56,600**	**$ -**	**$ 60,647**	**$ 4,047**
Operating Expenses						
	Consultants & Contracts	$ 18,000	$ 18,000	$ -	$ 40,360	$ 22,360
	Office Rent	-	-	-	-	-
	Office Costs	-	-	-	-	-
	Professional Services	-	-	-	-	-
	Computer & Equipment Leases	-	-	-	-	-
	Miscellaneous	3,000	3,000	-	3,000	-
	Depreciation	10,000	10,000	-	16,000	6,000
Total Operating Expenses		**$ 31,000**	**$ 31,000**	**$ -**	**$ 59,360**	**$ 28,360**
	Total Direct Expenses	**$ 623,747**	**$ 623,747**	**$ -**	**$ 666,530**	**$ 42,783**
Indirect Expenses		**$ 413,149**	**$ 413,149**	**$ -**	**$ 416,453**	**$ 3,304**
Other Non-Operating Expenses		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)		**$ 1,036,896**	**$ 1,036,896**	**$ -**	**$ 1,082,983**	**$ 46,087**
Change in Assets		**$ 68,971**	**$ 68,971**	**$ -**	**$ (63,843)**	**$ (132,813)**
Fixed Assets						
	Depreciation	$ (10,000)	(10,000)	$ -	$ (16,000)	$ (6,000)
	Computer & Software CapEx	-	-	-	-	-
	Furniture & Fixtures CapEx	-	-	-	-	-
	Equipment CapEx	-	-	-	-	-
	Leasehold Improvements	-	-	-	-	-
	Allocation of Fixed Assets	-	-	-	-	-
Inc(Dec) in Fixed Assets (C)		**(10,000)**	**(10,000)**	**-**	**(16,000)**	**(6,000)**
TOTAL BUDGET (=B+C)		1,026,896	1,026,896	-	1,066,983	40,087
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)		**$ 78,971**	**$ 78,971**	**$ -**	**$ (47,843)**	**$ (126,813)**

Personnel Analysis

Total FTE's by Program Area	Budget 2017	Projection 2017	Direct FTEs 2018 Budget	Shared FTEs1 2018 Budget	Total FTEs 2018 Budget	Change from 2017 Budget
CRITERIA SERVICES DIVISION						
Operational Programs						
Reliability Standards	1.07	1.07	1.00	0.07	1.07	0.00
Compliance Enforcement and Organization Registration and Certification	0.00	0.00	0.00	0.00	0.00	0.00
Training and Education	0.00	0.00	0.00	0.00	0.00	0.00
Reliability Assessment and Performance Analysis	1.07	1.07	1.00	0.07	1.07	0.00
Situation Awareness and Infrastructure Security	0.00	0.00	0.00	0.00	0.00	0.00
Total FTEs Operational Programs	**2.14**	**2.14**	**2.00**	**0.14**	**2.14**	**0.00**
Administrative Programs						
Member Forums	0.00	0.00	0.00	0.00	0.00	0.00
General and Administrative	0.00	0.00	0.00	0.00	0.00	0.00
Information Technology	0.00	0.00	0.00	0.00	0.00	0.00
Legal and Regulatory	0.00	0.00	0.00	0.00	0.00	0.00
Human Resources	0.00	0.00	0.00	0.00	0.00	0.00
Accounting and Finance	0.00	0.00	0.00	0.00	0.00	0.00
Total FTEs Administrative Programs	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Total FTEs	**2.14**	**2.14**	**2.00**	**0.14**	**2.14**	**0.00**

[1]A shared FTE is defined as an employee who performs both Regional Entity and Criteria Services division functions.

Reserve Analysis 2017 - 2018

Working Capital and Operating Reserve Analysis 2017-2018
CRITERIA SERVICES DIVISION

	Total Reserve	Operating Reserve	Working Capital	Business Continuity
Beginning Total Reserve, December 31, 2016	384,529	295,774	88,755	
2017 Non-Statutory Funding (from members)	1,105,867	1,105,867	0	
2017 Other funding sources	0	0	0	
Less: 2017 Projected expenses & fixed asset additions	(1,026,896)	(1,026,896)	0	
Projected Working Capital and Operating Reserve, December 31, 2017	**463,500**	**374,745**	**88,755**	
Desired Working Capital and Operating Reserve, December 31, 2018 [1]	**355,657**	266,746 [2]	88,912 [3]	
Desired Business Continuity Reserve, December 31, 2018	**60,000**			60,000
Less: Projected Working Capital and Operating Reserve, December 31, 2017	(463,500)	(374,745)	(88,755)	
Increase(decrease) in assessments to achieve desired Total Reserve	(47,843)	(107,999)	157	

2018 Funding requirement for expenses and fixed asset additions	1,066,983
Adjustment to achieve desired Working Capital and Operating Reserve balance	(47,843)
2017 Funding and reserve requirement	1,019,141

[1] Total Reserve within a range of 16.67% - 33.33% of Budget.

[2] Total NPCC Operating Reserve must be within a range from 8.33% to 25.00% of Budget. $266,746 represents 25.00% of the 2017 CS budget of $1,066,983.

[3] Total NPCC Working Capital must equal 8.33% of Budget. $88,912 represents 8.33% of the 2017 CS budget of $1,066,983.

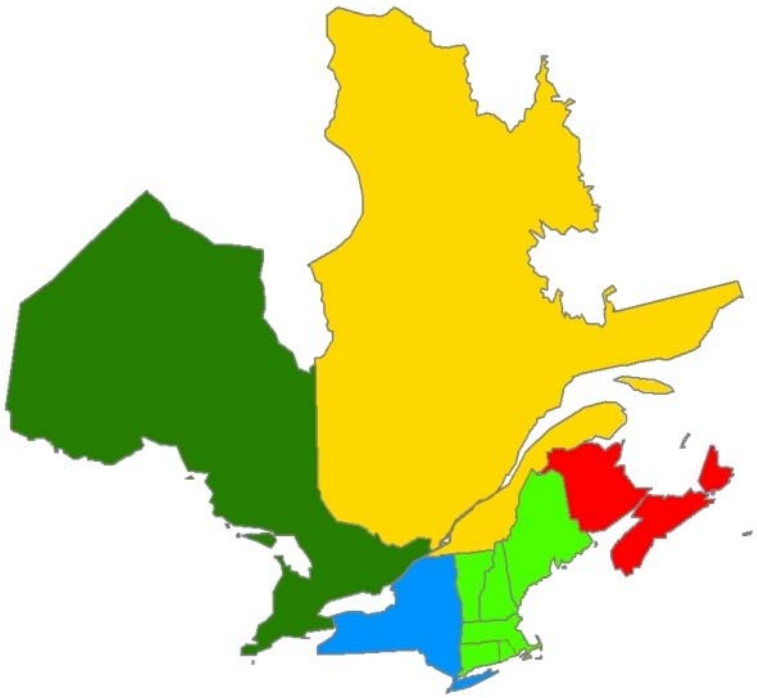
[4] Establish Business Continuity Reserve as approved by the NPCC Board of Directors upon recommendation by the MDCC.

Explanation of Changes in Reserve Policy from Prior Year

There was no change to the existing Working Capital and Operating Reserve Policy, however, a separate Business Continuity Reserve (BCR) in the amount of $1,000,000 (allocated between the Regional Entity and Criteria Services divisions) was established as approved by the NPCC Board of Directors, upon recommendation by the Management Development and Compensation Committee and endorsement by the Finance and Audit Committee, to be identified as restricted cash and drawn upon as subsequently brought before the Board of Directors in association with President & CEO succession related activities associated with a planned or sudden retirement, as well as other sudden changing workforce staffing requirements.

Section D – Additional Consolidated Financial Statements

2018 Business Plan and Budget



Section D — Additional Financial Statements

Statement of Financial Position

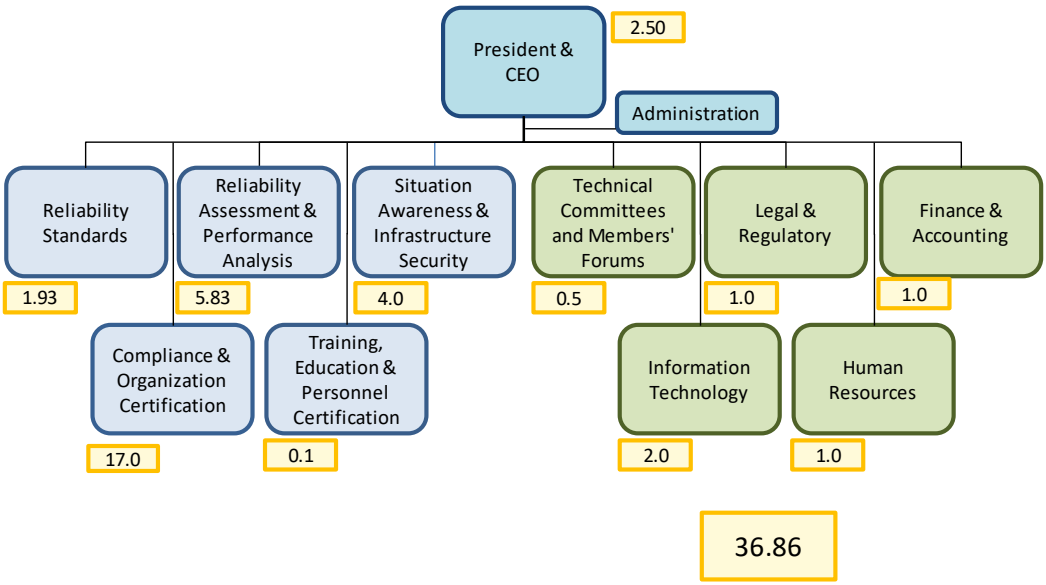
	Table to be Inserted	

	Table to be Inserted	

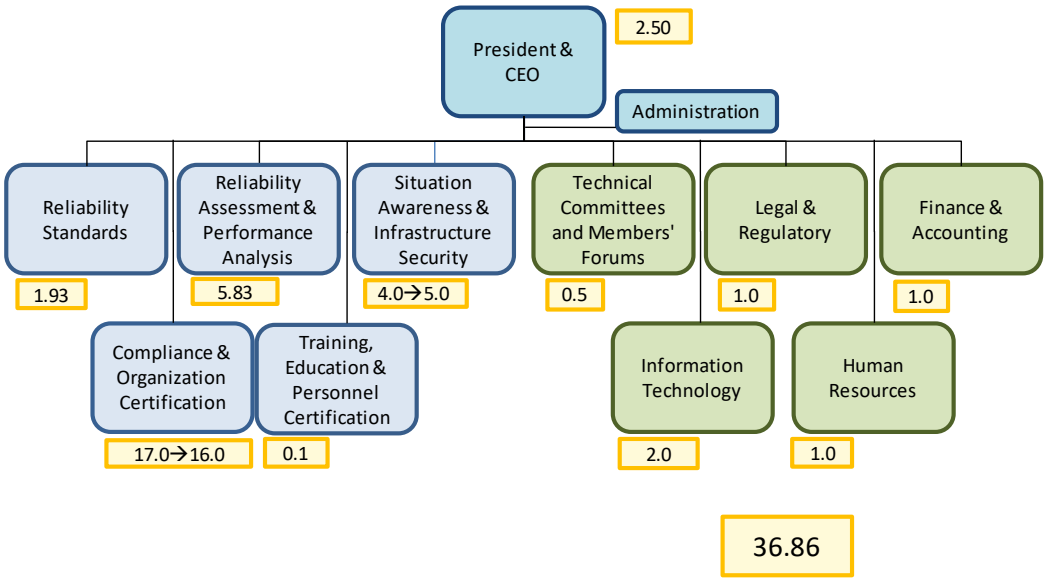
	Table to be Inserted	

Appendix A Staff Allocations

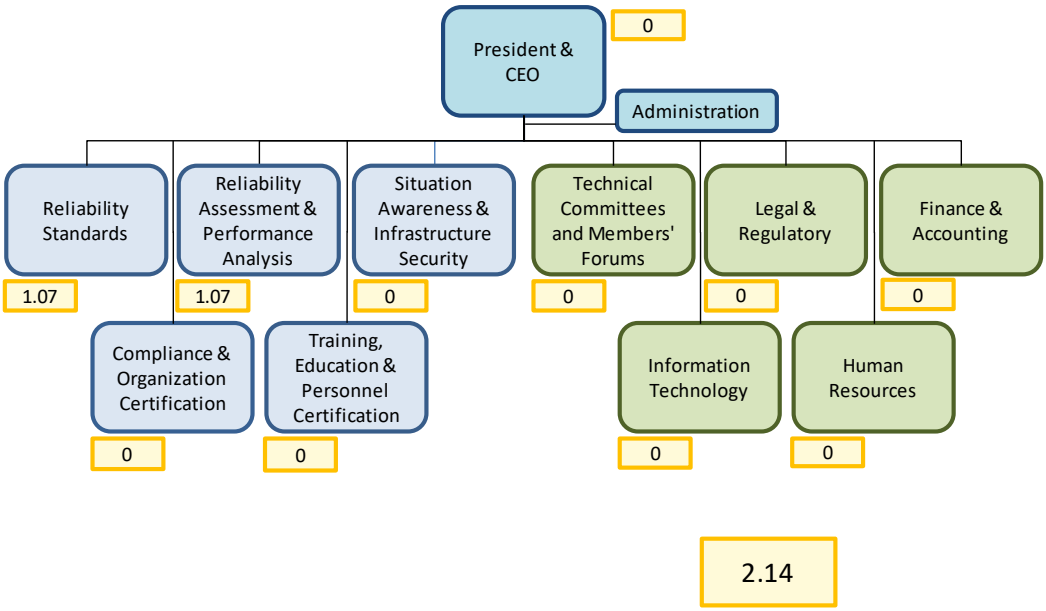
2017 Budget Staff Allocations - RE Division



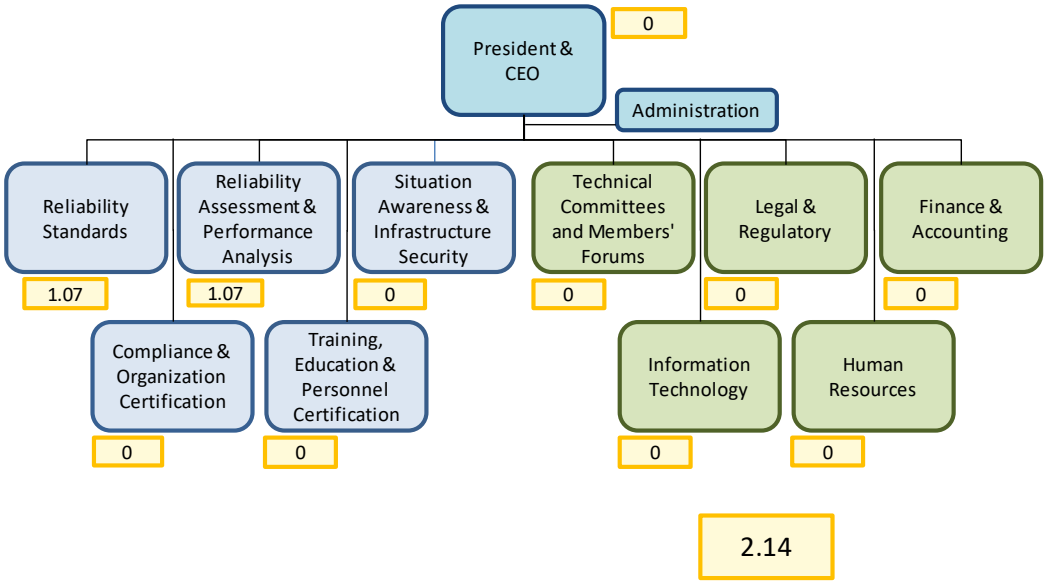
2018 Budget Staff Allocations - RE Division



2017 Budget Staff Allocations - CS Division



2018 Budget Staff Allocations - CS Division



Appendix B Acronyms

This section lists acronyms used in this document.

Acronym	Definition
AI	Audits and Investigations
BAA	Balancing Authority Area
BEPWG	BES Exception Process Working Group
BES	Bulk Electric System
BOT	Board of Trustees
BPS	Bulk Power System
CC	Compliance Committee
CCEP	Criteria Compliance Enforcement Program
CDAA	CMEP Data Administration Application
CEAP	Cost Effective Analysis Process
CEH	Continuing Education Hour
CGNC	Corporate Governance and Nominating Committee
CIPC	Critical Infrastructure Protection Committee
CIPIS	Critical Information Protection Information Sharing
CMEP	Compliance Monitoring and Enforcement Program
CORC	Compliance Monitoring and Enforcement and Organization Registration and Certification Program
CPP	Clean Power Plan
CRRA	Cost of Risk Reduction Analysis
CUG	Consortium Users Group
DADS	Demand Availability Data System
DADSWG	Demand Response Availability Data System Working Group
ERA	Entity Reliability Assessment
ERAG	Eastern Interconnection Reliability Assessment Group
ERO	Electric Reliability Organization
EUB	Electric Utility Board
EUB	Energy and Utilities Board
FAC	Finance and Audit Committee
FERC	Federal Energy Regulatory Commission
FFT	Find, Fix, Track
GADS	Generator Availability Data System
GADSWG	Generating Availability Data System Working Group
GMD	Geomagnetic Disturbance
HQCMÉ	Hydro-Québec Contrôle des mouvements d'énergie
HSIN	Homeland Security Information Network
ICE	Internal Controls Evaluation
IED	Intelligent Electronic Device
IERP	Independent Experts Review Panel Report
IESO	Independent Electricity System Operator
IRA	Inherent Risk Assessment
ISO	Independent System Operator
ITSG	IT Steering Group
LCEFT	Load, Capacity, Energy, Fuels, and Transmission
LMS	Learning Management System
LMWG	Load Modeling Working Group
LSE	Load Serving Entity
MACD	Market Assessment and Compliance Division of the IESO
MDCC	Management Development and Compensation Committee
ME	Mitigation and Enforcement
MMWG	Multi-Regional Modeling Working Group
MOU	Memorandum of Understanding
MPLS	Multiprotocol Label Switching
MVWG	Model Validation Working Group
NAESB	North American Electric Standards Review Board

Acronym	Definition
NEL	Net Energy for Load
NERC	North American Electric Reliability Corporation
NOAV	Notice of Alleged Violation
NOCV	Notice of Confirmed Violation
NOPR	Notice of Proposed Rulemaking
NOPV	Notice of Possible Violation
NPCC	Northeast Power Coordinating Council, Inc.
NRAP	NPCC Reliability Assessment program
NSPI	Nova Scotia Power Incorporated
NSUARB	Nova Scotia Utility and Review Board
OEB	Ontario Energy Board
PAS	Performance Analysis Subcommittee
PC	Pension Committee
PMOS	Project Management Oversight Subcommittee
PSMTF	Protection System Mis-operations Task Force
PSTN	Public Switched Telephone Network
QCMEP	Québec Reliability Standards Compliance Monitoring and Enforcement Program
RADS	Reliability Assessment Data System
RADWG	Reliability Assessment Data Working Group
RAS	Reliability Assessment Subcommittee
RC	Reliability Coordinator
RCC	Reliability Coordinating Committee
RISC	Reliability Issues Steering Committee
RSAW	Reliability Standards Audit Worksheet
RSC	Regional Standards Committee
RTO	Regional Transmission Organization
SAFNR	Situational Awareness-FERC, NERC, Regions
SAMS	System Analysis and Modeling Subcommittee
SAR	Standards Authorization Request
SAT	Systematic Approach to Training
SBS	Standards Balloting System
SCPS	Standards Committee Process Subcommittee
SDT	Standards Drafting Team
SEDS	Spare Equipment Database System
SEDTF	Spare Equipment Database Task Force
SPS	Special Protection Systems
TADS	Transmission Availability Data System
TADSWG	Transmission Availability Data System Working Group
TFCO	Task Force on Coordination of Operation
TFCP	Task Force on Coordination of Planning
TFE	Technical Feasibility Exception
TFIST	Task Force on Infrastructure Security and Technology
TFSP	Task Force on System Protection
TFSS	Task Force on System Studies
TLR	Transmission Loading Relief
TOP	Transmission Operator
UFLS	Underfrequency Load Shedding
UVLS	Under-Voltage Load Shedding
VRF	Violation Risk Factor
VSL	Violation Security Level

Appendix C Index of Figures and Tables

Figure 1.	Budget by Program Area Chart	11
Table 1.	NPCC Budget	3
Table 2.	Budget by Program Area	11
Table 3.	Total FTE's by Program Area	12
Table 4.	Budget and Current Year Projection Comparison	13
Table A-1.	Reliability Standards Budget	15
Table A-2.	Reliability Standards Budget Detail	24
Table A-3.	Compliance Monitoring and Enforcement and Organization Registration and Certification Budget	25
Table A-4.	Compliance Monitoring and Enforcement and Organization Registration and Certification Budget Detail	32
Table A-5.	Reliability Assessments and Performance Analysis (RAPA) Budget	33
Table A-6.	Reliability Assessments and Performance Analysis (RAPA) Budget Detail	49
Table A-7.	Training, Education, and Operator Certification Budget	50
Table A-8.	Training, Education, and Operator Certification Budget Detail	53
Table A-9.	Situation Awareness and Infrastructure Security Budget	54
Table A-10.	Situation Awareness and Infrastructure Security Budget Detail	59
Table A-11.	Administrative Services Budget	60
Table A-12.	Administrative Services Budget Detail	61
Table B-1.	Working Capital Reserve Analysis	72
Table B-2.	Penalty Sanctions Received	73
Table B-3.	Supplemental Funding	74
Table B-4.	Personnel Expenses	75
Table B-5.	Meeting Expense	76
Table B-6.	Consultants and Contracts	77
Table B-7.	Office Rent	77
Table B-8.	Office Costs	78
Table B-9.	Professional Services	79
Table B-10.	Miscellaneous	80
Table B-11.	Other Non-Operating Expenses	81
Table B-12.	Fixed Assets	82
Table B-13.	Three-Year Projections	84
Table C-1.	Criteria Services Division Business Plan and Budget	86
Table C-2.	Budget and Current Year Projection Comparison	92
Table C-3.	Personnel Analysis	93
Table C-4.	Reserve Analysis	94
Table D-1.	Statement of Financial Position, Three-Year Comparison	97