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 #19-2
May 15, 2019 10:00 a.m. – 4:00 p.m. EST
May 16, 2019 8:30 a.m. – 12:00 p.m. EST
Hampton Inn & Suites Saratoga Springs Downtown Hotel
25 Lake Avenue
Saratoga Springs, New York
Attire: Business Casual

Dial-In: 415-655-0003 (USA) / 416-915-6530 (Canada)

Day 1 - RSC Business:
Guest Code: 648097035
Password: zSkhH@53 (97544153 from phones)

Day 2 - DER Forum:
Guest Code: 643553113
Password: rHt9Rd@6 (74897316 from phones)

Day One RSC Business:

For Reference:
Glossary of Terms Used in NERC Reliability Standards, dated July 3, 2018
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 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 EPRI Report on HEMP
5.3 NERC SPIDER Work Group

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
Project 2017-01 Modifications to BAL-003-1.1	1/17/19 (F)	1/17/19 (I)
Project 2015-09 Establish and Communicate System Operating Limits	10/17/18 (F)	10/17/18 (I)
Project 2016-02 Modifications to CIP Standards	12/18/18 (I)	4/29/19 (F)
Project 2017-07 Standards Alignment with Registration	3/2/18 (F)	
Project 2018-03 Standards Efficiency Review Retirements	4/12/19 (F)	5/2/19 (F)
Project 2018-04 Modifications to PRC-024-2	5/31/19 (F)	5/31/19 (I)
Project 2019-01 Modifications to TPL-007-3	3/26/19 (I)	
Project 2019-02 BES Cyber System Information Access Management	4/26/19 (F)	
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 Standard status update.

9.0 NPCC Non-Standards

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

9.1 Items for Discussion:

9.1.1 Directory#7 *SPS* and NPCC Glossary term SPS
(Status of RAS Implementation/Transition)

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

9.1.3 Directory Manual --- Cost Effective Revisions
RSC Review of Open Process Comments. (Posting Closed Feb. 18, 2019)

9.1.4 BOD Approved Corporate Goal:
(Cost Effective Pilot ---- Directory #4 and Directory#5)
Status of Open Process Posting.

9.2 Executive Tracking Summary

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 23rd – Call	February 20th – Call	March 20th – Austin TX (Austin Energy)
April 17th – Call	May 22nd – Call	June 26th – Atlanta GA (NERC)
July 24th – Call	August 21st – Call	September 18th – Kansas City MO (KCP&L)
October 23rd – Call	November 20th – Call	December 18th – Atlanta GA (NERC)

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

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

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

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

February 6-7 - Meeting	May 8-9 - Meeting	August 14-15 - Meeting
November 5-6 - 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 has been no new NERC Alerts released since the last RSC meeting.

14.0 Other Items of Interest

14.1 NPCC Board of Directors Meeting (BOD) 2019

January 30th – ISO-NE Backup Control Center, Windsor CT	March 20th - Call	May 1st – NPCC Office
June 5th – Call	June 26th – NPCC Office	August 7th – Call
September 4th and 5th – Halifax, Nova Scotia	October 30th – Call	December 4th – Montreal, Quebec

14.2 NPCC and ERO 2020 Business Plan and Budget Schedule

15.0 Future RSC Meetings and Conference Calls

15.1 RSC 2019 Meeting Dates

February 13th-14th, Eversource, Boston MA
May 15th-16th, Saratoga NY
August 14th-15th, Toronto Canada August 7th-8th, Hydro One
October 16th-17th, Lewiston NY
December 5th, 2019 Montreal Canada (General Meeting)

Day Two DER Forum:

16.0 Distributed Energy Resources (DER) Forum Topics

16.1 BPS Reliability Implications of High Levels of Inverter-Based Resources – EPRI's Transmission Operations & Planning R&D Overview
16.2 NYISO Presentation on DER by James Pigeon
16.3 ITWG Presentation on 1547 and NY Interconnection of DER by George Smith
16.4 DPS Presentation on DER by Jason Pause
16.5 ISO-NE Presentation on DER by Dave Forrest
16.6 DER, Approach to Regional Guidance
16.7 Issues Raised by Stakeholders for Discussion and Approach to Resolution

Respectfully Submitted,

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

Northeast Power Coordinating Council, Inc. (NPCC)

Antitrust Compliance Guidelines

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

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

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

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

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

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

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NPCC REGIONAL STANDARDS COMMITTEE

AGENDA FOR MEETING #19-1
February 13, 2019 10:00 a.m. – 4:00 p.m. EST
February 14, 2019 8:30 a.m. – 12:00 p.m. EST
Eversource (NSTAR) Meeting Room C2002
1165 Massachusetts Avenue
Dorchester, Massachusetts
Attire: Business Casual

Dial-In: 415-655-0003 (USA) / 416-915-6530 (Canada)

Day 1:
Guest Code: 645909118
Password: pJJvp*23 (75587023 from phones)

Day 2:
Guest Code: 642745841
Password: SpXUH*93 (77984093 from phones)

For Reference:
Glossary of Terms Used in NERC Reliability Standards, dated July 3, 2018
NPCC Glossary of Terms, dated January 14, 2014

	Name	Organization	Sector (s)	Day(s)	Comment
1.	Guy Zito	Northeast Power Coordinating Council		1	
2.	Gerry Dunbar	Northeast Power Coordinating Council		1	
3.	Ruida Shu	Northeast Power Coordinating Council		1	
4.	Juan Villar	FERC	Guest	1	
5.	Howard Gugel	NERC	Guest	1	
6.	Chantal Mazza	Hydro Quebec	2	1	Via Phone
7	Herb Schrayshuen	Power Advisors, LLC - Proxy for NextEra Energy, LLC	4	1	Via Phone
8.	Chris Overberg	Consolidated Edison Co. of New York, Inc.	1, 3, 4 & 5	1	
9.	Constantin Chitescu	Ontario Power Generation, Inc.	4	1	
10.	Chris Moir	Ontario Power Generation, Inc.	Guest	1	
11.	Payam Farahbakhsh	Hydro One Networks	1	1	
12.	Ben Wu	Orange & Rockland Utilities, Inc.	3	1	
13.	Brian Robinson	Utility Services, Inc.	5	1	

14.	Sean Bodkin	Dominion Resources Services	4	1	Via Phone
15.	Helen Lainis	IESO	2	1	Via Phone
16.	Sean Lagan	IESO	Guest	1	
17.	Salvatore Spagnolo	NYPA	4	1	Via Phone
18.	Jim Grant	NYISO	2	1	
19.	Mike Jones	National Grid	3	1	
20.	David Kiguel	Independent	7	1	Via Phone
21.	Sean Cavote	PSEG	4	1	Via Phone
22.	Joel Charlebois	AESI	7	1	
23.	Mark Atkins	AESI	Guest	1	
24.	Quintin Lee	Eversource	1	1	
25.	Sharon Flannery	Eversource	1	1	
26.	Keith Jonassen	ISO-NE	Guest	1	
27.	Kathleen Goodman	ISO-NE	2	1	Via Phone
28.	Don Nelson	Commonwealth of Massachusetts DPU/EPD	Guest	1	
29.	Vijay Puran	New York State Department of Public Service	6	1	Via Phone
30.	David Burke	Orange & Rockland Utilities, Inc.	3	1	Via Phone
31.	Michele Tondalo	UI	1	1	Via Phone

Introductions and Chair's Remarks

- Guy Zito provided a summary on the potential goal for DER and mentioned the potential staff retirements at NPCC.
- Guy Zito provided a summary on NARUC, there are couple presentations on Micro-grid and IEEE 1471 DER interconnection requirements.
- IEEE is working on P2800 – ~~s~~Standard for Interconnection and Interoperability of Inverter-Based Resources Interconnecting with Associated Transmission Electric Power Systems. ~~which is~~ This standard establishes the recommended interconnection capability and performance criteria for inverter-based resources interconnected with transmission and networked sub-transmission systems. Included in this standard are recommendations on performance for reliable integration of inverter-based resources into the bulk power

system, including, but not limited to, voltage and frequency ride-through, active power control, reactive power control, dynamic active power support under abnormal frequency conditions, dynamic voltage support under abnormal voltage conditions, power quality, negative sequence current injection, and system protection.

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

Agenda Items:

1.0 Review of Agenda
Guy Zito reviewed the meeting agenda with the group.
Guy moved agenda item 5.3 to after 5.5.

2.0 RSC Meeting Minutes
Approval of Minutes—no additional revisions were made to the draft RSC meeting minutes of 12-6-18
Herb Schrayshuen made the motion for approval.
Jim Grant seconded the motion.
The meeting minutes were approved without modification~~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 made no additional changes.

3.2 NERC Project Tracking Spreadsheet
Guy Zito and Ruida Shu provided a brief update on the NERC Project Tracking Spreadsheet.

4.0 Open Action Items

4.1 Open Action Items List
The RSC member reviewed the open action item list which only had one item listed. The subgroup will review the RSPM by the end of the year.

5.0 Items Requiring RSC Discussion

5.1 NERC Weekly Standards Bulletin
Guy Zito reviewed the NERC weekly standards bulletin with the RSC group.

5.2 DER Forum and Approach to Guidelines
Action Item: RSC to send all distribution level DER interconnection information to Guy Zito.
Action Item: Herb Schrayshuen will send out information in regards to NYSRC in regards to DER.
SPIDER: System planning impact on DER working group at NERC.

5.3 National Grid Battery Project
Mike Jones from National Grid gave a presentation on Distributed Energy Resources Battery Energy Storage.

The battery energy storage units are being installed on the Nantucket island in Massachusetts. The issue is the growth of peak demand on the island of Nantucket.~~,~~ ~~i~~Instead of ~~bury~~adding another marine cable, National Grid decided to ~~put in~~install a 6MW Li-on Tesla Powerpack System, in addition to a new 15MW combustion turbine. The project will be in service in May 2019.

5.4 NPCC RSC Supply Chain Report

Guy Zito provided a presentation to the RSC members on FERC order #829 which is to develop a standard to address supply chain risk management. The standard must address the following: 1. Software integrity and authenticity; 2. Vendor remote access; 3. Information system planning; and 4. Vendor risk management and procurement controls.

The drafting team revised CIP-005-6, CIP-010-3 and created new CIP-013-1 standard.

A NERC Supply Chain Report is under development. The report will include recommendations for certain categories of assets not subject to the CIP supply chain standard(s).

The next step is to develop pre-audit surveys and questionnaires to help identify and assess industry practices, perform targeted outreach to vendors that support reliability of the BES, development of standardized vendor data sheets and independent testing of legacy applications and products. A section 1600 data request may be developed to collect information regarding Low Impact BES Cyber Systems.

5.5 Order 841 on Energy Storage

Guy Zito gave a presentation on FERC Order 841 Electric Storage Participation Markets Operated by Regional Transmission Organizations and Independent System Operators.

Concerns from the industry:

-NARUC concerns with FERC jurisdiction over wholesale markets that extend to the Distribution system.

-PJM reports that there are over 2GW of battery storage in the queue and industry concerned with their “10 hour” output requirement (same as their Hydro units~~s~~).

-Insufficient flexible to de-rate to optimize grid service.

-Some tariffs disallow dual participation for same resource in wholesale and retail markets.

-Municipals and Coops are concerns with wholesale DERs operating within their boundaries creating operational, safety and cost issues.

-Lifecycle of battery and degradation of performance.

-Lack of demonstrate capability when behind the meter-DMC testing?

-Maintenance requirements?

-20MW of residential solar and storage recently was cleared in forward capacity market.

-Observability-do we have situational awareness ~~o~~of what is on the system and be assured of its performance when needed? Dis-patchability?

-Cost recovery-tiered-proximity or benefit model?

5.6 NPCC 2019 BOD Approved Corporate Goals

Guy Zito reviewed the NPCC 2019 BOD approved corporate standard program area goals with everyone.

One of the main ~~task~~tasks is to develop a coordinated regional approach to reliability guidelines for interconnecting and operating distributed energy resources and create a forum under the RSC for DER reliability and interconnection issues~~s~~ and expanded coordination of technical requirements for ~~on~~ DERs with NAGF, FERC and NARUC efforts.

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
Project 2017-01 Modifications to BAL-003-1.1	1/17/19 (F)	1/17/19 (I)
Project 2015-09 Establish and Communicate System Operating Limits	10/17/18 (F)	10/17/18 (I)
Project 2016-02 Modifications to CIP Standards	12/18/18 (I)	10/9/18 (F)
Project 2017-03 FAC-008-3 Periodic Review	12/13/17 (F)	
Project 2017-07 Standards Alignment with Registration	3/2/18 (F)	
Project 2018-01 Canadian-specific Revisions to TPL-007-2	11/15/18 (F)	12/10/18 (F)
Project 2018-02 Modifications to CIP-008 Cyber Security Incident Reporting	11/29/18 (F)	11/29/18 (A)
Project 2018-04 Modifications to PRC-024-2	1/18/19 (F)	
Standards Efficiency Review	9/26/18 (F)	
Comments: (I) – Informal; (F) – Formal; (N) – Nomination Period **Ballots:** (I) – Initial; (A) – Additional; (F) – Final		

Project 2017-01, Project 2018-4 and SER:
Guy Zito and Howard Gugel provided a status update on these projects.

Project 2015-09, Project 2017-03 and Project 2017-07:
These projects are all on hold based on the SER and other efforts.

Project 2018-01 and Project 2018-02:
These two standards are in the process of being filed with FERC for approval.

Project 2016-02:
The drafting team wanted to ~~separate~~ split the Virtualization technology into logical and virtual however due to the overwhelming comments submitted by the industry during the December

2018 comment period the drafting team is taking a step and schedule a white board session to discuss virtualization and future technologies.
The drafting team is planning to develop a~~looking to~~ draft a white paper regarding ~~for the industry to review on~~ Virtualization and future technologies.

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 PRC-006-NPCC-2 Automatic Underfrequency Load Shedding Standard status update.
Ruida Shu reviewed the status of PRC-006-NPCC-2 with the RSC members. A ballot was conducted which opened on December 12, 2018 and closed on February 10, 2019.
Quorum: 80.95% of the total registered NPCC General and Full Members Representatives with Approval of 76%.
The plan is to send~~t~~ the standard to NPCC BOD for their approval consideration on May 1, 2019. Contingent upon the approval of the NPCC BOD, the proposal to approve PRC-006-NPCC-~~0~~2 will be submitted to the NERC Board of Trustees for their consideration and adoption at their August 14-15, 2019 meeting. NERC and NPCC will then develop filings for the FERC and applicable provincial authorities for their review and final approval.

9.0 NPCC Non-Standards
https://www.npcc.org/Standards/SitePages/NonStandardsList.aspx

9.1 Items for Discussion:
9.1.1 Directory#7 *SPS* and NPCC Glossary term SPS
(Status of RAS Implementation/Transition)

The TFCP is proposing revisions to Directory 7 Appendix B *Procedure for the Review of a Special Protection System* in order to conform the NPCC SPS review process to the provisions of PRC -012-2.

TFCP is coordinating these revisions with TFSS and TFSP.

Pending agreement on revisions the Appendix B will be appended to a revised version of Directory 7 and posted for Member comment.

TFSP anticipates posting Directory #7 mid 2019.

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

In accordance with the recommendations of the Phase 2 Final Report of the A-10 methodology, which was approved by the RCC at its December 5, 2018 meeting, CP-11 is currently incorporating the proposed improvements from the Final Report into a revised A-10 document.

CP-11 has been meeting via in person meetings and WEBEX's throughout the January and February 2019 time period and expects to present a preliminary version of the revised A-10 document to the TFCP in early April.

Subsequent to TFCP review an initial posting of the document for Member comment is anticipated in mid-May.

9.1.3 Directory Manual --- Cost Effective Revisions

In accordance with the recommendations of the *Strategic Review of the NPCC Criteria*, the RSC has proposed revisions to the Directory Manual that provide for cost effective considerations during the normal Task Force review of the criteria in each NPCC Directory. A revised version of the Directory Manual has been posted for comment until 2/18~~6~~/19 and the RSC will consider comments and propose additional revisions based on the comments received.

The RSC also agreed to review the results of the pending cost effectiveness surveys which are anticipated to be posted along with the revised versions of Directory *#4 System Protection Criteria* and Directory #5 *Reserve* by the TFSP and TFCO respectively.

9.1.4 BOD Approved Corporate Goal:

(Cost Effective Pilot ---- Directory #4 and Directory#5)
Action Item: RSC to review the Cost-Effective Pilot on Directory #4 and #5.

TFSP (D#4) and TFCO (D#5) anticipate posting ~~both~~ each Directory during the mid- March 2019 time period.

In accordance with the recommendations of the *Strategic Review of the NPCC Criteria* a cost-effective survey has been developed by each Task Force to accompany the postings.

The survey will solicit responses regarding the cost effectiveness and resilience contribution of the individual criteria attributes in order to assess whether there are alternative more cost--effective ways of achieving the same reliability outcome.

9.2 Executive Tracking Summary

Updates provided on the status of documents C-33 and proposed C-47.
C-33 *Procedure for Analysis and Classification of DCS* --- TFCP and TFSS considering a retirement recommendation for C-33 along with conforming changes to D#1 Appendix B.

C-47 *Event Replication Procedure* --- TFSS considering the establishment of an event replication document.

10.0 RSC Member Items of Interest

10.1 RSC Roster
Ruida Shu reviewed the RSC roster with the RSC group.

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

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http://www.nerc.com/comm/SC/Pages/default.aspx

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July 24th – Call	August 21st – Call	September 18th – Kansas City MO (KCP&L)
October 23rd – Call	November 20th – Call	December 18th – Atlanta GA (NERC)

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

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

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

12.5 Board of Trustees (BOT) Meeting
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February 6-7 - Meeting	May 8-9 - Meeting	August 14-15 - Meeting
November 5-6 - 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 three 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 no new NERC Alerts released since the last RSC meeting.

14.0 Other Items of Interest

14.1 NPCC Board of Directors Meeting (BOD) 2019

January 30th – ISO-NE Backup Control Center, Windsor CT	March 20th - Call	May 1st – NPCC Office
June 5th – Call	June 26th – NPCC Office	August 7th – Call
September 4th and 5th – Halifax, Nova Scotia	October 30th – Call	December 4th – Montreal, Quebec

14.2 NPCC and ERO 2020 Business Plan and Budget Schedule

15.0 Future RSC Meetings and Conference Calls

15.1 RSC 2019 Meeting Dates

February 13th-14th, Eversource, Boston MA
May 15th-16th, Saratoga NY
August 14th-15th, Toronto Canada
October 16th-17th, Lewiston NY
December 5th, 2019 Montreal Canada (General Meeting)

The meeting is adjourned at 4:21PM on February 13, 2019.

Respectfully Submitted,

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

Northeast Power Coordinating Council, Inc. (NPCC)

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- 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;
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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**
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	Dominion Resource Services, Inc.		
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	Jessica Tang	IESO		
2017-07	Standards Alignment with Registration	Standard	Mark Atkins	AESI		
2018-01	Canadian-specific Revisions to TPL-007-2	Standard	Majid Fassi Fehri Louis Gibson Steve Burns Cynthia Yiu Phillip Hiusser	Hydro Quebec Hydro Quebec IESO Hydro One OPG		
2018-02	2018-02 Modifications to CIP-008 Cyber Security Incident Reporting	Standard	Norm Dang Steve Brian	IESO Dominion Resource Services, Inc.		
2018-04	Modifications to PRC-024-2	Standard	Noel Aubut Tracy Macnicoll	Hydro Quebec Utility Services		
SER	Standard Efficiency Review	Standard	Greg Campoli (Advisers) Michael Puscus (Advisers)	NYISO ISO-NE		
2019-01	Modifictions to TPL-007-3	Standard	Per-Anders Lof (Vice Chair) Rui Sun Jow Ortiz Cynthia Yiu	National Grid Dominion Florida Power & Light (NextEra Energy) Hydro One		
Source = NERC Standard Drafting Team Rosters - July 2017						

RSC Meeting #19-2, Agenda Item 4.0 Open Action Items

Item	Description	Owner	Due	Status
4.1	Mike Jones, Quintin and Herb Schrayshuen volunteered to assist Guy Zito and Ruida Shu on reviewing the NPCC RSPM	Guy Zito Ruida Shu (The Pen)	By end of 2019	Pending
4.2	RSC to send all distribution level DER interconnection contact information to Guy Zito	Guy Zito	By end of 2019	Pending
4.3	Herb Schrayshuen will send out information in regards to NYSRC in regards to DER.	Herb Schrayshuen	By May 2019 RSC	Pending
4.4	RSC to review the Cost-Effective Pilot on Directory #4 and #5.	RSC	During the May 2019 RSC Meeting	Pending

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Standards, Compliance, and Enforcement Bulletin

May 6–12, 2019

INSIDE THIS EDITION

Active Standards Postings | Other Active Comment Periods | Standards News | General Compliance and Enforcement News | Other News | Standards Subject to Future Enforcement | Board of Trustees and FERC Action | Upcoming Events | About the SC&E Bulletin

ACTIVE STANDARDS POSTINGS

Current and Upcoming Ballots (ballot periods close at 8:00 p.m. Eastern)			
Project	**Action**	**Start Date**	**End Date**
Project 2018-04 – Modifications to PRC-024-2 | PRC-024-3	Initial Ballot and Non-binding Poll	05/22/19	05/31/19
Project	**Action**	**Start Date**	**End Date**
Project 2018-04 – Modifications to PRC-024-2 | PRC-024-3	Join Ballot Pools	04/17/19	05/16/19
Posted for Comment			
Project	**Action**	**Start Date**	**End Date**
Project 2018-04 – Modifications to PRC-024-2 | PRC-024-3	Comment Period	04/17/19	05/31/19

OTHER ACTIVE COMMENT PERIODS

Posted for Comment			
Posting	**Action**	**Start Date**	**End Date**
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STANDARDS NEWS

NEW Resources Posted

The slide presentation and streaming webinar for the April 18, 2019 Project 2018-04 – Modifications to PRC-024-2 webinar have been posted.

Quick Links

- Register in the SBS
- Projected Standards Posting Schedule
- Project Tracking Spreadsheet
- Standards Related Questions – Single Portal
- 2017–2019 Reliability Standards Development Plan
- Quality Review Application
- One-Stop Shop (Status, Purpose, Implementation Plans, FERC Orders, RSAWs)

GENERAL COMPLIANCE AND ENFORCEMENT NEWS

NEW Reliability Standard Audit Worksheets Posted

Two new Reliability Standard Audit Worksheets (RSAWs) are now available on the RSAW page of NERC.com under the heading "Current RSAWs for Use."

- PER-003-2 – Operating Personnel Credentials applies to Balancing Authorities, Reliability Coordinators, and Transmission Operators. The standard becomes effective July 1, 2019.
- TPL-007-3 – Transmission System Planned Performance for Geomagnetic Disturbance Events applies to Generator Owners, Planning Coordinators, Transmission Owners, and Transmission Planners. TPL-007-3 adds a variance for Canadian entities. It becomes effective July 1,

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
- Align Project (formerly CMEP Technology Project)

2019.Under the terms of the TPL-007-3 implementation plan, TPL-007-3 will supersede TPL-007-2 in the United States. All phased-in compliance dates are carried forward unchanged.

NEW Update on Centralized Organization Registration ERO System Project

The Centralized Organization Registration ERO System (CORES) Technology Project is progressing according to plan and is scheduled to launch in June 2019. A FAQ document has been posted to the CORES project page.

CORES, which combines the registration functions currently managed in OATI – webCDMS, Guidance – CITS, and CRATS into a consolidated registration system, is anticipated to be launched the week of June 17th, 2019, with multiple training opportunities to be provided by the ERO. If you would like more information about the project, please contact Ryan Stewart, senior manager of Registration and Certification.

OTHER NEWS

NEW NERC News Posted

NERC News, NERC's monthly newsletter, is now available for April. Highlights in this edition include:

- ERO Executive Spotlight Features Bill Lawrence, Vice President, Chief Security Officer and Director of the E-ISAC
- Statement on FERC's Open Meeting
- Robb Encourages Stakeholders to Participate in GridEx
- Align Release 1 Functionality and Training Schedule Released
- Regional Entity Updates
- Upcoming Events

STANDARDS SUBJECT TO FUTURE ENFORCEMENT

Please refer to the U.S. Effective Dates page for more detail on the standards listed below.

U.S. Effective Dates for Reliability Standards	
U.S. Effective Date	**Standard(s)**
July 1, 2019	PER-003-2 – Operating Personnel Credentials
	TPL-007-3 – Transmission System Planned Performance for Geomagnetic Disturbance Events (Requirements R1 and R2)

January 1, 2020	CIP-003-7 – Cyber Security — Security Management Controls
	PRC-026-1 – Relay Performance During Stable Power Swings (Requirements R2–R4)
	TPL-007-3 – Transmission System Planned Performance for Geomagnetic Disturbance Events (Requirements R5, 5.1, 5.2, R9, 9.1, and 9.2)
July 1, 2020	CIP-005-6 – Cyber Security – Electronic Security Perimeter(s) CIP-010-3 – Cyber Security — Configuration Change Management and Vulnerability Assessments CIP-013-1 – Cyber Security — Supply Chain Risk Management
	PRC-002-2 – Disturbance Monitoring and Reporting Requirements (50% compliance for Requirements R2–R4, R6–R11)
October 1, 2020	PER-006-1 – Specific Training for Personnel
	PRC-027-1 – Coordination of Protection Systems for Performance During Faults
January 1, 2021	PRC-012-2 – Remedial Action Schemes
July 1, 2021	TPL-007-3 – Transmission System Planned Performance for Geomagnetic Disturbance Events (Requirements R11 and R12)
January 1, 2022	TPL-007-3 – Transmission System Planned Performance for Geomagnetic Disturbance Events (Requirements R6, 6.1–6.4, R10, 10.1–10.4)
July 1, 2022	PRC-002-2 – Disturbance Monitoring and Reporting Requirements (100% compliance for Requirements R2–R4, R6–R11)
January 1, 2023	TPL-007-3 – Transmission System Planned Performance for Geomagnetic Disturbance Events (Requirements R3, R4, 4.1. 4.1.1–4.1.2, 4.2, 4.3, 4.3.1, R8, 8.1, 8.1.1–8.1.2, 8.3, 8.4, and 8.4.1)
January 1, 2024	TPL-007-3 – Transmission System Planned Performance for Geomagnetic Disturbance Events (Requirements R7, 7.1, 7.2, 7.3, 7.3.1–7.3.2, 7.4, 7.4.1–7.4.3, 7.5, and 7.5.1.)

BOARD OF TRUSTEES AND FERC ACTION

UPDATED NERC Board of Trustees Meeting Agenda Packages, Presentations, Policy Input, and Schedule of Events Posted

Agenda packages for the Board of Trustees, Member Representatives Committee, Corporate Governance and Human Resources Committee, and Technology and Security Committee meetings on May 8–9, 2019 in St. Louis, MO are now available. **NEW** The agenda package for the Finance and Audit Committee also contains the presentations. The schedule of events and policy input document are also available.

NEW Presentations for the Board of Trustees, Member Representatives Committee, Corporate Governance and Human Resources Committee, and Technology and Security Committee meetings are now available.

NEW FERC Approves Petition for FRCC RE Dissolution Actions

NERC is pleased with FERC's order approving the termination of the Regional Delegation Agreement between NERC and Florida Reliability Coordinating Council, Inc. (FRCC), as well as the transfer of registered entities within FRCC to SERC and the revisions to SERC's Regional Delegation Amendment reflecting their changed geographic footprint.

NERC appreciates FERC's prompt action and will continue to work with the Regional Entities and affected registered entities toward a seamless transition, expected to occur on July 1, 2019, with FRCC ceasing operations as a Regional Entity on August 31, 2019. For more information, please see SERC's FRCC transition page.

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

- NERC–NATF–EPRI 2019 Power System Modeling Conference Workshop – June 18–19, 2019, Novi, MI | Register
- 2019 Industry Standards and Compliance Workshop – July 23–24, 2019, Minneapolis, MN | In-person Registration | Webinar Registration | Hotel Registration

Webinars

There are no webinars currently scheduled.

Standing Committee Meetings and Conference Calls

- Board of Trustees, Board Committees, and Member Representatives Committee Meetings – May 8–9, 2019, St. Louis, MO | Register
- NEW Standards Committee Conference Call – 1:00–3:00 p.m. Eastern, May 22, 2019 | Register
- Operating Committee, Planning Committee, and Critical Infrastructure Protection Committee Meetings – June 4–5, 2019, Orlando, FL | Register for OC | Register for PC | Register for CIPC | Register for Hotel
- Compliance and Certification Committee Meeting – June 18–19, 2019, Chicago | **Registration Details Coming Soon**

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.

- Standards Efficiency Review - Phase 2 Conference Call – 11:00 a.m.–12:30 p.m. Eastern, May 13, 2019 | Register
- **NEW** Project 2019-01 – Modifications to TPL-007-3 Conference Call – 11:00 a.m.–Noon Eastern, May 15, 2019 | Register
- Project 2016-02 – Modifications to CIP Standards Drafting Team Meeting – May 21–23, 2019, Taylor, TX | Register
- **NEW** Project 2019-01 – Modifications to TPL-007-3 – June 4–5, 2019, Atlanta | Register
- Project 2018-04 – Modifications to PRC-024-2 Meeting – June 18–20, 2019, Montreal, Quebec | Register

ABOUT THE STANDARDS, COMPLIANCE, AND ENFORCEMENT BULLETIN

This weekly bulletin compiles a list of standards, compliance, and enforcement 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 project, please submit a ticket through the Help Desk. Select the "NERC Email Distribution List" option under the "Applications" menu. In the Description Box, please specify which lists you would like your email address to be added to or note which announcements you would like to receive. This bulletin is distributed to several lists, including the Standards distro list (Standards-specific announcements) and the NERC-info distro list (most NERC announcements).

Regional Standards Committee

May 15-16, 2019

High-Altitude Electromagnetic Pulse and the Bulk Power System

Guy V. Zito

NPCC AVP - Standards

Discussion Items:

- High altitude Electromagnetic Pulse (HEMP) what is it?
- Executive Order on EMP
- EPRI Report
- Next Steps

HEMP- What is it?

- Nuclear detonation at altitude, EMPs may also be generated at ground and at lower levels for more local effects
- Three components of a HEMP E1, E2, and E3
- The E1 component is a very brief but intense electromagnetic field that can quickly induce very high voltages in electrical conductors. 50 kv/m, 2.5 nanosec rise. Most destructive.
- The E2 and E3 generally well understood; E2 similar to lightning and E3 similar to GMD. Starfish Prime studies in 1962. E3 understanding resulted in revision to TPL-007 and supplemental analysis-increase in the studied electric field.
- Creates an artificial radiation belt (Satellite risk)

HEMP – High Impact Low Frequency Risk

- Electric Power Research Institute EPRI Study of E1
  - Study released and public - April 30, 2019
  - Study used wave guides and direct injection in simulations
  - Study recommends mitigation methods to harden the grid against HEMP effects
- FERC
  - Evaluating study results
  - Potential for a NOPR to address possible BES E1 risks
  - Potential for a similar approach as GMD, one for operational and one for planning (i.e. EOP-010 and TPL-007)
  - Critical facility list development identifying where potential weaknesses may exist

HEMP – High Impact Low Frequency Risk

- Executive Order, March 26, 2019

  Coordinating National Resilience to Electromagnetic Pulses

  - Update all U.S. Federal Plans to recognize EMP
  - Identify critical infrastructure (public health and safety)
  - Identify infrastructure most vulnerable to EMP
  - Review existing standards, identify gaps
  - Conduct a magnetotelleuric survey (within 4 years)
  - Analyze technology options and test them
  - Report cost effective approaches to President
- Critical Path to an EMP Plan- Section 6 “Implementation” (biii)-1 year+(cii) 180 days+(di)90 days = 1 year and 9 months from date of Order

EPRI Report- What's in it?

- Substation Equipment tested for vulnerability
  - Free field illumination testing (EM Plane Wave-Transient EM Field)
  - Direct Injection Testing (Voltage Impulse Testing)
  - Shielding Effectiveness Testing
- Assessment of Impact
- Approaches for Mitigating Impact
- Recovery following a HEMP (Resilience)
- Recommendations

EPRI Report- Conclusions

- Digital Protective Relays susceptible to E1 conducted Transients
- Tests inconclusive but indicated E1 **not** found to cause immediate, interconnection-scale disruption or blackout of the power grid
- Existing lighting protection sufficient for E2 protection with 100kv/m threat level
- E3 EMP alone could result in a regional blackout encompassing multiple states, but immediate, widespread transformer damage due to hotspot heating from part-cycle saturation is not expected to occur.

EPRI Report- Conclusions

- Mitigating Risk for an E1
  - Shielded control/signal cables with proper grounding
  - Use of fiber optics based communications and protection and control systems
  - Modifications to substation control houses to enhance electromagnetic shielding properties
  - Grounding/bonding enhancements
  - Additional sparing of critical assets such as DPRs, SCADA, and communications equipment
- No additional mitigation needed for E2 risk

EPRI Report- Conclusions

- Mitigating Risk for E3
  - Modify protection and control schemes for resilience to harmonics and system imbalance
  - Blocking or reducing the flow of geomagnetically induced currents (GICs)
  - Automatic removal of some shunt reactive power compensation devices, for example shunt reactors, and/or employing under-voltage load shedding (UVLS)
  - Sparing of large power transformers and high-voltage circuit breakers

EPRI Report- Conclusions

- System Recovery from an EMP assumptions
  - Unavailable/inoperable/damaged equipment along the cranking paths
  - Impaired levels of situational awareness (including observability and controllability)
  - Inability to notify, or difficulty in notifying, key response personnel
- Observations of EPRI for recovery from EMP
  - Restoration strategies may need to be revised to focus on less damaged portions of the system
  - Step by step energization procedures may not be practical
  - Study alternative cranking paths
  - Additional personnel training for HEMP induced blackout and system recovery would be beneficial

Possible Next Steps-

FERC

- Evaluating study results
- Potential for a NOPR to address possible BES E1 risks and need for standards
- Potential for a similar approach as GMD, one for operational and one for planning (i.e. EOP-010 and TPL-007)
- Critical facility list development identifying where potential weaknesses may exist

ERO Enterprise- NERC and Regions

- Promote awareness of HILF HEMP and EMP
- Develop guidance
- Adjust System restoration and training
- Coordinate with DHS and DOE on Executive Order
- Identify and assist with potential mitigation activities and cost effectiveness analysis

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standard Authorization Request (SAR)

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:	MOD-032-1 Data for Power System Modeling and Analysis		
Date Submitted:	__/__/2019		
SAR Requester			
Name:	Jeff Billinton (NERC SPIDERWG Chair) Bill Quaintance (NERC SPIDERWG Vice Chair)		
Organization:	Jeff Billinton – California ISO Bill Quaintance – Duke Energy Progress		
Telephone:	Jeff – 916-608-7126 Bill – 919-546-4810	Email:	jbillinton@caiso.com william.quaintance@duke-energy.com

SAR Type (Check as many as apply)	
☐ New Standard	☐ Imminent Action/ Confidential Issue (SPM Section 10)
☒ Revision to Existing Standard	☐ Variance development or revision
☐ Add, Modify or Retire a Glossary Term	☐ Other (Please specify)
☐ Withdraw/retire an Existing Standard	

Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)	
☐ Regulatory Initiation	☒ NERC Standing Committee Identified
☒ Emerging Risk (Reliability Issues Steering Committee) Identified	☐ Enhanced Periodic Review Initiated
☐ Reliability Standard Development Plan	☒ Industry Stakeholder Identified

Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):

As the penetration of distributed energy resources (DER) continues to increase across the North American bulk power system (BPS), it will be necessary for some NERC Reliability Standards to be updated to account for DER in the planning, operation, and design of the BPS. The NERC System Planning Impacts of Distributed Energy Resources Working Group (SPIDERWG) has identified the need for improved modeling of DER for planning studies. MOD-032-1 addresses the gathering of modeling data to build interconnection-wide base cases for the planning horizon but the standard currently has no provisions regarding DER data. This SAR proposes to update MOD-032-1 to: (1) include data requirements and reporting procedures for DER that are necessary to support the development of accurate interconnection-wide models, (2) replace Load-Serving Entity (LSE) with Distribution Provider (DP) because of the removal of LSEs from the NERC registry criteria, and (3) reflect the current NERC template for Reliability Standards.

Requested information

Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):

This SAR proposes to revise MOD-032-1 to address gaps in data collection for the purposes of modeling and interconnection-wide case creation regarding DER. The goal is to provide clarity and consistency for data collection across Planning Coordinators (PCs) and Transmission Planners (TPs) when coordinating with the DP to gather load and DER data.

Project Scope (Define the parameters of the proposed project):

The proposed scope of this project is as follows:

a. In alignment with the SAR submitted by the NERC ERSWG, LSE should be removed and replaced by DP as the applicable entity in Section 4.1.3 and all instances in the standard requirements and attachments.

b. The table in Attachment 1 should be updated to include DER in the steady-state, dynamics, and short circuit columns. Details of the changes to be considered by the Standard Drafting Team are included in the "Detailed Description" below.

c. Based on item b.) and the detailed description below, the SDT should consider whether including a definition for "Distributed Energy Resource (DER)" in the NERC Glossary of Terms is necessary.

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 SAR proposes to address the issues identified in the project scope above. Specifically, the following details should be considered and addressed by the drafting team:

- In the Applicability section of MOD-032-1, LSE should be replaced with DP, in alignment with the SAR previously submitted by ERSWG. Similarly, all relevant uses of LSE should be replaced with DP.
- The table in Attachment 1 should include references to aggregate DER in the steady-state and dynamics columns. The drafting team should consider the data needed for modeling aggregate DER for the purposes of BPS reliability studies. However, the NERC SPIDERWG proposes that the SDT consider including, at a minimum, the following information in the table:
    - Steady-State:
        - Aggregate Distributed Energy Resources
            - Aggregate maximum and minimum active power capacity
            - Location (correlated to BPS bus location)

[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
- Breakdown by type of DER (e.g., by fuel type or technology)   o Dynamics: - Aggregate Distributed Energy Resources   - Note that the SPIDERWG does not see a need to modify the short circuit column of Attachment 1 because #1 already states “all applicable elements” in the steady-state column should have necessary information related to positive, negative, and zero sequence data provided accordingly.   - In alignment with adding “DER” to the Attachment 1 table regarding necessary data for modeling purposes, it may be needed (based on the discretion of the SDT) to add a definition for “Distributed Energy Resource (DER)” to the NERC Glossary of Terms.   The SPIDERWG is in the process of developing recommended practices and NERC Reliability Guidelines related to data collection for DER modeling. These materials will provide more detailed guidance for TPs and PCs to develop their data requirements and reporting procedures, per MOD-032-1. The SDT should use these materials, as they become available, when determining the specific language for inclusion in the standard requirements revisions.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
Cost impacts are not fully known. However, due to the limited scope of the requested data, cost impact should be minimal to all entities. DPs typically collect the maximum capacity and location of DER connected to their systems during the interconnection process. Therefore, data collection effort by the DP would be minimal additional effort. DPs already have processes to provide load data to the TP and PC, so DER data can be managed in a similar manner to reduce cost and effort. If the scope of the required data is expanded, cost impact would likely increase.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g*. Dispersed Generation Resources):
DER owners are not subject to NERC Reliability Standards. However, the DP (a NERC Registered Entity) has the information regarding DER connected to their distribution system that is needed for modeling the aggregate behavior of DER for the purposes of planning studies. The DP should provide that information to the TP and PC accordingly.
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):
Transmission Planner, Planning Coordinator, Distribution Provider While not a Functional Entity per the NERC Functional Model, the “MOD-032 Designees” that are designated by the ERO to develop interconnection-wide base cases (i.e., the Regional Entities), will also be affected by these changes and should be considered for appointment to the Standard Drafting Team.

Requested information
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.
The proposals in this SAR were developed by the NERC SPIDERWG, a stakeholder group under the NERC Planning Committee.
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)?
The ERSWG submitted a SAR related to MOD-032-1, as described above. This SAR supports those changes, and further expands on a few necessary additional changes related to DER modeling.
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.
The NERC SPIDERWG is preparing a Reliability Guideline on data collection for DER modeling. That guideline will provide recommendations for improvements to the data requirements and reporting procedures developed jointly by PCs and their TPs. However, updates to MOD-032-1 are also needed to capture the types of information needed regarding DER, particularly in Attachment 1. Therefore, this SAR aligns with the necessary changes to meet the objective.

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.

[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.

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
None	None

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 18, 2017	Standards Information Staff	Revised
2	June 28, 2017	Standards Information Staff	Updated template

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Guideline

Parameterization of the DER_A Model

March 2019

RELIABILITY | ACCOUNTABILITY

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Atlanta, GA 30326
404-446-2560 | www.nerc.com

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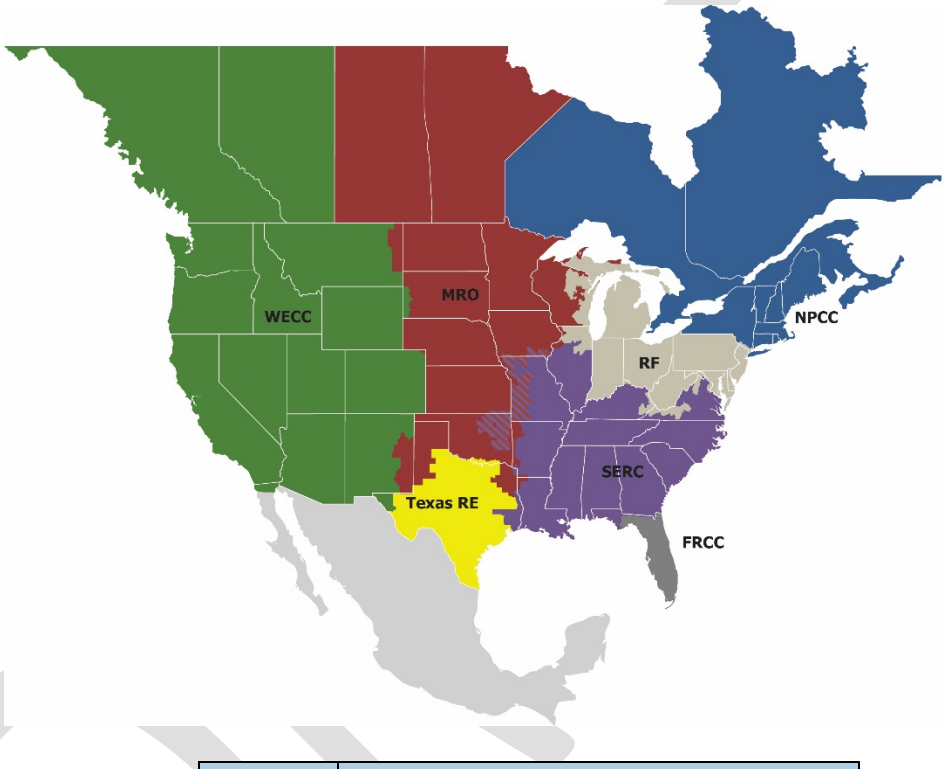
Preface

The vision for the Electric Reliability Organization (ERO) Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the seven Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

The North American BPS is divided into seven RE boundaries as shown in the map and corresponding table below. The multicolored area denotes 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
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Executive Summary

The NERC Load Modeling Task Force (LMTF)[1] worked in coordination with the NERC DERTF, and published two detailed guidelines on modeling distributed energy resources (DERs) as either stand-alone generating resources or as part of the composite load model. The Reliability Guideline: Modeling DER in Dynamic Load Models, published in December 2016, established a framework for modeling DER in steady-state powerflow and dynamic simulations. The Reliability Guideline: Distributed Energy Resource Modeling, published in September 2017, utilized the framework established in the preceding guideline, and provided default parameter values for various DER dynamic models. At the time of development of that guideline, the *DER_A* model was still under development and was therefore only briefly mentioned.

With the *DER_A* model now implemented and tested across the major commercial software vendors, this guideline provides background and guidance on parameterizing the *DER_A* model for representing aggregate or stand-alone inverter-based DER resources in stability studies. The guideline provides background material on the recommended modeling framework, including the concepts of retail-scale DER (R-DER) and utility-scale DER (U-DER), information on relevant interconnection standards (IEEE Std. 1547-2003, IEEE Std. 1547a-2014, IEEE Std. 1547-2018, and CA Rule 21), and how the *DER_A* model parameters can be modified to account for a mixture of vintages of inverter-interfaced DER.

The guideline is intended for use by Planning Coordinators, Transmission Planners, Transmission Operators, Reliability Coordinators, and other entities performing positive sequence stability simulations of the bulk power system where an aggregate representation of DER is needed. It also serves as a useful reference for building DER models and selecting representative DER model parameters in situations where more detailed information is not yet available.

DRAFT

[1] https://www.nerc.com/comm/PC/Pages/Load%20Modeling%20Task%20Force%20(LMTF)/Load-Modeling-Task-Force.aspx.

Introduction

The NERC Distributed Energy Resources Task Force (DERTF) published a report[2] in February 2017 focusing on connection modeling and reliability considerations for DER. The report provided definitions of DER, an overview of data and modeling needs, characteristics of nonsynchronous DER, and potential reliability impacts of DER to the bulk power system (BPS).

The NERC Load Modeling Task Force (LMTF)[3] worked in coordination with the NERC DERTF, and published two detailed guidelines on modeling distributed energy resources (DERs) as either stand-alone generating resources or as part of the composite load model (CLM). The Reliability Guideline: Modeling DER in Dynamic Load Models, published in December 2016, established a framework for modeling DER in steady-state powerflow and dynamic simulations. The Reliability Guideline: Distributed Energy Resource Modeling, published in September 2017, utilized the framework established in the preceding guideline, and provided default parameter values for various DER dynamic models. At the time of development of that guideline, the *DER_A* model was still under development and testing and was therefore only briefly mentioned. With the *DER_A* model now implemented and tested across the major commercial software vendors, this guideline provides background and guidance on parameterizing the *DER_A* model for representing aggregate or stand-alone inverter-baseed DER resources.

The following sub-section briefly describes the DER modeling framework, and the definitions and terminology used in that framework. Refer to the modeling guidelines for more details.

DER Modeling Framework

For the purposes of steady-state and dynamic modeling of DER in BPS reliability studies, DER can be defined as either utility-scale DER (U-DER) or retail-scale DER (R-DER), which the previous guidelines have defined as:

- **Utility-Scale Distributed Energy Resources (U-DER):** DER directly connected to, or closely connected to, the distribution bus[4] or connected to the distribution bus through a dedicated, non-load serving feeder. These resources are typically three-phase interconnections, and can range in capacity (e.g., 0.5 to 20 MW).
- **Retail-Scale Distributed Energy Resources (R-DER):** DER that offsets customer load, including residential[5], commercial, and industrial customers.[6] Typically, the residential units are single-phase while the commercial and industrial units can be single- or three-phase facilities.[7]

U-DER are typically relatively large, stand-alone installations that may have more complex controls or requirements associated with their interconnection. R-DER represents the truly distributed resources throughout the distribution system whose controls are generally reflective of IEEE Std. 1547[8] vintages or other relevant requirements for the

[2] https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy_Resources_Report.pdf.
[3] https://www.nerc.com/comm/PC/Pages/Load%20Modeling%20Task%20Force%20(LMTF)/Load-Modeling-Task-Force.aspx.
[4] The distribution bus is connected to a transmission voltage bus via the transmission-distribution transformer. Resources not directly connected to this bus do not meet the criteria for this definition.
[5] This also applies to community DER that do not serve any load directly but are interconnected directly to a distribution load serving feeder.
[6] This often includes behind the meter generation, but may also include individually metered DER and systems that export beyond customer load at a particular site boundary.
[7] For the purposes of modeling, some larger utility-scale U-DER may exist along the load-serving distribution feeder and may be electrically distant from the distribution substation. In these cases, they may be represented as R-DER since they offset customer load. The aggregate power output can potentially exceed the total load demand of the distribution feeder.
[8] IEEE Std. 1547-2003, Standard for Interconnecting Distributed Resources with Electric Power Systems, July 2003. Available: https://standards.ieee.org/standard/1547-2003.html.
IEEE Std. 1547a-2014, IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems – Amendment 1, May 2014. [Online]. Available: https://standards.ieee.org/standard/1547a-2014.html,
IEEE Std. 1547-2018, IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces, April 2018. [Online]. Available: https://standards.ieee.org/findstds/standard/1547-2018.html.

region they are being interconnected. Both U-DER and R-DER can be differentiated, and should be accounted for, in powerflow base cases and dynamic simulations. Modeling U-DER and R-DER in the powerflow provides an effective platform for linking this data to the dynamics records and ensuring that the dynamics of these resources are accounted for.

Transmission Planners (TPs) and Planning Coordinators (PCs), in conjunction with their Distribution Providers (DPs),[9] should identify thresholds where U-DER should be explicitly modeled and R-DER should be accounted for in the powerflow and dynamics cases. The thresholds should be based on either the individual or aggregate impact of DER on the BPS. [10]

- Gross aggregate nameplate rating of an individual U-DER facility directly connected to the distribution bus or interconnected to the distribution bus through a dedicated, non-load serving feeder; and
- Gross aggregate nameplate rating of all connected R-DER that offset customer load including residential, commercial, and industrial customers.

The thresholds for modeling U-DER and R-DER, determined based on engineering judgment, can be defined as:

- **U-DER Modeling:** Any individual U-DER facility rated at or higher than the defined threshold should be modeled explicitly in the powerflow case at the low-side of the transmission-distribution transformer. A dynamics record could be used to account for the transient behavior[11] of this plant. U-DER less than the defined threshold should be accounted for as an R-DER as described below. Multiple similar U-DER connected to the same substation low-side bus could be modeled as an aggregate resource as deemed suitable by the TP or PC.
- **R-DER Modeling:** If the gross aggregate nameplate rating of R-DER connected to a feeder exceeds this threshold, these DER should be accounted for in dynamic simulations as part of the dynamic load model. While this may not require any explicit model representation in the powerflow base case, the amount of R-DER can be accounted for as part of the powerflow load record and integrated into the dynamic model as an explicit DER component. The threshold for modeling R-DER should be 0 MVA, meaning that all forms of DER be accounted for (not netted with the load) to the extent possible.

Figure I.1 shows the recommended powerflow representation for accounting for U-DER. The left side of Figure I.1 shows the conventional powerflow representation of the load record. This has conventionally included both load and DER (representing a net load quantity as opposed to a gross load quantity). However, the right side of Figure I.1 shows how the transmission-distribution (T-D) transformer can be modeled explicitly and the gross load can be moved to the low side distribution bus. U-DER above the specified threshold can be modeled explicitly via its own step-up transformer, as applicable. If the U-DER is connected through a dedicated feeder or circuit to the low-side bus, then that would also be explicitly modeled in the powerflow.

IEEE Std. 1547-2018, 6/4/2018: Errata to IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces. Available online at http://standards.ieee.org/findstds/errata/1547-2018_errata.pdf.

[9] DPs should provide information to TPs and PCs to support the development of representative dynamic load models including information pertaining to DER. TPs and PCs should consider the cost impacts of requesting detailed information related to DER. In many cases, aggregate (or high-level) information pertaining to the DER vintage, for example, may be sufficient to develop a reasonable set of model parameters.

[10] This may include many different types of DER including distributed solar PV, energy storage, synchronous generation, and other types of DER. Including synchronous generation in the composite load model as a component of R-DER may not be possible across all software platforms.

[11] Depending on complexity of the actual U-DER, for inverter coupled U-DER, more sophisticated models such as the second generation generic renewable energy system models may also be used (i.e., *regc_a*, *reec_b* and *repc_a*). Other U-DER (e.g. synchronous gas or steam-turbine generators) can also be modeled using standard models available in commercial software platforms.

To capture the R-DER in the powerflow, the load records now[12] have the capability to input the R-DER quantity along with the gross load amount. Figure I.2 shows an example of the R-DER included in the powerflow load records. The red box shows the R-DER specified and the blue box shows the net load equal to the actual load less the R-DER. For example 80 MW and 20 MVar of actual load with 40 MW and 0 MVar of R-DER at Bus 2.

Once represented in the powerflow base case, data for the CLM can be modified to account for explicit representation of the DER and T-D transformer. Figure I.3 shows the dynamic representation of the CLM, where the distribution transformer impedance is not represented in the dynamic load record. Rather, it is modeled explicitly in the powerflow to accommodate one or more U-DER.[13] Any load tap changer (LTC) modeling[14] would be done outside the CLM such as enabling tap changing in the powerflow[15] and using the *ltc1* model in dynamic simulations. Motor load and the distribution equivalent are modeled as part of the CLM, and the R-DER are represented at the load bus based on the data entered in the load record table.

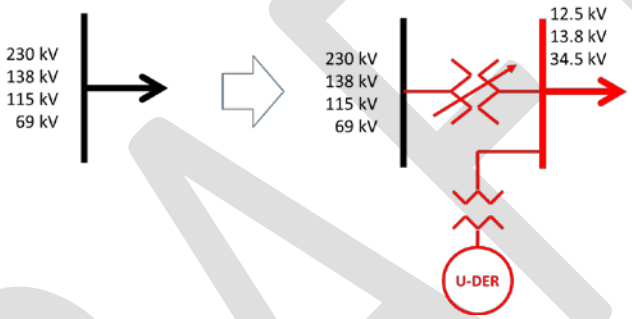


Figure I.1: Representing U-DER in the Powerflow Base Case

	Number of Bus	Name of Bus	Area Name of Load	Zone Name of Load	ID	Status	MW	Mvar	MVA	S MW	S Mvar	Dist Status	Dist MW Input	Dist Mvar Input	Dist MW	Dist Mvar	Net Mvar	Net MW
1	2	Two	Top	1	1	Closed	80.00	20.00	82.46	80.00	20.00	Closed	40.00	0.00	40.000	0.000	20.000	40.000
2	3	Three	Top	1	1	Closed	220.00	40.00	223.61	220.00	40.00	Open	110.00	0.00	0.000	0.000	40.000	220.000
3	4	Four	Top	1	1	Closed	160.00	30.00	162.79	160.00	30.00	Closed	80.00	0.00	80.000	0.000	30.000	80.000
4	5	Five	Top	1	1	Closed	260.00	40.00	263.06	260.00	40.00	Open	130.00	0.00	0.000	0.000	40.000	260.000
5	6	Six	Left	1	1	Closed	400.00	0.00	400.00	400.00	0.00	Closed	200.00	0.00	200.000	0.000	0.000	200.000
6	7	Seven	Right	1	1	Closed	400.00	0.00	400.00	400.00	0.00	Closed	200.00	0.00	200.000	0.000	0.000	200.000

Figure I.2: Capturing R-DER in the Powerflow Load Records [Source: PowerWorld]

[12] All commonly used commercial simulation software platforms now have, or are currently implementing, the ability to represent DER as part of the load record, in an attempt to standardize and unify modeling practices for representing DER in powerflow base cases.

[13] If only R-DER is represented at a bus (no U-DER), then the T-D transformer does not necessarily need to be explicitly modeled in the powerflow since it can be accounted for in the composite load model dynamic record, including LTC action. However, if LTC action needs to be modeled in the steady-state analyses in any way, then explicit modeling of the T-D transformer in the powerflow may be needed.

[14] Utilities using transformers without ULTC capability but with voltage regulators at the head of the feeder could model this in the CLM with a minimal transformer impedance but active LTC to represent the voltage regulator.

[15] For example, by specifying settings in the transformer record and enabling tap changing in the powerflow solution options.

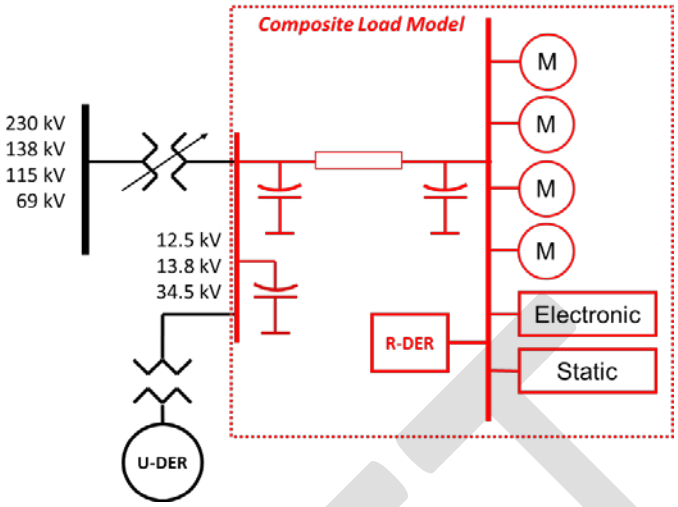


Figure I.3: Dynamic Load Model Representation with U-DER Represented in the Powerflow Base Case

Background and Overview of the DER_A Model

The *DER_A* model is a simplified version of the second generation generic renewable energy system models (i.e., *regc_a*, *reec_b*, *repc_a*, *lhvrt*, *lhfrt*) used to represent inverter-based DER (i.e., utility-scale wind, solar photovoltaic (PV), and battery energy storage resouces). The DER_A model uses a reduced set of parameters, meant to represent the aggregation of a large number of inverter-interfaced DERs. It is also an improvement over the *pvd1* model in that it includes additional modeling flexibility for more advanced and representative capabilities introduced in IEEE Std. 1547-2018 and California Rule 21. The *DER_A* model can be used to represent U-DER (individual DER resources, or a group of similar U-DERs), and can also be used to represent R-DER (as either a standalone DER dynamic model, or as part of the CLM). The *DER_A* model includes the following features:

- Constant power factor and constant reactive power control modes. Allows voltage control to be active along with PF/Q control, depending on whether voltage is within the deadband or not.
- Active power-frequency control with droop and asymmetric deadband.
- Voltage control with proportional control and asymmetric deadband (may be used to either represent steady-state voltage control or dynamic voltage support, depending on chosen time constants).
- Representation of a fraction of resources tripping or entering momentary cessation at low and high voltage, including a four-point piece-wise linear gain. The partial tripping includes a timer feature as well.
- Representation of a fraction of resources restoring output following a low or high voltage or frequency condition (representation of legacy trip and modern ride-through capabilities in a single model).
- Active power ramp rate limits during return to service after trip or enter service following a fault or during frequency response.
- Active-reactive current priority options (used to represent dynamic voltage support during fault events).
- Capability to represent generating or energy storage resources.[16] The model allows for absorption of active power; however, charging and discharging (as modeled in *reec_c*) is not included. Therefore, the *DER_A* model should not be used for devices with only a few seconds of energy injection (e.g., flywheel energy systems).

The overall block diagram for the *DER_A* model can be found in Appendix B.

[16] This guideline focuses mostly on using the *DER_A* model to represent generating resources, primarily distributed solar PV generation. However, the *DER_A* model can be used to represent energy storage, and future guidelines may be developed on this topic, as necessary.

Chapter 1: Annotated DER_A Block Diagram

This chapter briefly describes the functional sections of the *DER_A* model, and provides a high-level overview of what the various blocks represent. Refer to the *DER_A* specification document[17] for more detailed information regarding implementation. The sub-sections below describe the general control aspects of the different functional sections of the model.

Active Power-Frequency Controls

The active power-frequency controls portion of the *DER_A* model are shown in Figure 1.1. The frequency input signal feeding the active-power frequency controls is first passed through a frequency measurement time constant, *Trf*. The filtered voltage is compared against a reference signal. The *fdbd1* and *fdbd2* parameters represent the active power-frequency control deadband for overfrequency and underfrequency, respectively. The *Ddn* and *Dup* parameters represent the overfrequency and underfrequency droop gains, respectively. *Tp* represents an active power measurement time constant. When active power-frequency control is enabled, *Freq_flag* is set to 1. To disable active power-frequency control of the model, set *Freq_flag* to 0. The frequency error is limited by *femax* and *femin*, and goes through a PI controller with *Kpg* and *Kig* parameters. The *dPmax* and *dPmin* parameters limit active power upward and downward ramp rates. *Pmax* and *Pmin* represent the maximum and minimum power output, respectively. *Tpord* is the power-order time constant. It (*Tpord*) can be used to represent the small time lag for changing the power reference (when Freq_flag = 0), or the open-loop time constant associated with the full controls (when Freq_flag = 1), as specified in IEEE Std. 1547-2018. Active current command (*ipcmd*) is calculated using power-order (*Pord*) divided by filtered terminal voltage (*Vt_filt*), and is limited by *Ipmax* and *Ipmin*.

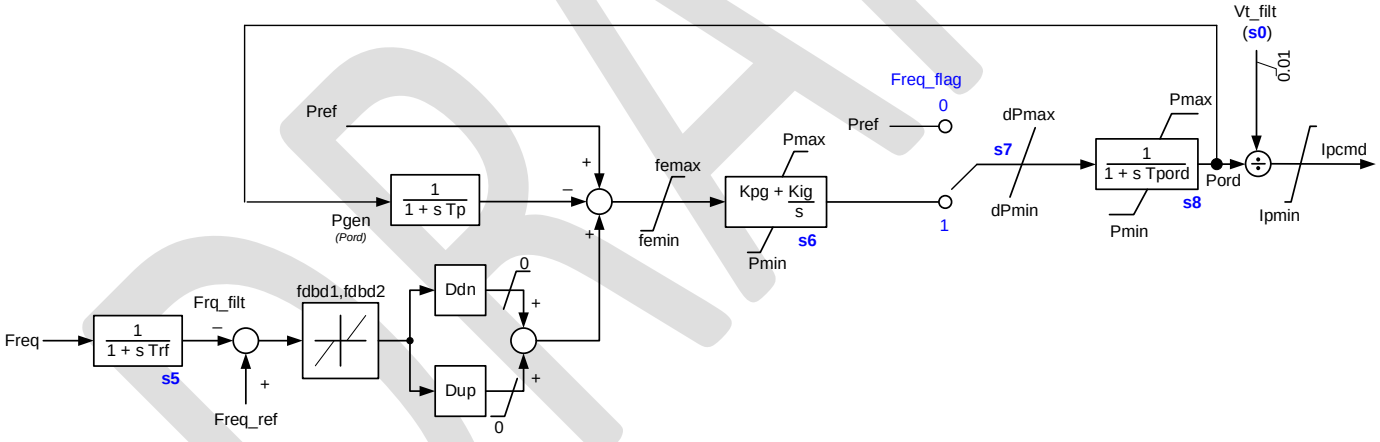


Figure 1.1: Active Power-Frequency Controls

Frequency Tripping Logic Input

The frequency input signal feeding the active-power frequency controls is first passed through a frequency measurement time constant, *Trf*. A low voltage inhibit logic was added to the model, which is shown in Figure 1.2. When voltage falls below a threshold (*Vpr*), then the frequency relay model is bypassed. This is common in frequency protective functions, to avoid any spurious tripping during transients. In numerical simulations, this low voltage inhibit is also used to avoid tripping on numerical spikes during discontinuities. This may not always work in positive sequence program simulations, as it is hard to predict the size of the spike and how long it will last after filtering.[18]

[17] P. Pourbeik, "Proposal for DER_A Model," September 11, 2018. [Online]. Available: https://www.wecc.biz/Reliability/DER_A_Final.pdf.
[18] https://www.wecc.biz/Reliability/WECC_White_Paper_Frequency_062618_Clean_Final.pdf

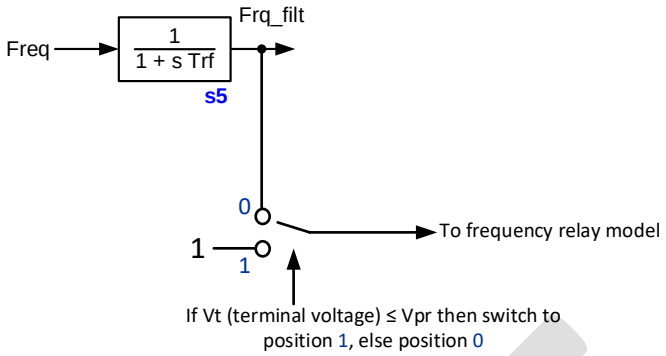


Figure 1.2: Frequency Tripping Logic Controls

Reactive Power-Voltage Controls

The reactive power-voltage controls portion of the *DER_A* model are shown in Figure 1.3. Setting *pflag* to 0 or 1 selects either constant reactive power control or constant power factor control, respectively. The *pfaref* parameter is internally calculated to achieve the necessary reactive power order for the current active power order. Reactive power is then divided by filtered terminal voltage (*Vt_filt*) and passed through a reactive current calculation time constant (*Tiq*). Voltage control is included in the model. Terminal voltage (*Vt*), after a measurement time constant (*Trv*), passes through a lower (*dbd1*) and upper (*dbd2*) deadband and proportional control gain (*Kqv*). *Iqh1* and *Iql1* specify maximum and minimum limits of reactive current injection, respectively. To disable the reactive power-voltage control function of the model, set *Kqv* to 0.

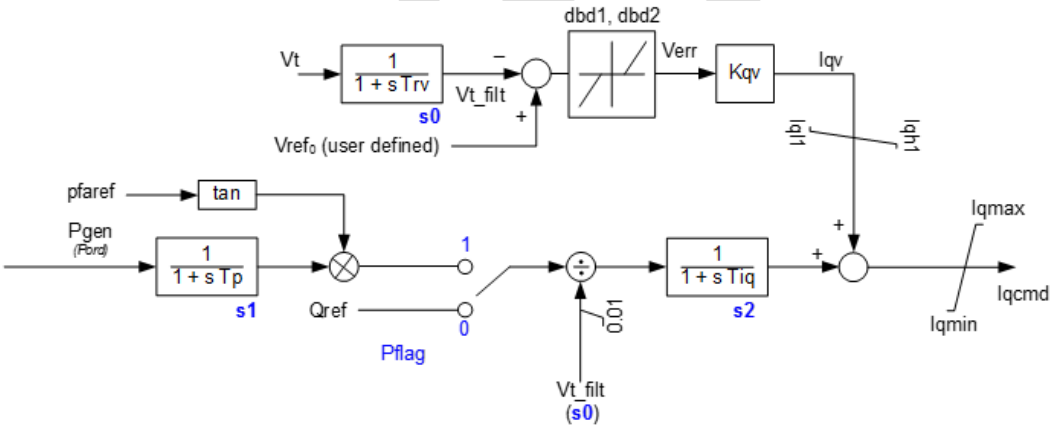


Figure 1.3: Reactive Power-Voltage Controls

Active-Reactive Current Priority Logic

With the active and reactive command values established in the active power-frequency and reactive power-voltage control elements, the command values are passed through maximum (*Ipmax*/*Iqmax*) and minimum (*Ipmin*/*Iqmin*) active and reactive current limits. Figure 1.4 shows the current limit logic and how that logic interacts with the limiters. When the *typeflag* parameter is set to 0, this denotes a DER that is a generating unit with *Ipmin* = 0, while setting it to 1 denotes a DER that is an energy storage device with *Ipmin* = -*Ipmax*.

Current limits, particularly in inverter-based resources, determine how the resource response to large grid disturbances such as faults on the BPS. The current limit logic is determined based on whether the resource is operated in active or reactive current priority, dictated by the *pqflag* parameter. The priority logic controls *Iqmax* and *Iqmin* based on the priority setting and maximum total current of the inverter (*Imax*). Figure 1.4 also shows the equations used for this control. For example, if reactive current priority is selected, then Iqmax and Iqmin are limited

to *Imax* and *-Imax*, respectively. Based on the reactive current ordered from the controls, the active current limit is then simultaneously calculated to utilize the remaining amount of total apparent current capability (*Imax*). A circular capability curve is assumed.

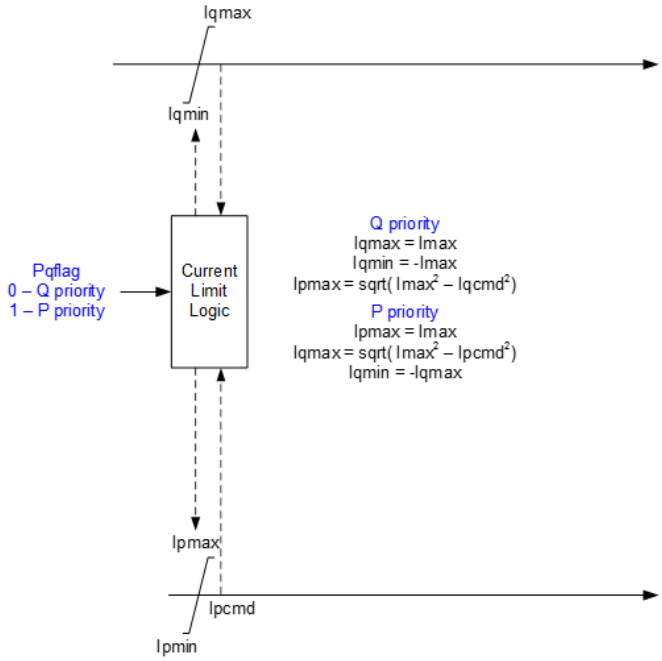


Figure 1.4: Active-Reactive Current Priority Controls

Example Consideration of Q Priority and P Priority

As an example, if the magnitude of current is limited to 1.2 pu (*Imax*) and the priority scheme is defined by reactive current priority, then a maximum limit of 1.2 pu is imposed on the reactive portion of current. The maximum active current (at this reactive current limit) will be $0.0pu = \sqrt{1.2^2 - 1.2^2}$. However, this does not imply that the active current will always be zero. This is the limited value of active current only when the reactive current is at its limit. However, if a reactive current of 1.0pu is sufficient for the system (as decided by the reactive power–voltage controls), then the maximum active current can be $0.66pu = \sqrt{1.2^2 - 1.0^2}$. Hence, here, the reactive power–voltage controller not only decides the amount of reactive current to be injected, but it also decides the maximum amount of active current that can be injected for the decided value of reactive current. The active current controller then decides the actual value of active current to be injected. A vice versa situation occurs when an inverter is in active current priority.

Prior to approval of IEEE Std. 1547-2018, all DERs on the system were not required to have reactive power–voltage control capability. Thus, the vintage of inverters that conform to this standard should have a P priority setting. With the approval of IEEE Std. 1547-2018, which requires inverters to have reactive power–voltage control capability (with preference to reactive current), it is expected that this capability will be used by the inverter, and thus, the current priority setting should be set to Q priority.

For example, upon the occurrence of a fault, a larger percentage of gross load can trip if located electrically close to the fault and if adjacent DERs are in Q priority, compared to when adjacent DERs are in P priority. However, at locations located electrically farther away from the fault, a larger percentage of gross load can trip when adjacent DERs are in P priority compared to when adjacent DERs are in Q priority. Closer to the fault, when in Q priority and with voltage control enabled, the DER reactive current would hit Imax and active current reduces to zero. The intention behind this is to try and support local voltage and prevent tripping of gross load. However, when the DER

active current contribution reduces to zero due to full output of reactive current (bear in mind that this is not to be confused with momentary cessation), the net load at the load substation bus increases which can result in voltage reducing at nearby non-DER causing load to trip. Now when the DER is in P priority, the net load at the load bus would be lower (assuming that the DERs have not gone into momentary cessation mode), and thus the voltage wouldn't fall as much at nearby non-DER buses, and as a result, a trip of gross load is lesser. Farther away from the fault, due to the initial higher voltage levels (as compared to the voltage levels closer to the faults), voltage support in Q priority has a greater effect and so even though the net load may increase (due to decrease in active current contribution from DER to accommodate injection of reactive current), the voltage drop due to increase in net load does not counterbalance the voltage support from the DER. And so, gross load does not trip as much.[19]

Fractional Tripping

The DER_A model includes a fractional tripping control that is intended to represent a portion of the DER tripping on low or high voltage,[20] as shown in Figure 1.5. The Vtripflag controls voltage tripping and the *Ftripflag* controls frequency tripping separately.[21] *Vrfrac* defines the fraction of DER that recovers after voltage returns to within acceptable limits after dropping below or above the threshold values. For frequency tripping, a single low (*fl*) and high (*fh*) frequency cut out break-point is implemented since frequency variation along the distribution feeder is relatively constant (as compared with voltage). Hence, there is no partial tripping due to frequency.[22] *Tv* is a time constant representing the time delay for voltage-related partial tripping (shown in Figure 1.5).

The *vl0* and *vl1* parameters are the low voltage cut out break-points and the *vh0* and *vh1* parameters are the high voltage cut out break-points. For example, when voltage falls below *vl1*, a fraction of the DER will cut out, with a linearly increasing amount of DER cutting out down to *vl0* where all DER will have cut out. The output of the fractional tripping block is the value that gets applied to *ipcmd* and *iqcmd*.[23] If voltage falls outside the specified thresholds for the pre-defined amount of time (below *tvl0* or *tvl1* or above *tvh0* or *tvh1*), then the recovery of resources changes from the black line to the red line. This is intended to represent only a fraction of resources recovering from the decrease in voltage (*Vrfrac*); rather, those resources trip off-line and return to service some time beyond a typical transient simulation.

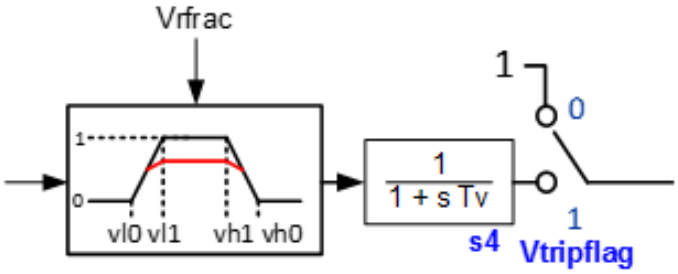


Figure 1.5: Fractional Tripping Controls

The fractional tripping logic does not represent any actual controls, but is rather an attempt at emulating the fact that on a feeder not all R-DER will necessarily experience the same terminal voltage and therefore may not trip at the same time and for the same level of voltage excursion at the head of the feeder. Thus, this is an attempt based on

[19] R. Quint, I. Green, D. Ramasubramanian, P. Pourbeik, J. Boemer, A. Gaikwad, D. Kosterev, C. DuPlessis, M. Osman, "Recommended DER Modeling Practices in North America," *25th International Conference and Exhibition on Electricity Distribution (CIRED) [under review]*.
[20] There is no partial tripping due to frequency in the *DER_A* model. If there is a frequency trip, then the entire amount of DER trips.
[21] GE PSLF does not have these flags; however, Siemens PTI PSS®E, PowerWorld Simulator, and Powertech TSAT do have these flags.
[22] If there is a frequency trip, then the entire amount of DER trips.
[23] Refer to the DER_A Model Specification document for a detailed pseudo code explanation of how the fraction/partical tripping is calcaulted. Available: https://www.wecc.biz/Reliability/DER_A_Final.pdf.

much deliberation among many participants and stakeholders to come up with a method to emulate such behavior. As experience is gained with the model, this and perhaps other aspects may be refined over time.

Refer to the model specification document for more details related to model implementation and pseudo code.[24]

Fractional Tripping Derivation

Key Takeaway:
The *DER_A* model does not include multiple points; however, these are likely not needed for stability studies in most cases. Typically, it is recommended to model the trip thresholds that relate to the shorter trip times since this scenario is what covers most stability simulations.

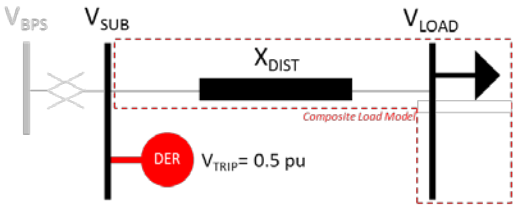
Specific data related to DER tripping is often not available, and engineering judgment must be used to determine reasonable tripping values. These values should be based on the expected vintage of DER and the distribution circuit characteristic. Each interconnection standard (e.g., IEEE Std. 1547-2003, IEEE Std. 1547a-2014, IEEE Std. 1547-2018) may have different ride-through and trip settings for abnormal voltage and frequency, with multiple magnitude–time duration pairs. Refer to Table 2.1 and Table 3.1 for details on setting these parameter values. TPs should coordinate with their DPs to attempt to track the proportion of DERs that could be expected to fall within each category. The proportion of DERs within each category may be inferred by DPs by assessing the date of each DER installation. The *DER_A* model does not include multiple points; however, these are likely not needed for stability studies in most cases. Typically, it is recommended to model the trip thresholds that relate to the shorter trip times[25] since this scenario is what covers most stability simulations. The thresholds are selected to account for the varied response of aggregate DER tripping across a distribution system, taking into account the voltage drop (V_{DROP}) across the feeder.

Fractional trip settings are based on how the DER is represented in powerflow and dynamics. Consider Figure 1.6 which shows different representations of U-DER and R-DER.

- **Option 1 (Recommended for U-DER):** U-DER is represented in the powerflow base case as a generator, and has an associated *DER_A* model in dynamics. The modeled U-DER is intended to represent one or multiple U-DER connected directly to or very close to the distribution substation. In this case, partial tripping is not applied, and the DER trip settings can mirror those specified in the respective interconnection requirements.
- **Option 2 (Recommended for R-DER):** An aggregate amount of R-DER spread throughout the distribution system is represented in the powerflow base case as a DER component of the load record. In dynamics, this information is integrated into the CLM with DER representation (e.g., *cmpldwg*). The equivalent distribution impedance is then represented in the CLM as well, with both load and DER represented at the load bus across the equivalent feeder impedance. Voltage drop across the feeder is accounted for explicitly. The Electric Power Research Institute (EPRI) research has shown that a voltage drop of 2-8% is typical for most distribution feeders; a value around 5% is a reasonable assumption for DER (and load) modeling. Assuming a trip setting of 0.5 pu is to be modeled (see Figure 1.6), then DER start tripping when the load bus voltage reaches 0.5 pu. All DER have tripped when the substation bus voltage reaches 0.5 pu, meaning that the load bus voltage is at 0.45 pu. Therefore, in this example, vl1 = 0.5 pu and vl0 = 0.45 pu. This concept can be used to determine trip settings for other standards as well.
- **Option 3:** An aggregate amount of R-DER spread throughout the distribution system can also be represented in the powerflow base case as a stand-alone generator. This does not necessarily follow the recommended framework described above; however, it is a modeling option. In this case, the same concept as presented in Option 2 applies, with some minor modifications. In this case, the DER is connected to the substation bus. DER start tripping when the implied load-side bus reaches 0.5 pu (so $V_{SUB} = V_{LOAD} + V_{DROP} = 0.55$ pu), and all

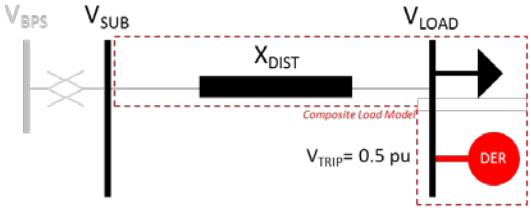
[24] P. Pourbeik, "Proposal for DER_A Model," September 11, 2018. [Online]. Available: https://www.wecc.biz/Reliability/DER_A_Final.pdf.
[25] As in, if the specification includes multiple trip magnitude-duration points, use the shortest duration point.

are tripped when the substation bus voltage reaches 0.5 pu. Therefore, in this example, vl1 = 0.55 pu and vl0 = 0.5 pu. Again, this concept can be applied to determine trip settings for other standards as well.



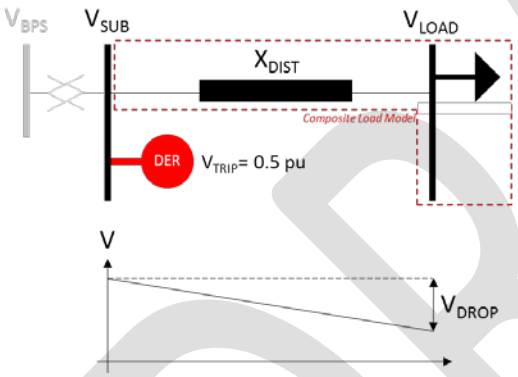
U-DER Represented by Generator Record (Option 1):

- Load modeling unrelated, since U-DER record explicitly represents a single (or group of) U-DER
- In this case, the resource likely has specific trip settings which can be gathered or estimated.
- No partial tripping implemented
  - Parameters vl0, vl1, vh0, and vh1 have direct relation to interconnection standard or requirements
  - Vfrac set to 0 or 1, depending on vintage



R-DER Represented as Part of Composite Load Model (Option 2):

- DER model represents aggregate DER spread across feeder
- Impedance represented in composite load model
  - V_{DROP} explicit across X_{DIST} ($V_{SUB} - V_{LOAD}$)
- DER start tripping when $V_{DER} = V_{LOAD} = 0.5$ pu
- DER will all have tripped when $V_{SUB} = 0.5$ pu
  - When $V_{LOAD} = V_{DER} = V_{SUB} - V_{DROP} = 0.5 - 0.05$ pu $= 0.45$ pu
- vl1 (start tripping) = 0.5 pu, vl0 (all tripped) = 0.45 pu



R-DER Represented by Generator Record (Option 3):

- DER model represents aggregate DER spread across feeder
- No distribution feeder impedance represented for DER
- DER start tripping when $V_{LOAD} = 0.5$ pu
  - When $V_{SUB} = V_{DER} = V_{LOAD} + V_{DROP} = 0.55$ pu
- DER will all have tripped when $V_{SUB} = V_{DER} = 0.5$ pu
- vl1 (start tripping) = 0.55 pu, vl0 (all tripped) = 0.5 pu

Figure 1.6: Fractional Trip Derivation Examples

The fractional trip settings can, in a very crude manner, be used to model momentary cessation if needed. For example, setting *vl1* and *vl0* to the momentary cessation settings will result in cessation of current below the specified thresholds. Selecting times *tvl0* and *tvl1* should be done with care to ensure the resources return following voltage recovery. Note that momentary cessation is not required for Category II resources in IEEE Std. 1547-2018, and is therefore not expected to be widely used in the North American interconnections.

Voltage Source Representation

In the *DER_A* model, a voltage source representation[26] is implemented at the network interface, to support numerical stability of the model in the simulation tools (see Figure 1.7).[27] In reality, all modern inverters used on the grid-side of power electronic interfaced energy sources use a voltage source converter (VSC). That is, a dc voltage source behind a full four-quadrant controlled dc to ac power electronic converter. The current through the VSC is strictly

[26] D. Ramasubramanian, Z. Yu, R. Ayyanar, V. Vittal and J. M. Undrill, "Converter Model for Representing Converter Interfaced Generation in Large Scale Grid Simulations", IEEE Trans. PWRS, April 2016.

[27] The *PVD1* and 2nd generation renewable energy system models use a current source representation, which has proved to cause numerical issues in simulations, particularly at increased penetration levels of these models.

controlled by the controls of the inverter. This can thus be represented as a voltage source behind an impedance. In order to develop the value of the voltage behind the impedance, the values of *ipcmd* and *iqcmd* are used to evaluate the voltage drop across the impedance and thereby develop the complex voltage. The representation is a voltage behind an reactance, *Xe*. Typical values for *Xe* are in the range of 0.25 pu.[28]

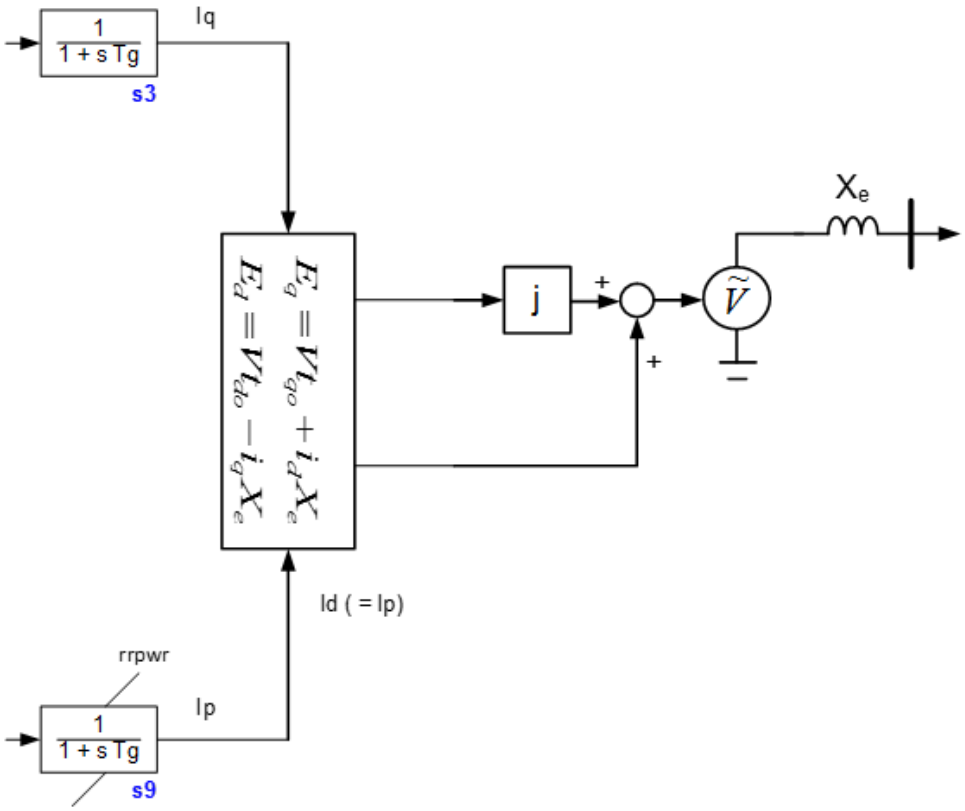


Figure 1.7: Voltage Source Representation

[28] Resistance is neglected, and the reactance value, *Xe*, is also a default value for numerical stability. A value of Xe of around 0.25 pu seems reasonable for this model.

Chapter 2: Parameterization of the DER_A Model

A challenge with any DER model, representing an aggregate response of many individual resources spread across a distribution system or feeder, is developing reasonable set of parameters to represent these resources. Table 2.1 provides a list of parameter values to represent different vintages of interconnection standards. These include IEEE Std. 1547-2003, IEEE Std. 1547a-2014, IEEE Std. 1547-2018 Category II[29] defaults, and CA Rule 21 defaults. Refer to the *DER_A* specification document or the software model libraries for a description of the model parameters.

Table 2.1: Default DER_A Model Parameters

Param[30]	IEEE Std. 1547-2003 Default	IEEE Std. 1547a-2014 Default	CA Rule 21 Default	IEEE Std 1547-2018 Category II Default	Notes
trv	0.02	0.02	0.02	0.02	† Note 1
dbd1	-99	-99	-99	-99	† Note 1
dbd2	99	99	99	99	† Note 1
kqv	0	0	0	0	† Note 1
vref0	0	0	0	0	† Note 2
tp	0.02	0.02	0.02	0.02	†
tiq	0.02	0.02	0.02	0.02	†
ddn	0	0	20	20	Note 3
dup	0	0	20	20	Note 3
fdbd1	-99	-99	-0.0006	-0.0006	Note 3
fdbd2	99	99	0.0006	0.0006	Note 3
femax	0	0	99	99	Note 3
femin	0	0	-99	-99	Note 3
pmax	1	1	1	1	† Note 4
pmin	0	0	0	0	Note 4
dpmax	99	99	99	99	†
dpmin	-99	-99	-99	-99	†
tpord	0.02	0.02	5	5	Note 3
imax	1.2	1.2	1.2	1.2	† Note 4
vl0	0.44	0.44	0.49	0.44	Note 5
vl1	$0.44+V_{DROP}$	$0.44+V_{DROP}$	$0.49+V_{DROP}$	$0.44+V_{DROP}$	Note 5
vh0	1.2	1.2	1.2	1.2	Note 5
vh1	$1.2–V_{DROP}$	$1.2–V_{DROP}$	$1.2–V_{DROP}$	$1.2–V_{DROP}$	Note 5
tvl0	0.16	0.16	1.5	0.16	Note 5
tvl1	0.16	0.16	1.5	0.16	Note 5
tvh0	0.16	0.16	0.16	0.16	Note 5
tvh1	0.16	0.16	0.16	0.16	Note 5
vrfrac	0	0	1	1	Note 5

[29] In IEEE Std. 1547-2018, the abnormal operating performance Category II "covers all BPS stability/reliability needs and is coordinated with existing reliability standards to avoid tripping for a wider range of disturbances of concern to BPS stability."

[30] Refer to the DER_A model specification for parameter names. Available: https://www.wecc.biz/Reliability/DER_A_Final.pdf.

Table 2.1: Default DER_A Model Parameters					
Param[30]	IEEE Std. 1547-2003 Default	IEEE Std. 1547a-2014 Default	CA Rule 21 Default	IEEE Std 1547-2018 Category II Default	Notes
fltrp	59.3	59.5 OR 57.0	58.5 OR 56.5	58.5 OR 56.5	Note 6
fhtrp	60.5	60.5 OR 62.0	61.2 OR 62.0	61.2 OR 62.0	Note 6
tfl	0.16	2.0 OR 0.16	300.0 OR 0.16	300.0 OR 0.16	Note 6
tfh	0.16	2.0 OR 0.16	300.0 OR 0.16	300.0 OR 0.16	Note 6
tg	0.02	0.02	0.02	0.02	†
rrpwr	0.1	0.1	2.0	2.0	Note 8
tv	0.02	0.02	0.02	0.02	†
kpg	0	0	0.1	0.1	Note 3
kig	0	0	10	10	Note 3
xe	0.25	0.25	0.25	0.25	† Note 8
vpr	0.8	0.8	0.3	0.3	Note 6
iqh1	0	0	1	1	Note 1
iql1	0	0	-1	-1	Note 1
pflag	1	1	1	1	† Note 7
frqflag	0	0	1	1	Note 7
pqflag	P priority	P priority	Q priority	Q priority	Note 7
typeflag	1	1	0 OR 1	0 OR 1	Note 7

Parameterization Notes

The following notes describe considerations and background on the parameter values selected above. Refer to each respective interconnection standard for more information.

NOTE †: Default Parameters Not Typically Subject to Change

These parameters do not typically change across different implementations of the *DER_A* model. Any modification from the recommended default values should be carefully analyzed and justified.

NOTE 1: Voltage Control Parameters

In most existing applications, DER does not control voltage. In such cases, the voltage control function should be disabled by setting the voltage control gain, *Kqv*, to 0. The lower and upper voltage deadbands, *dbd1* and *dbd2*, should be set large values (e.g., -99 and 99), respectively. However, interconnection standards state that the voltage control "capability" must be provided in the DER. If the capability is being utilized or required by the local utility, then this setting should be modified accordingly.

When DER is controlling voltage, the dynamic model needs to be adapted to account for this. As the model is not able to simultaneously represent both steady-state voltage control (Clause 5.3.3. voltage-reactive power mode in IEEE Std. 1547-2018) and dynamic voltage control (Clause 6.4.2. dynamic voltage support in IEEE Std. 1547-2018), a modeling compromise must be made. Therefore, it is recommended that the dynamic voltage support settings be implemented since most simulations involve fault-type conditions with large voltage fluctuations. Reasonable default values are *trv* = 0.02, *kqv* = 5[31], *dbd1* = –0.12, *dbd2* = 0.1, *iqh1* = 1, and *iql1* = –1.[32] Any situation where *Kqv* is non-

[31] Allows for maximum reactive current injection when voltage falls below around 0.7 pu, taking into consideration the voltage deadband.

[32] Again, note that the values in Table 2.1 do not use these settings because the respective interconnection agreements do not require dynamic voltage control to be used. Hence, *kqv* is set to 0.

zero (dynamic voltage control is enabled), care should be taken to ensure that the corresponding deadband is not too small, which would lead to voltages possibly jumping across deadband thresholds each simulation iteration.

NOTE 2: Voltage Reference

The recommended setting for *Vref0* is 0. Setting *Vref0* equal to 0 allows the model to set its own terminal voltage reference based on the initial conditions. This is consistent with the language in IEEE Std. 1547-2018, in 5.3.3 (voltage-reactive power mode), that requires that DER shall be capable of autonomously adjusting reference voltage (*Vref*), with *Vref* being equal to the (low pass filtered) measured voltage.

NOTE 3: Active Power-Frequency Control

In IEEE Std. 1547-2003 and IEEE Std. 1547a-2014, active power-frequency control is not specified. Therefore, the gains *Ddn* and *Dup* as well as the frequency errors femax and femin are set to 0. This disables the active power-frequency controls in the model for these two standards. In CA Rule 21 and IEEE Std. 1547-2018, the capability for resources to have active power-frequency controls installed and enabled (as default) are specified. Therefore, per the standard *Dup* should be set to 20 (representing a 5% droop characteristic).[33] Newer installations of DER with frequency response capability can also respond to overfrequency conditions, and therefore *Ddn* is set to 20. Deadband for both standards is set to ±0.0006 pu, or ±36 mHz. *Tpord* is used to represent the specified open loop time constant of 5 seconds per IEEE Std. 1547-2018 and CA Rule 21, and is set to a small value (0.02 sec) when these controls are disabled in previous IEEE Std. 1547 versions. Parameters *Kpg* and *Kpi* are not directly mappable to the interconnection standards; values describe in Table 2.1 were used in benchmark testing of the *DER_A* model are based on engineering judgment and were found to provide satisfactory response.

NOTE 4: Active Power Capability

Maximum active power output is set to a default of 1 pu. Minimum active power output is assumed to be 0 pu for generating resources, but can be negative (i.e., -1 pu) for energy storage resources. These maximum and minimum active power capability values can be modified if more detailed information is known about specific DER. Inverter-based DER have an overload capability of around 110-120% and therefore *imax* is set to 1.2 pu. Other types of DER may have a different current limit, and this can be adjusted carefully if additional information is known. However, for most inverter-based installations (e.g., solar PV), a value of 1.2 pu is a reasonable approximation.

NOTE 5: Partial Tripping

Vrfac, the ratio of DER that restore output upon voltage recovery, should be set to 0 for legacy[34] DER (i.e., no DER restore output following a ride-through event), 1.0 for modern DER (i.e., all DER restore output following a ride-through event), and some value in between for a mix of legacy and modern DER based on the assumed vintage of DER deployed. A value of *vrfrac* = 0 is a conservative assumption, and should be used if no detailed DER information is available. Since CA Rule 21 and IEEE Std. 1547-2018 are relatively new standards, it can be expected that, for now, *Vrfrac* can be set at or near 0.

The interconnection standards include different levels of trip settings, typically a longer duration trip time with magnitude closer to nominal and a shorter duration trip time with lower (or higher) magnitude away from nominal. Table 2.1 includes values for the shorter duration trip thresholds since these values are likely the most useful and relevant settings for stability studies. Consult the relevant interconnection standards and requirements for more information on longer duration trip settings.

V_{DROP} should be set to a reasonable equivalent voltage drop across the distribution system, in the range of 2-8% (reasonable default of 5%), if no detailed information is available. Voltage trip thresholds include a 0.01 pu offset from the interconnection standard values to correctly account for the beginning and completion of partial tripping.

[33] See Chapter 3 on recommended settings. Since most DER will be operated at maximum available power, and will not have available generating capability to respond in the upward direction for underfrequency events, Dup should be set to 0, from a practical standpoint.

[34] Use of the term "legacy" generally refers to DER compliant with IEEE Std. 1547-2003 and IEEE Std. 1547a-2014, which typically involve limited or no controls and ride-through capability.

The values specified in the table represent R-DER represented as part of the CLM. If individual (or multiple similar) U-DER are represented, trip settings should be equal and set to the corresponding value in the interconnection standard. If aggregate R-DER are to be represented by a generator record, use the methodology described in Chapter 1 to determine correct trip settings.

In cases where momentary cessation of inverter-based resources needs to be represented, this can be accomplished using *vl1* and *vl0* with extended trip times. Note that this may hinder the ability to capture any tripping effects due to existing model limitations. Engineering judgment and sensitivity studies should be used when applying these types of settings.

NOTE 6: Frequency Trip Levels

High (fhtrp) and low (fltrp) frequency tripping has different thresholds in a few of the interconnection standards, as described in Table 2.1. Again, each has a specified time threshold. The frequency thresholds closer to nominal frequency have a longer duration while the thresholds further from nominal have a shorter duration.

In simulations where frequency does not fall below under-frequency load shedding (UFLS) levels, the setting values for CA Rule 21 and IEEE Std. 1547-2018 are not significant.[35] However, the settings representing IEEE Std. 1547-2003 and IEEE Std. 1547a-2014 are relevant, particularly for the thresholds closer to nominal frequency. IEEE Std. 1547-2003 has only one magnitude and time value. IEEE Std. 1547a-2014 has two thresholds, but most commonly only the 59.5 Hz and 60.5 Hz thresholds, with 2 second timers, are applicable.

Disabling tripping on frequency during low voltage is implemented in almost all relay models as the relay needs a sufficient voltage waveform to measure frequency. Under fault conditions, due to the large change in voltage, the frequency calculation can result in a spurious spike, and thus frequency tripping should be disabled. IEEE Standard C37.117[36] recommends disabling the frequency trip when the voltage is below 50-70% of nominal. For DERs, this voltage levels was increased to 80% to account for further inaccuries in frequency calculation that may arise in positive sequence simulations.[37]The first sentence of IEEE Std. 1547-2018, Clause 6.5.1, states that when frequency meets a certain criteria and "the fundamental-frequency component of voltage on any phase is greater than 30% of nominal", then the DER can respond. However, if the frequency is outside acceptable range but voltage is less than the 30% threshold, then DER should not trip. This represents a low voltage inhibit function in the frequency tripping, and is represented by parameter *Vpr*.[38] Regardless, study engineers should monitor for false trips by the DER_A model that may not be realistic; rather, they are an artifact of positive sequence stability simulation calculation of frequency. Close review of any frequency-related tripping is strongly recommended.

NOTE 7: Control Flags

The parameter *pflag* sets power factor control. If set to 1, then the power factor angle reference is used based on initialization of the model. Otherwise, if set to 0, then the reactive power reference (*Qref*) will be used.

The parameter *frqflg* sets the active power-frequency control capability. If set to 0, then active power reference (*Pref*) is used. Otherwise, if set to 1, then the active power-frequency control loop is enabled. If *frqflg* is set to 1, the resource will response to over- and under-frequency disturbances. However, if the user sets Dup to 0, the resource will not respond to underfrequency. This configuration emulates the unit(s) operating at maximum available power output.

The parameter *pqflag* specifies whether to use active or reactive current priority, which is effective when the current limit logic is in effect. This is particularly used during response to large disturbances (i.e., faults).

[35] Unless specific studies are being performed to configure UFLS systems.
[36] IEEE C37.117-2007, IEEE Guide for the Application of Protective Relays Used for Abnormal Frequency Load Shedding and Restoration.
[37] https://www.wecc.biz/Reliability/WECC_White_Paper_Frequency_062618_Clean_Final.pdf.
[38] *Vpr* may also be referred to as *Vfth*.

The parameter *typeflag* specifies whether the resource is a generating resource (set to 0) or an energy storage device (set to 1). Setting as an energy storage device allows absorbtion of active power, and emulates distributed energy storage. This does not, however, emulate charging and discharging of the resource.

NOTE 8: Voltage Source Representation

The *rrpwr* specifies the active current ramp rate. IEEE Stds. 1547-2003 and 1547a-2014 did not specify an active current ramp rate; however, IEEE Std. 1547-2018 and CA Rule 21 use a 80% recovery within 0.4 seconds, which can be approximated with a gain of 2 pu/sec, which equates to full recovery within 0.5 seconds. The voltage source impedance also uses a default values for *Xe* of 0.25, based on robustness testing of the *DER_A* model during its development.

Future Model Implementation Improvement

Commercial simulation software vendors should consider adding a new global flag for inverter-based resources (particularly renewable energy resources) that sets the maximum available power to the current power output (Pgen) upon initialization of the inverter-based models. This can then be changed by the user on a case-by-case basis during the simulation, if necessary (e.g., to represent curtailing). For example, simulations with renewable generation dispatched at less than maximum capacity (Pmax) may represent less solar irradiance or lower wind speed. However, this is the maximum available power output for the assumed conditions. As more resources are being installed with the capability to provide active power-frequency control, the ability to distinguish whether units are operating at maximum available power output will be increasingly important. This parameter is similar to the baseload flag for synchronous generating resources.

DRAFT

Chapter 3: Practical DER_A Model Implementation

Table 2.1 in the previous chapter provides parameter values that relate to specific interconnection standards and requirements; however, many systems are faced with an aggregate DER that encompasses many vintages of interconnection requirements and settings. Table 3.1 provides a set of default parameter values for different systems based on the penetration of different IEEE Std. 1547 vintages, ranging from a system dominated by IEEE Std. 1547-2003 interconnections to a system of modern IEEE Std. 1547-2018 interconnections. Also shown are default values for pentrations at 70% -2003 vintage and 30% -2018 vintage, as well as 30% -2003 vintage and 70% -2018 vintage. These default values are based on engineering judgment, and are intended to be used as a starting point for more detailed studies and sensitivities.[39] Parameter values that are subject to changes across interconnection vintages are highlighted in red in Table 3.1 and described in this chapter. Note that some of the parameter values subject to change are a linear interpolation based on the penetration of specific vintages of DER.

Table 3.1: Default Parameter Selection for Mixed Vintages of DER

Param	Early Vintage DER System IEEE Std. 1547-2003	70% of -2003 30% of -2018	30% of -2003 70% of -2018	Newer Vintage DER System IEEE Std. 1547-2018
trv	0.02	0.02	0.02	0.02
dbd1	-99	-99	-99	-99
dbd2	99	99	99	99
kqv	0	0	0	0
vref0	0	0	0	0
tp	0.02	0.02	0.02	0.02
tiq	0.02	0.02	0.02	0.02
ddn	0	6	14	20
dup	0	0	0	0
fdbd1	-99	-0.0006	-0.0006	-0.0006
fdbd2	99	0.0006	0.0006	0.0006
femax	0	0	99	99
femin	0	0	-99	-99
pmax	1	1	1	1
pmin	0	0	0	0
dpmax	99	99	99	99
dpmin	-99	-99	-99	-99
tpord	0.02	0.02	5	5
imax	1.2	1.2	1.2	1.2
vl0	0.44	0.44	0.44	0.44
vl1	0.49	0.49	0.49	0.49
vh0	1.2	1.2	1.2	1.2
vh1	1.15	1.15	1.15	1.15
tvl0	0.16	0.16	0.16	0.16

[39] Transmission-distribution co-simulation techniques may be used to help further parameterize *DER_A* models based on specific distribution feeder configurations and DER penetration levels.

Table 3.1: Default Parameter Selection for Mixed Vintages of DER				
Param	**Early Vintage DER System IEEE Std. 1547-2003**	**70% of -2003 30% of -2018**	**30% of -2003 70% of -2018**	**Newer Vintage DER System IEEE Std. 1547-2018**
tvl1	0.16	0.16	0.16	0.16
tvh0	0.16	0.16	0.16	0.16
tvh1	0.16	0.16	0.16	0.16
vrfrac	0	0.3	0.7	1.0
fltrp	59.3	58.5	57.5	56.5
fhtrp	60.5	61	61.5	62.0
tfl	0.16	0.16	0.16	0.16
tfh	0.16	0.16	0.16	0.16
tg	0.02	0.02	0.02	0.02
rrpwr	0.1	0.6	1.4	2.0
tv	0.02	0.02	0.02	0.02
kpg	0	0.1	0.1	0.1
kig	0	10.0	10.0	10.0
xe	0.25	0.25	0.25	0.25
vfth	0.8	0.3	0.3	0.3
iqh1	0	1.0	1.0	1.0
iql1	0	-1.0	-1.0	-1.0
pfflag	1	1	1	1
frqflag	0	1	1	1
pqflag	P priority	P priority	Q priority	Q priority
typeflag	0	0	0	0

The following considerations are made in the development of these default parameter values, and are intended to provide transparency and understanding of how these parameters were devised. However, they are intended as default values that may be subject to change if more detailed information is known.

- **Upward Frequency Responsiveness for Underfrequency Conditions:** In this set of default parameters, it is assumed that the vast majority (if not all) DER are operated at maximum available[40] power and thus cannot provide frequency response for underfrequency conditions.[41] To model the inability to provide response in the upward direction, the *Dup* parameter value is set to 0. This disables upward movement regardless of where the DER resource(s) is dispatched relative to *Pmax* in the dynamics data. This allows for easy manipulation of DER output levels without needing to modify additional parameter values for each sensitivity case. Another option is to set the *Dup* parameter value according to the expected performance, and then modifying *Pmax* value in the dynamics data to match the pre-disturbance output for each operating conditions studied. However, this requires an additional step and may lead to unexpected frequency responsiveness from DER if not adequately handled when changing DER dispatch levels.

[40] If studies are assuming that DER are curtailed for any reason, IEEE Std. 1547-2018 vintage DER will have the capability to respond to underfrequency events.

[41] This statement relates to DER that are generating resources; this may not be the case for energy storage. Energy storage not injecting maximum power will be able to respond to underfrequency events following a droop characteristic.

- **Downard Frequency Responsiveness for Overfrequency Conditions:** *Ddn* is modified across the different penetration levels to represent an effective droop characteristic, or a response from a fractional value of DER based on the penetration of modern inverters. The 5% droop (*Ddn* = 20) is multipled by a linear factor based on this penetration (e.g., 70% of 20 equals 14).
- **Frequency Deadband and Error Limits:** When frequency response is enabled in the model, the deadband settings of *fdb1* and *fdb2* as well as the frequency error settings of *femax* and *femin* need to be modified to enable accurate representation of these controls. A default value is used in all cases where control is enabled.
- **Voltage-Related Trip Settings and Times:** Refer to the Chapter 1 for the derivation of the partial trip values. Note that trip thresholds and times may vary if applying CA Rule 21. Values assume a voltage drop, V_{DROP}, of 5%.
- **Fraction of Resources Recovering:** The parameter *vrfrac* represents the fraction of resources that recover upon voltage recovery following abnormal voltage conditions. It is expected that resources meeting IEEE Std. 1547-2018 will recover from abnormal voltages and ride through disturbances while IEEE Std. 1547-2003 resources will likely trip and remain disconnected for the duration of stability simulations. A linear multipler is used based on the fraction of resources connected to the system. For example, for a 70% IEEE Std. 1547-2018 system, *vrfrac* = 0.7.
- **Frequency-Related Trip Settings:** Frequency-related trip settings of fltrp and fhtrp are assumed to slightly vary based on the aggregate vintage of DER connected. For the shorter-term tripping, IEEE Std. 1547-2003 has trip settings at 59.3 Hz and 60.5 Hz while IEEE Std. 1547-2018 has trip settings at 57.5 Hz and 62 Hz. For mixed penetrations, a linear multiplier is used to vary the level of DER tripping. This is an approximate; yet these trip settings are below the first stage of UFLS, and are therefore not likely to make a substantive impact in most stability simulations.[42] More detailed studies should consider identifying more accurate information for these settings.
- **Active Current Recovery Ramp Rate:** The parameter *rrpwr* is modified across different penetration levels to represent the fraction of resources that recover from abnormal voltage conditions. 2.0 pu/sec (recovery in 0.5 seconds) is used for IEEE Std. 1547-2018 resources, and a linear multiplier is used for the mixed penetration conditions. For example 70% of 2.0 pu/sec equals 1.4 pu/sec.
- **Frequency Response PI Controls:** When frequency response controls are enabled in the model, default parameter values of *kpg* = 0.1 and *kig* = 10 are used.
- **Type Flag:** In these default data sets, the *typeflag* is set to 0 representing a generating resource. This flag, and relevant parameter values can also be modified to represent an energy storage resource.

[42] Stability studies for establishing UFLS set points, where simulated frequency can fall well below UFLS, should ensure reasonable frequency-related trip settings are used for DER.

Chapter 4: DER_A Model Benchmarking and Testing

To ensure that the model is usable for industry-wide studies, some form of model benchmarking and testing is typically performed by industry partners. DER_A model development and testing was led by the Western Electricity Coordinating Council (WECC) Renewable Energy Modeling Task Force (REMTF) and Load Modeling Task Force (LMTF), with EPRI providing the model benchmarking support.

EPRI performed extensive DER_A model benchmarking, working with the major commercial software vendors[43] following their implementation of the standalone DER_A model. A test system using a play-in voltage source model at the transmission bus with constant impedance load adjacent to the DER was used for the testing. A suite of 19 tests was used to apply small and large disturbances of voltage and frequency, and the model's active and reactinve power response and set points were observed. The response of the DER_A model was compared for each test across all platforms to determine whether the models match the same general trend in response (i.e., they are considered suitably benchmarked). Refer to an EPRI white paper on this topic (reference 11 in Appendix A).[44] Figure 4.1 shows an example benchmarking simulation, and demonstrates how the DER_A model in each of the software platforms matches the same general performance characteristic.

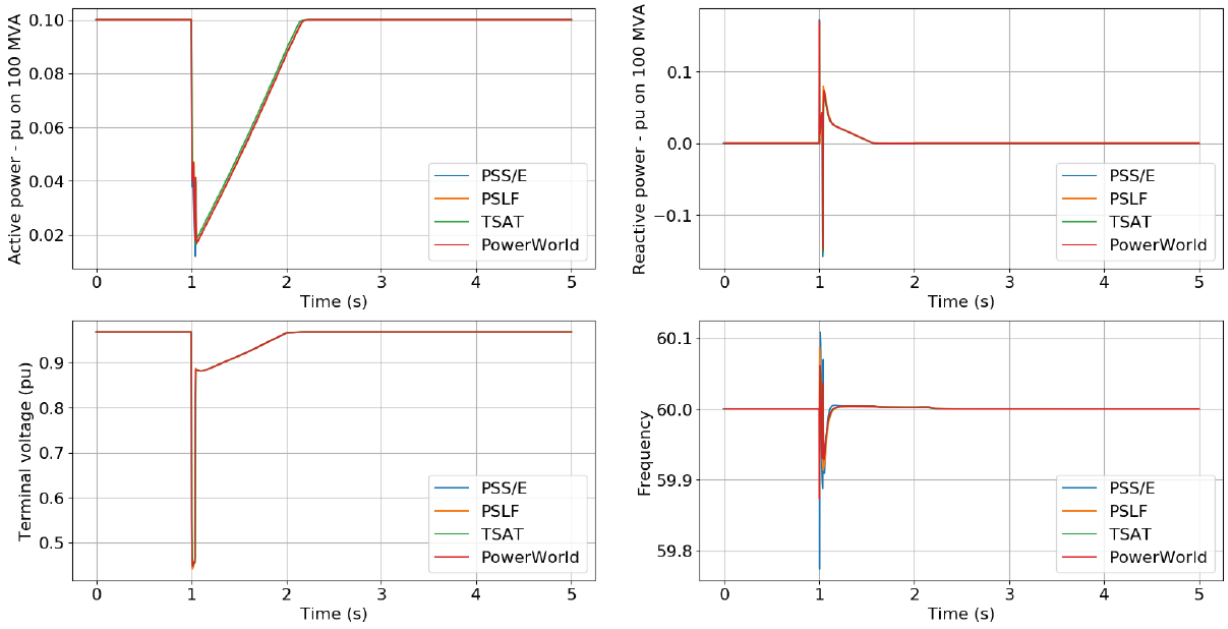


Figure 4.1: Voltage Sag Benchmarking Test Result [Source: EPRI]

To ensure that the model is numerically robust and usable in system studies on a large-scale case, CAISO has been testing the DER_A model on WECC-wide base cases for their reliability studies. Figure 4.2 shows one example of the types of sensitivity studies performed by CAISO. CAISO has been testing the model with different parameter values, including CA Rule 21 and the new IEEE Std. 1547-2018 default settings. The model has performed well and numerically robust in these studies using GE-PSLF™.[45]

[43] Including GE-PSLF™, Siemens PTI PSS®E, PowerWorld Simulator, and PowerTech Labs TSAT.
[44] Electric Power Research Institute (EPRI) (2016): Distributed Energy Resources Modeling for Transmission Planning Studies. Summary Modeling Guidelines. 3002009485. Palo Alto, CA. Available online at http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002009485.
[45] CAISO, "CMPLDWG Composite Model with Distributed Generation DER_A CAISO Assessment," NERC LMTF Meeting, May 2018. Available: https://www.nerc.com/comm/PC/LoadModelingTaskForceDL/CMPLDWG_DER_A_CAISO_NERC.pdf.

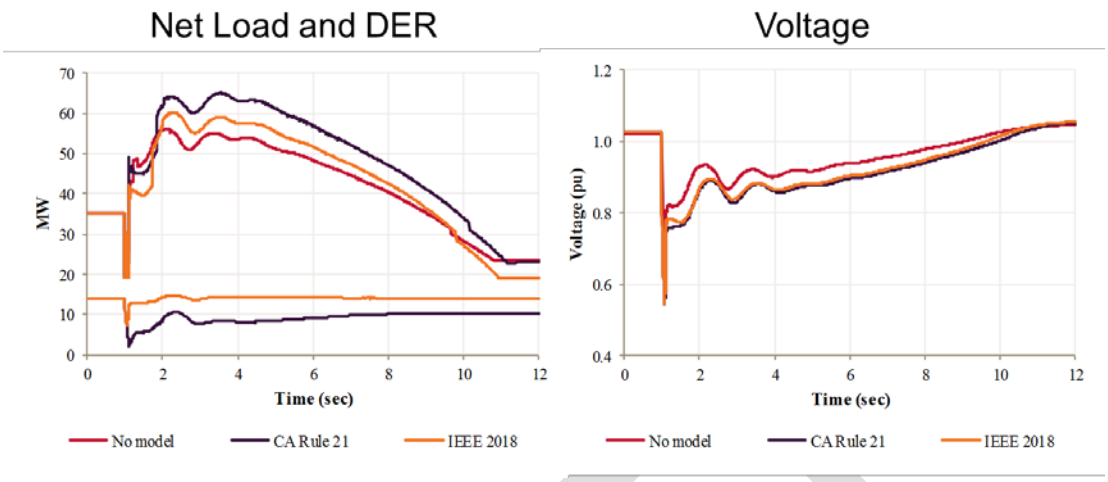


Figure 4.2: CAISO DER Study Example including DER_A Model [Source: CAISO]

EPRI has also performed system studies on the full Eastern Interconnection base case, in coordination with Duke Energy. These studies implemented the DER_A model on 138 U-DER installations with capacity of 1,300 MW. Figure 4.3 shows the DER response from an example simulation using these models. It shows that some of the DER_A models near the fault location respond to with active and reactive power response to the disturbance, and those further away from the disturbance do not provide a significant response. Again, the implemented DER_A models are numerically robust.[46]

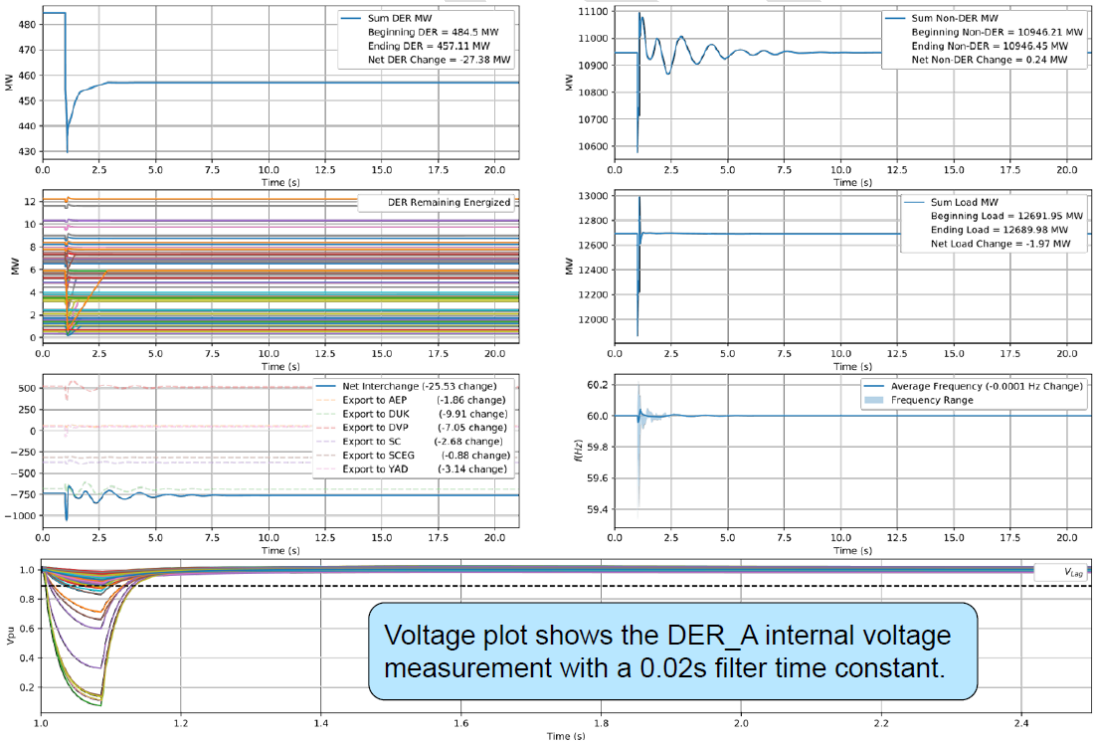


Figure 4.3: EPRI DER Study Example including DER_A Model [Source: CAISO]

[46] EPRI, "Preliminary results of DER_A model parameterization", NERC LMTF Meeting, July 2018. Available: https://www.nerc.com/comm/PC/LoadModelingTaskForceDL/Parameterization_of_DER_A_Model_v1_DR.pdf.

Appendix A: References

DER_A Model Specification Document

[1] P. Pourbeik, "Proposal for DER_A Model," September 11, 2018. [Online]. Available: https://www.wecc.biz/Reliability/DER_A_Final.pdf.

Relevant Interconnection Standards

[2] IEEE Std. 1547-2003, Standard for Interconnecting Distributed Resources with Electric Power Systems, July 2003. Available: https://standards.ieee.org/standard/1547-2003.html.

[3] IEEE Std. 1547a-2014, IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems – Amendment 1, May 2014. [Online]. Available: https://standards.ieee.org/standard/1547a-2014.html,

[4] IEEE Std. 1547-2018, IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces, April 2018. [Online]. Available: https://standards.ieee.org/findstds/standard/1547-2018.html.

[5] IEEE Std. 1547-2018, 6/4/2018: Errata to IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces. Available online at http://standards.ieee.org/findstds/errata/1547-2018_errata.pdf.

[6] CPUC: Interconnection (Rule 21). California Public Utilities Commission. Available online at http://www.cpuc.ca.gov/Rule21/.

Relevant NERC Standards, Guidelines, and Reports

[7] NERC, "Distributed Energy Resources: Connection Modeling and Reliability Considerations," Atlanta, GA, Feb 2017. [Online]. Available: https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy_Resources_Report.pdf.

[8] NERC, "Reliability Guideline: Modeling Distributed Energy Resources in Dynamic Load Models," Atlanta, GA, Dec 2016. [Online]. Available: https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_-_Modeling_DER_in_Dynamic_Load_Models_-_FINAL.pdf.

[9] NERC, "Reliability Guideline: Distributed Energy Resource Modeling," Atlanta, GA, Sept 2017. [Online]. Available: https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_-_DER_Modeling_Parameters_-_2017-08-18_-_FINAL.pdf.

DER_A Parameterization References

[10] EPRI, The New Aggregated Distributed Energy Resources (der_a) Model for Transmission Planning Studies, Product ID: 3002013498, May 8, 2018.

[11] Electric Power Research Institute (EPRI) (2016): Distributed Energy Resources Modeling for Transmission Planning Studies. Summary Modeling Guidelines. 3002009485. Palo Alto, CA. Available online at http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002009485.

[12] EPRI (2017): Distributed Energy Resources Modeling for Transmission Planning Studies. Detailed Modeling Guidelines. 3002010932. Electric Power Research Institute (EPRI). Palo Alto, CA. Available online at https://www.epri.com/#/pages/product/000000003002010932/ .

[13] I. Alvarez-Fernandez, D. Ramasubramanian, A. Gaikwad, J. Boemer, "Parameterization of Aggregated Distributed Energy Resources (DER_A) Model for Transmission Planning Studies," 2018 Grid of the Future Symposium, CIGRE US National Committee, Reston, VA, 2018.

[14] EPRI (2018) Selected Case Studies Analyzing the Impact of DER on the Bulk System Voltage Performance: Impact of Aggregate Distributed Energy Resources on a Large System, EPRI, Palo Alto, CA: 2018, 3002013502.

[15] EPRI (2018) Detailed Distribution Circuit Analysis and Parameterization of the Partial Voltage Trip Logic in WECC's DER Model (DER_A): Towards regional default settings in the absence of detailed distribution circuit data, EPRI, Palo Alto, CA: 2018, 3002013500.

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Other Reference Material

[16] D. Ramasubramanian, Z. Yu, R. Ayyanar, V. Vittal and J. M. Undrill, "Converter Model for Representing Converter Interfaced Generation in Large Scale Grid Simulations", IEEE Trans. PWRS, April 2016.

[17] WECC, "Wind Plant Dynamic Modeling Guidelines," Salt Lake City, UT, April 2014. [Online]. Available: https://www.wecc.biz/Reliability/WECC%20Wind%20Plant%20Dynamic%20Modeling%20Guidelines.pdf.

[18] WECC, "Solar Plant Dynamic Modeling Guidelines," Salt Lake City, UT, April 2014. [Online]. Available: https://www.wecc.biz/Reliability/WECC%20Solar%20Plant%20Dynamic%20Modeling%20Guidelines.pdf.

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Appendix B: DER_A Block Diagram

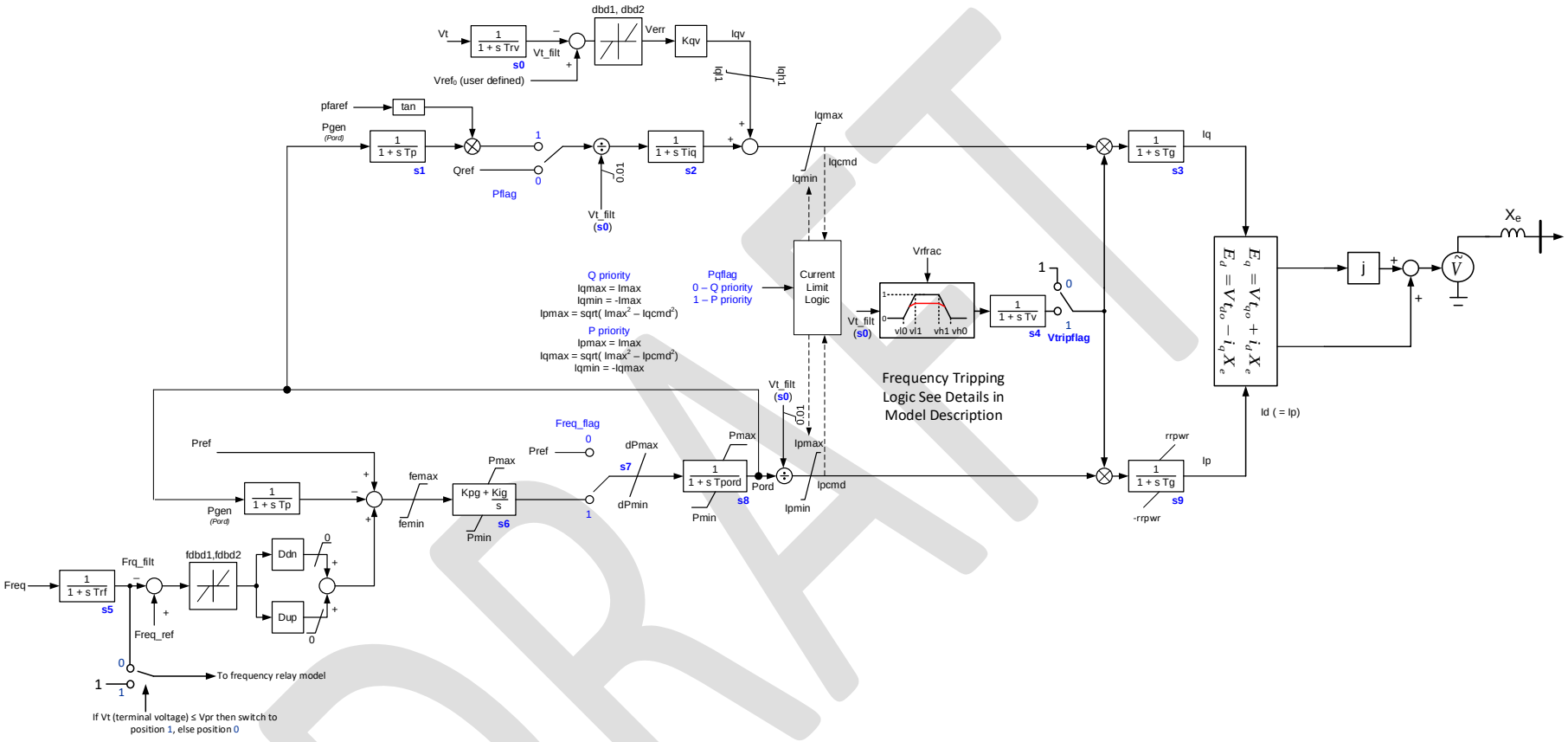

Figure B.1: *DER_A* Model Block Diagram

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Contributors

NERC gratefully acknowledges the invaluable contributions and assistance of the following industry experts in the preparation of this guideline. NERC would like to acknowledge the Electric Power Research Institute (EPRI) for the technical leadership in developing this guideline. NERC also would like to acknowledge all the contributions of the NERC System Planning Impacts of Distributed Energy Resources Working Group (SPIDERWG) and the NERC Load Modeling Task Force (LMTF).

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Northeast Power Coordinating Council, Inc. Regional Standards Committee

FERC Orders and NOPRs of Interest

Guy V. Zito
NPCC AVP - Standards

FERC – Orders and Notice of Proposed Rulemakings (NOPRs):

- Letter Order Approving the Joint Petition Requesting Certain Approvals in connection with the Dissolution of FRCC
- Notice of Proposed Rulemaking to Approve Reliability Standard CIP-012-1
- Letter Order Approving Amendments to Appendix 3A of the NERC ROP, Standards Processes Manual

FRCC Regional Entity Dissolved

- FERC issued a letter order on April 30, 2019 approving the Joint Petition filed by NERC, SERC and FRCC on February 27, 2019 requesting certain Commission approvals in connection with the Dissolution of FRCC as a Regional Entity.
- Changes to the SERC Regional Delegation Agreement between NERC and SERC to reflect the new, regional boundaries for SERC due to the transfers of FRCC registered entities.
- Transfer of Registered Entities of FRCC to SERC will be effective on July 1, 2019

FERC -NOPR to Approve CIP-012-1, Cyber Security Communications between Control Centers (cont.)

- Issued April 18, 2019
- The proposed Reliability Standard addresses the Commission's directive from Order No. 822 to modify the Critical Infrastructure Protection Reliability Standards to require Responsible Entities to implement controls to protect communication links and sensitive Bulk Electric System data communicated between BES Control Centers.

FERC -NOPR to Approve CIP-012-1, Cyber Security Communications between Control Centers (cont.)

- Applicable to RC, TOP, BA, TO, GO, and GOP
- Single Requirement with Subreqs. (paraphrased)
  - Mitigate the risks posed by unauthorized disclosure and unauthorized modification of RTA and monitoring data while being transmitted between any applicable Control Centers
    - Identification of security protection used
    - Identification of where the Responsible Entity applied the security protection
    - Identification of the responsibilities of each Responsible Entity for multiple ownership CCs

FERC -NOPR to Approve CIP-012-1, Cyber Security Communications between Control Centers (cont.)

- FERC proposes to approve the standard however seeks comment on two proposed Directives
  - the CIP Reliability Standards do not address the availability of communication links and data communicated between bulk electric system Control Centers (require protections); and
  - proposed Reliability Standard CIP-012-1 does not adequately identify the types of data covered by its Requirements, due to, among other things, the fact that the term “Real-time monitoring” is not defined.

FERC -NOPR to Approve CIP-012-1, "Cyber Security Communications between Control Centers"

FERC Notes the following:

- IRO-002-5 and TOP-001-4 require responsible entities to have redundant and diversely routed data exchange infrastructure within the Control Center environment, but do not pertain to communications between individual Control Centers (in Order 822)
- Comments due to FERC 60 days from published date in the Federal Register

Letter Order Approving Amendments to Appendix 3A of the NERC ROP, Standards Processes Manual

- Approved March 1, 2019, in effect, and posted
- Changes to Manual include;
  - enhance processes for field tests to support standards development and for posting supporting technical documents (Section 6);
  - improve processes for appeals and interpretations (Section 7);
  - provide language to clarify existing standard processes (Section 11 supporting technical documents); and
  - streamline language, correct capitalization or titles of documents, and make other necessary updates.

“Intelligence is the ability to adapt to change.”-
Stephen Hawking

Questions or Comments ?

Northeast Power Coordinating Council, Inc. Regional Standards Committee

Resilience Summit
April 3-4, 2019

Guy V. Zito
NPCC AVP - Standards

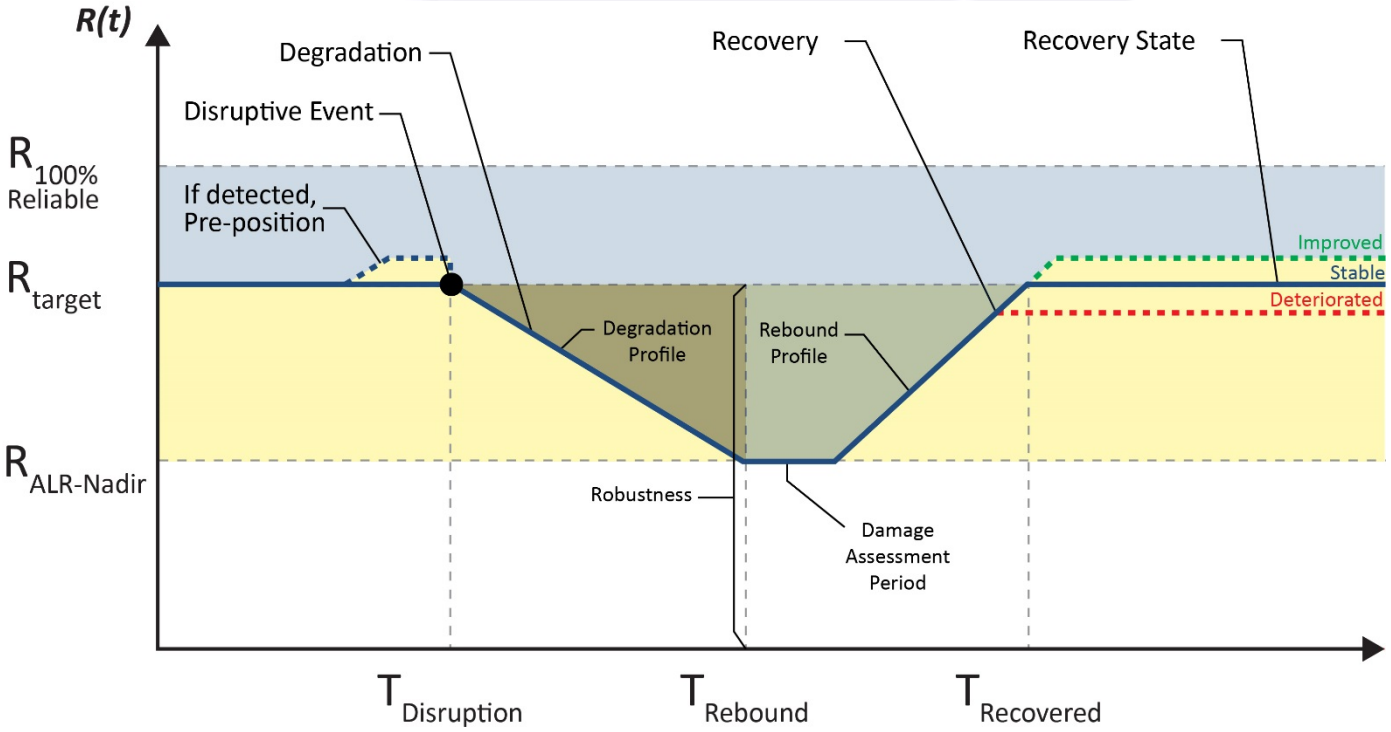
Discussion Items:

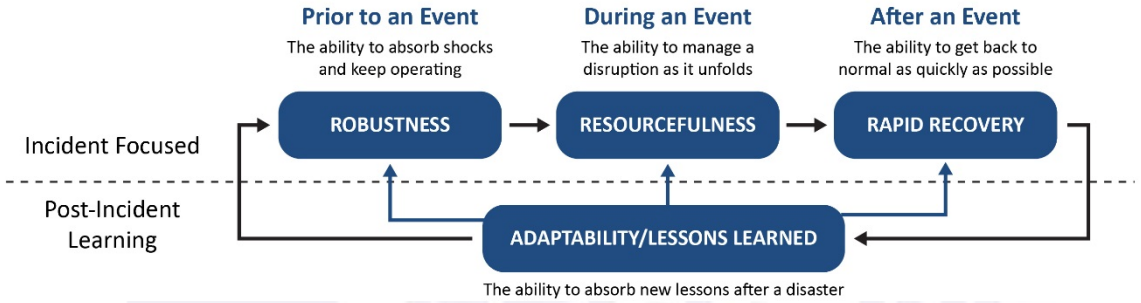
- RISC and Risk
- EPRI's Efforts
- HEMP
- Incident Command Structure
- DER
- U.S. DHS "SHARES"
- Physical Security

Resilience

- Four outcome-based abilities of resilience (framework) are as follows:
  - **Robustness** – the ability to absorb shocks and continue operating
  - **Resourcefulness** – the ability to detect and manage a crisis as it unfolds
  - **Rapid recovery** – the ability to get services back as quickly as possible in a coordinated and controlled manner and taking into consideration the extent of the damage
  - **Adaptability** – the ability to incorporate lessons learned from past events to improve resilience
- FERC -Top priority of the Commission address concerns- DOE Staff Report and NOPR
- FERC terminated the DOE NOPR and developed a FERC NOPR
  - what resilience of the bulk power system means and requires;
  - understand how each RTO and ISO assesses resilience in its geographic footprint; and
  - use this information to evaluate whether additional Commission action regarding resilience is appropriate at this time.
- RISC Report on Resilience

Resilience


R(t)
Degradation
Recovery
Recovery State
Disruptive Event
R 100% Reliable
If detected, Pre-position
Improved
Stable
Deteriorated
R target
Degradation Profile
Rebound Profile
R ALR-Nadir
Robustness
Damage Assessment Period
T Disruption
T Rebound
T Recovered


Prior to an Event
The ability to absorb shocks and keep operating
During an Event
The ability to manage a disruption as it unfolds
After an Event
The ability to get back to normal as quickly as possible
Incident Focused
ROBUSTNESS
RESOURCEFULNESS
RAPID RECOVERY
Post-Incident Learning
ADAPTABILITY/LESSONS LEARNED
The ability to absorb new lessons after a disaster

HEMP High Altitude Electromagnetic Pulse

- EPRI releasing a public report end of April 2019 (E1)
- Cost effective ways to protect the BES
- Focused on waveguides and simulations
- Fast surge arresters and filters and neutral blocking for transformers.
- It was implied that we can expect standards in this area.
- Executive Order outlining that work needs to be done to secure the grid from HEMP.

Incident Command Structure (ICS):

- ICS to coordinate response to natural and manmade disasters. ICS enables effective and efficient domestic incident management by integrating a combination of facilities, equipment, personnel, procedures, and communications operating within a common organizational structure.
- Unified command and clearly identifying and communicating boundaries and responsibilities
- Online Training- ICS Training - FEMA

Distributed Energy Resources (DER)

- Blackstart recovery and System Restoration
- Uncertain nature of DER to rely on as a resource
- Studies underway on use of DER for System Restoration
- Forecasting improvements have been improving
- Certain areas have a lot of PV, unused for UFLS and left offline during restoration until the system returns to a stable state.

U.S. DHS SHARES Radio System

- Shared high frequency radio system that utilizes a number of high frequencies for emergency use
- Developed for HEMP situations and Black Sky
- Useful range of 50 miles up to 1000 miles
- Obtained and applied for through the DHS. There is no license required. Link :

DHS Shared HF Radio

- 1,350 HF radio stations—representing 104 federal, state, and industry organizations, located in all 50 states, the District of Columbia, and overseas—participate in SHARES

Physical Security

- Main risk is Drones
- FAA does not allow them to be distrupted
- Unmanned Aircraft Restriction (UAC) Restricted Airspace
  - Stadiums and Sporting Events
  - Near Airports
  - Security Sensitive Airspace Restrictions
  - Restricted or Special Use Airspace
  - Washington, DC
- https://udds-faa.opendata.arcgis.com/ (Map)

“Intelligence is the ability to adapt to change.”-
Stephen Hawking

Questions or Comments ?

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

~~15-day informal comment period~~ This is the second draft of the proposed standard.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	04/18/2018
SAR posted for comment	03/19/18 – 03/28/18

Anticipated Actions	Date
~~XX~~45-day formal or informal comment period with ballot	11/26/2018 – 01/09/2019
~~XX~~45-day formal or informal comment period with additional ballot	TBD
~~XX~~10-day final ballot	TBD
Board adoption	TBD

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: Frequency Response and Frequency Bias Setting**
2. **Number: BAL-003-~~1.1~~2**
3. **Purpose:** To require sufficient Frequency Response from the Balancing Authority (BA) to maintain Interconnection Frequency within predefined bounds by arresting frequency deviations and supporting frequency until the frequency is restored to its scheduled value. To provide consistent methods for measuring Frequency Response and determining the Frequency Bias Setting.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Balancing Authority
       - **4.1.1.1.** Balancing Authority is the responsible entity unless the Balancing Authority is a member of a Frequency Response Sharing Group, in which case, the Frequency Response Sharing Group becomes the responsible entity.
     - **4.1.2.** Frequency Response Sharing Group
5. **Effective Date:** See Implementation Plan for BAL-003-~~1.1~~2.

B. Requirements and Measures

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]*

M1. Each Frequency Response Sharing Group or Balancing Authority that is not a member of a Frequency Response Sharing Group shall have evidence such as dated data plus documented formula in either hardcopy or electronic format that it achieved an annual FRM (in accordance with the methods specified by the ERO in Attachment A with data from FRS Form 1 reported to the ERO as specified in Attachment A) that is equal to or more negative than its FRO to demonstrate compliance with Requirement R1.

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]*

M2. The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service shall have evidence such as a dated document in hard copy or electronic format showing the ERO validated Frequency Bias Setting was implemented into its ACE calculation within the implementation period specified or other evidence to demonstrate compliance with Requirement R2.

R3. Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and is utilizing a variable Frequency Bias Setting shall maintain a Frequency Bias Setting that is: *[Risk Factor: Medium-][Time Horizon: Operations Planning]*

3.1 Less than zero at all times, and

3.2 Equal to or more negative than its Frequency Response Obligation when Frequency varies from 60 Hz by more than +/- 0.036 Hz.

M3. The Balancing Authority that is a member of a multiple Balancing Authority Interconnection, is not receiving Overlap Regulation Service and is utilizing variable Frequency Bias shall have evidence such as a dated report in hard copy or electronic format showing the average clock-minute average Frequency Bias Setting was less than zero and during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was equal to or more negative than its Frequency Response Obligation to demonstrate compliance with Requirement R3.

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.

M4. The Balancing Authority shall have evidence such as a dated operating log, database or list in hard copy or electronic format showing that when it performed Overlap Regulation Service, it modified its Frequency Bias Setting in its ACE calculation as specified in Requirement R4 to demonstrate compliance with Requirement R4.

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 Balancing Authority shall retain data or evidence to show compliance with Requirements R1, R2, R3 and R4, Measures M1, M2, M3 and M4 for the current year plus the previous three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- The Frequency Response Sharing Group shall retain data or evidence to show compliance with Requirement R1 and Measure M1 for the current year plus the previous three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- If a Balancing Authority or Frequency Response Sharing Group is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.
- The Compliance Enforcement Authority shall keep the last audit records and all subsequent requested and submitted records.

1.3. 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.

- For Interconnections that are also Balancing Authorities, Tie Line Bias control and flat frequency control are equivalent and either is acceptable.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 1% but by at most ~~30~~15% or 15 MW/0.1 Hz, whichever one is the greater deviation from its FRO.	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 15% but by at most 30% or by more than ~~15~~ 30 MW/0.1 Hz, whichever is the greater deviation from its FRO.	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than ~~1~~30% but by at most ~~30~~45% or ~~15~~ 45 MW/0.1 Hz, whichever one is the greater deviation from its FRO.	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than ~~30~~45% or by more than ~~15~~ 45 MW/0.1 Hz, whichever is the greater deviation from its FRO.
R2.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting failed to implement the validated Frequency Bias Setting value into its ACE calculation within the implementation period specified but did so within 5 calendar days from the implementation period specified by the ERO.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting implemented the validated Frequency Bias Setting value into its ACE calculation in more than 5 calendar days but less than or equal to 15 calendar days from the implementation period specified by the ERO.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting implemented the validated Frequency Bias Setting value into its ACE calculation in more than 15 calendar days but less than or equal to 25 calendar days from the implementation period specified by the ERO.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting did not implement the validated Frequency Bias Setting value into its ACE calculation in more than 25 calendar days from the implementation period specified by the ERO.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3.	The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 1% but by at most 10%.	The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 10% but by at most 20%.	The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 20% but by at most 30%.	The Balancing Authority that is a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response obligation by more than 30%.
R4.	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error less than or equal to 10% of the validated or calculated value.	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error more than 10% but less than or equal to 20% of the	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error more than 20% but less than or equal to 30% of the	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error more than 30% of the validated or calculated value. OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		validated or calculated value.	validated or calculated value.	The Balancing Authority failed to change the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services.

D. Regional Variances

None.

E. Associated Documents

~~Link to the Implementation Plan and other important associated documents.~~

Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard

FRS Form 1

FRS Form 2

Frequency Response Standard Background Document

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	March 16, 2007	FERC Approval — Order 693	New
0a	December 19, 2007	Added Appendix 1 — Interpretation of R3 approved by BOT on October 23, 2007	Addition
0a	July 21, 2008	FERC Approval of Interpretation of R3	Addition
0b	February 12, 2008	Added Appendix 2 — Interpretation of R2, R2.2, R5, and R5.1 approved by BOT on February 12, 2008	Addition
0.1b	January 16, 2008	Section F: added "1."; changed hyphen to "en dash." Changed font style for "Appendix 1" to Arial; updated version number to "0.1b"	Errata
0.1b	October 29, 2008	BOT approved errata changes	Errata
0.1a	May 13, 2009	FERC Approved errata changes – version changed to 0.1a (Interpretation of R2, R2.2, R5, and R5.1 not yet approved)	Errata
0.1b	May 21, 2009	FERC Approved Interpretation of R2, R2.2, R5, and R5.1	Addition
1	February 7, 2013	Adopted by NERC Board of Trustees	Complete Revision under Project 2007-12
1	January 16, 2014	FERC Order issued approving BAL-003-1. (Order becomes effective for R2, R3, and R4 April 1, 2015. R1 becomes effective April 1, 2016.)	
1	May 7, 2014	NERC Board of Trustees adopted revisions to VRF and VSLs in Requirement R1.	
1	November 26, 2014	FERC issued a letter order approved VRF and VSL revisions to Requirement R1.	
1.1	August 25, 2015	Added numbering to Introduction section, corrected parts numbering for R3, and adjusted font within section M4.	Errata

Version	Date	Action	Change Tracking
1.1	November 13, 2015	FERC Letter Order approved errata to BAL-003-1.1. Docket RD15-6-000	Errata

Standard Attachments

Attachment A

BAL-003-~~1~~ 2 Frequency Response ~~&~~ and Frequency Bias Setting Standard

Supporting Document

Interconnection Frequency Response Obligation ~~(IFRO)~~

The ERO, in consultation with regional representatives, has established a target ~~contingency protection criterion~~reliability ~~objective~~criterion for each Interconnection called the Interconnection Frequency Response Obligation (IFRO). ~~The default IFRO listed in Table 1 is based on the resource contingency criteria (RCC), w~~which is the largest category C (N-2) event identified except for the Eastern Interconnection, which uses the largest event in the last 10 years. A maximum delta frequency (MDF) is calculated by adjusting a starting frequency for each Interconnection by the following:

~~Prevailing UFLS first step~~

- ~~CC_{Adj} which is the adjustment for the differences between 1-second and sub-second Point C observations for frequency events. A positive value indicates that the sub-second C data is lower than the 1-second data~~
- ~~CB_R which is the statistically determined ratio of the Point C to Value B~~
- ~~BC'_{Adj} which is the statistically determined adjustment for the event nadir being below the Value B (Eastern Interconnection only) during primary frequency response withdrawal.~~

~~The IFRO for each Interconnection in Table 1 is then calculated by dividing the RCC MWs by 10 times the MDF. In the Eastern Interconnection there is an additional adjustment (BC'_{Adj}) for the event nadir being below the Value B due to primary frequency response withdrawal. This IFRO includes uncertainty adjustments at a 95 % confidence level.~~ Detailed descriptions of the calculations used in Table 1 below are defined in the Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard.

Interconnection	Eastern	Western	ERCOT	HQ	Units
~~Starting Frequency (F_{Start})~~	~~59.974~~	~~59.976~~	~~59.963~~	~~59.972~~	~~Hz~~
~~Prevailing UFLS First Step~~	~~59.5*~~	~~59.5~~	~~59.3~~	~~58.5~~	~~Hz~~
~~Base Delta Frequency (DF_{Base})~~	~~0.474~~	~~0.476~~	~~0.663~~	~~1.472~~	~~Hz~~
~~CC_{ADJ}~~	~~0.007~~	~~0.004~~	~~0.012~~	~~N/A~~	~~Hz~~
~~Delta Frequency (DF_{CC})~~	~~0.467~~	~~0.472~~	~~0.651~~	~~1.472~~	~~Hz~~
~~CB_R~~	~~1.000~~	~~1.625~~	~~1.377~~	~~1.550~~	
~~Delta Frequency (DF_{CBR})~~	~~0.467~~	~~0.291~~	~~0.473~~	~~0.949~~	~~Hz~~
~~BC'_{ADJ}~~	~~0.018~~	~~N/A~~	~~N/A~~	~~N/A~~	~~Hz~~
Max. Delta Frequency (MDF)	0.41~~949~~	0.28~~091~~	0.40~~673~~	0.94~~69~~	

Resource ~~Contingency~~ Loss Protection Criteria (RLP~~C~~C)*	**3~~4~~,209~~500~~**	**2,85~~74~~0**	**2,750**	**2~~1~~,0~~7~~00**	MW
Credit for Load Resources (CLR)		**120~~300~~**	**1,209,~~400~~****		MW
Current IFRO (OY 2018)	**-1,015**	**-858**	**-381**	**-179**	MW/0.1 Hz
First-Step IFRO**~~IFRO~~	**-915~~-1,002~~**	**-975~~840~~**	**-380~~286~~**	**-211~~179~~**	MW/0.1 Hz
Second-Step IFRO**	**-815**				
Final IFRO**	**-766**				

Table 1: Interconnection Frequency Response Obligations (base year)

**~~These values are updated using preliminary information collected by the Standard Drafting Team.~~*These values are evaluated annually for changes in each Interconnection.*

***To reduce risk, the Eastern Interconnection IFRO will be stepped down annually from the 2017 value of -1,015 MW/0.1 Hz in -100 MW/0.1 Hz increments. If during the step down process, Interconnection Frequency Response Measure (FRM) declines by more than 10~~%~~ percent, the ERO will halt the reduction in IFRO until such time~~s~~ that a determination can be made as to the cause of the degradation~~what is impacting Interconnection FRM~~.*

~~*The Eastern Interconnection UFLS set point listed is a compromise value set midway between the stable frequency minimum established in PRC-006-1 (59.3 Hz) and the local protection UFLS setting of 59.7 Hz used in Florida and Manitoba.*~~

~~***In the Base Obligation measure for ERCOT, 1400 MW (Load Resources triggered by Under Frequency Relays at 59.70 Hz) was reduced from its Resource Contingency Criteria level of 2750 MW to get 239 MW/0.1 Hz. This was reduced to accurately account for designed response from Load Resources within 30 cycles.*~~

~~An Interconnection may propose alternate IFRO protection criteria to the ERO by submitting a SAR with supporting technical documentation.~~

Balancing Authority Frequency Response Obligation ~~(FRO)~~ and Frequency Bias Setting

~~The ERO will manage the administrative procedure for annually assigning an FRO and implementation of the Frequency Bias Setting for each Balancing Authority. The annual timeline for all activities described in this section are shown below.~~

For a multiple Balancing Authority interconnection, the Interconnection FRO~~Frequency Response Obligation~~ shown in Table 1 is allocated based on the Balancing Authority annual load and annual generation. ~~-~~The FRO allocation will be based on the following method:

$$\mathrm{FRO}_{\mathrm{BA}} = \mathrm{IFRO} \quad \times \frac{\text{Annual Gen}_{\mathrm{BA}} + \text{Annual Load}_{\mathrm{BA}}}{\text{Annual Gen}_{\mathrm{Int}} + \text{Annual Load}_{\mathrm{Int}}}$$

Where:

- Annual $\mathrm{Gen}_{\mathrm{BA}}$ is the total annual ~~"~~o~~O~~utput of g~~G~~enerating p~~P~~lants~~"~~ within the Balancing Authority Area (BAA)~~., on FERC Form 714, column c of Part II - Schedule 3.~~
- Annual $\mathrm{Load}_{\mathrm{BA}}$ is total annual Load within the BAA~~, on FERC Form 714, column e of Part II - Schedule 3~~.
- Annual $\mathrm{Gen}_{\mathrm{Int}}$ is the sum of all Annual $\mathrm{Gen}_{\mathrm{BA}}$ values reported in that interconnection.
- Annual $\mathrm{Load}_{\mathrm{Int}}$ is the sum of all Annual $\mathrm{Load}_{\mathrm{BA}}$ values reported in that interconnection.

~~The data used for this calculation is from the most recently filed Form 714. As an example, a report to NERC in January 2013 would use the Form 714 data filed in 2012, which utilized data from 2011.~~

~~Balancing Authorities that are not FERC jurisdictional should use the Form 714 Instructions to assemble and submit equivalent data to the ERO for use in the FRO Allocation process.~~

Balancing Authorities that elect to form a FRSG will calculate a FRSG FRO by adding together the individual BA FRO's.

Balancing Authorities that elect to form a FRSG as a means to jointly meet the FRO will calculate their FRM performance one of two ways:

- Calculate a group NI_{A} and measure the group response to all events in the reporting year on a single FRS Form 1, or
- ~~Jointly submit the individual BAs' Form 1s, with a summary spreadsheet that contains the sum of each participant's individual event performance.~~ Submit a joint Form 1 with

the "FRSG" tab completed for the aggregate performance of the participating Balancing Authorities~~As~~.

Balancing Authorities that merge or ~~that~~ transfer load or generation are encouraged to notify the ERO of the change in footprint and corresponding changes in allocation such that the net obligation to the Interconnection remains the same and so that CPS limits can be adjusted.

Each Balancing Authority reports its previous year's ~~Frequency Response Measure (~~FRM~~)~~, Frequency Bias Setting and Frequency Bias type (fixed or variable) to the ERO each year to allow the ERO to validate the revised Frequency Bias Settings on FRS Form 1. In addition, each Balancing Authority will report its two largest potential resource losses and any applicable N-2 RAS events in the form. If the ERO posts the official list of events after the date specified in the timeline below, Balancing Authorities will be given 30 days from the date the ERO posts the official list of events to submit their FRS Form 1.

Once the ERO reviews the data submitted in FRS Form 1 and FRS Form 2 for all Balancing Authorities, the ERO will use FRS Form 1 data to post the following information for each Balancing Authority for the upcoming year:

- Frequency Bias Setting
- Frequency Response Obligation (FRO)

Once the data listed above is fully posted, the ERO will announce the three-day implementation period for changing the Frequency Bias Setting if it differs from that shown in the timeline below.

A Balancing Authority using a fixed Frequency Bias Setting sets its Frequency Bias Setting to the greater of (in absolute value):

- Any number the Balancing Authority chooses between 100~~%~~ percent and 125~~%~~ percent of its Frequency Response Measure as calculated on FRS Form 1
- Interconnection Minimum as determined by the ERO

For purposes of calculating the minimum Frequency Bias Setting, a Balancing Authority participating in a ~~Frequency Response Sharing Group~~FRSG will need to calculate its stand-alone ~~Frequency Response Measure~~FRM using FRS Form 1 and FRS Form 2 to determine its minimum Frequency Bias Setting.

A Balancing Authority providing Overlap Regulation will report the historic peak demand and generation of its combined Balancing Authorities' areas on FRS Form 1 as described in Requirement R4.

~~There are occasions when changes are needed to Bias Settings outside of the normal schedule. Examples are footprint changes between Balancing Authorities and major changes in load or generation or the formation of new Balancing Authorities. In such cases the changing Balancing Authorities will work with their Regions, NERC and the Resources Subcommittee to confirm appropriate changes to Bias Settings, FRO, CPS limits and Inadvertent Interchange balances.~~

~~If there is no net change to the Interconnection total Bias, the Balancing Authorities involved will agree on a date to implement their respective change in Bias Settings. The Balancing Authorities and ERO will also agree to the allocation of FRO such that the sum remains the same.~~

~~If there is a net change to the Interconnection total Bias, this will cause a change in CPS2 limits and FRO for other Balancing Authorities in the Interconnection. In this case, the ERO will notify the impacted Balancing Authorities of their respective changes and provide an implementation window for making the Bias Setting changes.~~

~~The ERO, in consultation with regional representatives, has established a target contingency protection criterion for each Interconnection called the Interconnection Frequency Response Obligation (IFRO). Detailed descriptions of the IFRO calculations are defined in the Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard.~~[1]

Frequency Response Measure ~~(FRM)~~

The Balancing Authority will calculate its FRM from Single Event Frequency Response Data (SEFRD), defined as: "the data from an individual event ~~from~~ in a Balancing Authority area that is used to calculate its Frequency Response, expressed in MW/0.1Hz" as calculated on FRS Form 2 for each event shown on FRS Form 1. The events in FRS Form 1 are selected by the ERO using the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*. The SEFRD for a typical Balancing Authority in an Interconnection with more than one Balancing Authority is ~~basically~~ the change in its Net Actual Interchange on its tie lines with ~~its~~ adjacent Balancing Authorities divided by the change in Interconnection frequency. ~~(~~Some Balancing Authorities may choose to apply corrections to their Net Actual Interchange (NA_I) values to account for factors such as nonconforming loads. FRS Form 1 and 2 shows the types of adjustments that are allowed. Note that with the exception of the Contingent BA column, any adjustments made must be made for all events in an evaluation year.[2] ~~As an example, if an entity has non-conforming loads and makes an adjustment for one event, all events must show the non-conforming load, even if the non-conforming load does not impact the calculation. This ensures that the reports are not utilizing the adjustments only when they are favorable to the BA.)~~

The ERO will use a standardized sampling interval of approximately 16 seconds before the event, up to the time of the event for the pre-event NA_I, and frequency (A values), and approximately 20 to 52 seconds after the event for the post-event NA_I (B values) in the computation of SEFRD values, dependent on the data scan rate of the Balancing Authority's Energy Management System (EMS).

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[1] ~~Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard is available at https://www.nerc.com/pa/Stand/Frequency%20Response%20Project%20200712%20Related%20Files%20DL/BAL-003-1_Procedure-Clean_20120210.pdf~~

[2] As an example, if an entity has non-conforming loads and makes an adjustment for one event, all events must show the non-conforming load, even if the non-conforming load does not impact the calculation. This ensures that the reports are not utilizing the adjustments only when they are favorable to the BA.

All events listed on FRS Form 1 need to be included in the annual submission of FRS Forms 1 and 2. The only time a Balancing Authority should exclude an event is if its tie-line data or its Frequency data is corrupt, or its EMS was unavailable. FRS Form 2 has instructions on how to correct the BA's data if the given event is internal to the BA or if other authorized adjustments are used.

Assuming data entry is correct, FRS Form 1 will automatically calculate the Balancing Authority's FRM for the past 12 months as the median of the SEFRD values. A Balancing Authority electing to report as an FRSG or a provider of Overlap Regulation Service will provide an FRS Form 1 for the aggregate of its participants.

To allow Balancing ~~authorities~~ Authorities to plan its operations, events with a "Point C" that cause the Interconnection Frequency to be lower than that shown in Table 1 above (for example, an event in the Eastern Interconnection that causes the Interconnection Frequency to go to 59.4 Hz) or higher than an equal change in frequency going above 60 Hz may be included in the list of events for that ~~interconnection~~Interconnection. However, the calculation of the Balancing Authority response to such an event will be adjusted to show a frequency change only to the Target Minimum Frequency shown in Table 1 above (in the previous example this adjustment would cause Frequency to be shown as 59.5 Hz rather than 59.4 HZ) or a high frequency amount of an equal quantity. Should such an event happen, the ERO will provide additional guidance.

Balancing Authorities that elect to form a FRSG as a means to jointly meet the FRO will calculate their FRM performance one of two ways:

- Calculate a group NI_A and measure the group response to all events in the reporting year on a single FRS Form 1, or
- Jointly submit the individual Balancing Authority's Form 1s, with a summary spreadsheet that contains the sum of each participant's individual event performance.

Timeline for Balancing Authority Frequency Response and Frequency Bias Setting Activities

Described below is the timeline for the exchange of information between the ERO and Balancing Authorities ~~(BA)~~ to:

- Facilitate the assignment of Balancing Authority ~~Frequency Response Obligations (~~FRO~~)~~
- Calculate Balancing Authority ~~Frequency Response Measures (~~FRM~~)~~
- Determine Balancing Authority A Frequency Bias Settings ~~(FBS)~~

Target Business Date	Activity
~~April 30~~March 1	FRS Form 1 is posted by ~~The~~ the ERO* with all selected events for the operating year for BA usage~~reviews candidate frequency events and selects frequency events for the first quarter (December to February)~~.
April 1	BAs and FRSGs complete their frequency response forms for all four quarters, including the BAs' FBS calculations, returning the results to the ERO.
May 1	The ERO validates FBS values, computes the sum of all FBS values for each Interconnection.
~~May 10~~	~~Form1 is posted with selected events from the first quarter for BA usage by the ERO.~~
May 15	The BAs not required to file FERC Form 714 receive a request to provide load and generation data as described in the ***Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard***** to support FRO assignments and determining minimum FBS for the upcoming year. Data to be provided by July 15.~~The BAs receive a request to provide load and generation data as described in Attachment A to support FRO assignments and determining minimum FBS for BAs.~~
June 1	The BA implements any changes to their FBS.
November 1	The ERO assigns FRO values and Minimum FBS for the upcoming year to the BAs.

* If 4th quarter posting of FRS Form 1s is delayed, the ERO may adjust the other timelines in this table by a similar amount.

** Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard

Formatted: Normal

~~Rationale~~

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

~~Rationale for R1:~~

~~Text, text, text~~

~~Rationale for R2:~~

~~Text, text, text~~

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 second draft of the proposed standard.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	04/18/2018
SAR posted for comment	03/19/2018 – 03/28/2018

Anticipated Actions	Date
45-day formal or informal comment period with ballot	11/26/2018 – 01/09/2019
45-day formal or informal comment period with additional ballot	TBD
10-day final ballot	TBD
Board adoption	TBD

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: Frequency Response and Frequency Bias Setting**

2. **Number: BAL-003-2**

3. **Purpose:** To require sufficient Frequency Response from the Balancing Authority (BA) to maintain Interconnection Frequency within predefined bounds by arresting frequency deviations and supporting frequency until the frequency is restored to its scheduled value. To provide consistent methods for measuring Frequency Response and determining the Frequency Bias Setting.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Balancing Authority

   4.1.1.1. Balancing Authority is the responsible entity unless the Balancing Authority is a member of a Frequency Response Sharing Group, in which case, the Frequency Response Sharing Group becomes the responsible entity.

   4.1.2. Frequency Response Sharing Group

5. **Effective Date:** See Implementation Plan for BAL-003-2.

B. Requirements and Measures

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]*

M1. Each Frequency Response Sharing Group or Balancing Authority that is not a member of a Frequency Response Sharing Group shall have evidence such as dated data plus documented formula in either hardcopy or electronic format that it achieved an annual FRM (in accordance with the methods specified by the ERO in Attachment A with data from FRS Form 1 reported to the ERO as specified in Attachment A) that is equal to or more negative than its FRO to demonstrate compliance with Requirement R1.

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]*

M2. The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service shall have evidence such as a dated document in hard copy or electronic format showing the ERO validated Frequency Bias Setting was implemented into its ACE calculation within the implementation period specified or other evidence to demonstrate compliance with Requirement R2.

R3. Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and is utilizing a variable Frequency Bias Setting shall maintain a Frequency Bias Setting that is: *[Risk Factor: Medium][Time Horizon: Operations Planning]*

3.1 Less than zero at all times, and

3.2 Equal to or more negative than its Frequency Response Obligation when Frequency varies from 60 Hz by more than +/- 0.036 Hz.

M3. The Balancing Authority that is a member of a multiple Balancing Authority Interconnection, is not receiving Overlap Regulation Service and is utilizing variable Frequency Bias shall have evidence such as a dated report in hard copy or electronic format showing the average clock-minute average Frequency Bias Setting was less than zero and during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was equal to or more negative than its Frequency Response Obligation to demonstrate compliance with Requirement R3.

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.

M4. The Balancing Authority shall have evidence such as a dated operating log, database or list in hard copy or electronic format showing that when it performed Overlap Regulation Service, it modified its Frequency Bias Setting in its ACE calculation as specified in Requirement R4 to demonstrate compliance with Requirement R4.

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 Balancing Authority shall retain data or evidence to show compliance with Requirements R1, R2, R3 and R4, Measures M1, M2, M3 and M4 for the current year plus the previous three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- The Frequency Response Sharing Group shall retain data or evidence to show compliance with Requirement R1 and Measure M1 for the current year plus the previous three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- If a Balancing Authority or Frequency Response Sharing Group is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.
- The Compliance Enforcement Authority shall keep the last audit records and all subsequent requested and submitted records.

1.3. 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.

- For Interconnections that are also Balancing Authorities, Tie Line Bias control and flat frequency control are equivalent and either is acceptable.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 1% but by at most 15% or 15 MW/0.1 Hz, whichever one is the greater deviation from its FRO.	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 15% but by at most 30% or by more than 30 MW/0.1 Hz, whichever is the greater deviation from its FRO.	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 30% but by at most 45% or 45 MW/0.1 Hz, whichever one is the greater deviation from its FRO.	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 45% or by more than 45 MW/0.1 Hz, whichever is the greater deviation from its FRO.
R2.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting failed to implement the validated Frequency Bias Setting value into its ACE calculation within the implementation period specified but did so within 5 calendar days from the implementation period specified by the ERO.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting implemented the validated Frequency Bias Setting value into its ACE calculation in more than 5 calendar days but less than or equal to 15 calendar days from the implementation period specified by the ERO.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting implemented the validated Frequency Bias Setting value into its ACE calculation in more than 15 calendar days but less than or equal to 25 calendar days from the implementation period specified by the ERO.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting did not implement the validated Frequency Bias Setting value into its ACE calculation in more than 25 calendar days from the implementation period specified by the ERO.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3.	The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 1% but by at most 10%.	The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 10% but by at most 20%.	The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 20% but by at most 30%.	The Balancing Authority that is a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response obligation by more than 30%.
R4.	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error less than or equal to 10% of the validated or calculated value.	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error more than 10% but less than or equal to 20% of the	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error more than 20% but less than or equal to 30% of the	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error more than 30% of the validated or calculated value. OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		validated or calculated value.	validated or calculated value.	The Balancing Authority failed to change the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services.

D. Regional Variances

None.

E. Associated Documents

Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard

FRS Form 1

FRS Form 2

Frequency Response Standard Background Document

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	March 16, 2007	FERC Approval — Order 693	New
0a	December 19, 2007	Added Appendix 1 — Interpretation of R3 approved by BOT on October 23, 2007	Addition
0a	July 21, 2008	FERC Approval of Interpretation of R3	Addition
0b	February 12, 2008	Added Appendix 2 — Interpretation of R2, R2.2, R5, and R5.1 approved by BOT on February 12, 2008	Addition
0.1b	January 16, 2008	Section F: added “1.”; changed hyphen to “en dash.” Changed font style for “Appendix 1” to Arial; updated version number to “0.1b”	Errata
0.1b	October 29, 2008	BOT approved errata changes	Errata
0.1a	May 13, 2009	FERC Approved errata changes – version changed to 0.1a (Interpretation of R2, R2.2, R5, and R5.1 not yet approved)	Errata
0.1b	May 21, 2009	FERC Approved Interpretation of R2, R2.2, R5, and R5.1	Addition
1	February 7, 2013	Adopted by NERC Board of Trustees	Complete Revision under Project 2007-12
1	January 16, 2014	FERC Order issued approving BAL-003-1. (Order becomes effective for R2, R3, and R4 April 1, 2015. R1 becomes effective April 1, 2016.)	
1	May 7, 2014	NERC Board of Trustees adopted revisions to VRF and VSLs in Requirement R1.	
1	November 26, 2014	FERC issued a letter order approved VRF and VSL revisions to Requirement R1.	
1.1	August 25, 2015	Added numbering to Introduction section, corrected parts numbering for R3, and adjusted font within section M4.	Errata

Version	Date	Action	Change Tracking
1.1	November 13, 2015	FERC Letter Order approved errata to BAL-003-1.1. Docket RD15-6-000	Errata

Standard Attachments

Attachment A

BAL-003-2 Frequency Response and Frequency Bias Setting Standard

Supporting Document

Interconnection Frequency Response Obligation

The ERO, in consultation with regional representatives, has established a target reliability criterion for each Interconnection called the Interconnection Frequency Response Obligation (IFRO). Detailed descriptions of the calculations used in Table 1 below are defined in the Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard.

Interconnection	Eastern	Western	ERCOT	HQ	Units
Max. Delta Frequency (MDF)	**0.419**	**0.280**	**0.406**	**0.946**	
Resource Loss Protection Criteria (RLPC)*	**3,209**	**2,850**	**2,750**	**2,000**	MW
Credit for Load Resources (CLR)		**120**	**1,209**		MW
Current IFRO (OY 2018)	**-1,015**	**-858**	**-381**	**-179**	MW/0.1 Hz
First-Step IFRO**	**-915**	**-975**	**-380**	**-211**	MW/0.1 Hz
Second-Step IFRO**	**-815**				
Final IFRO**	**-766**				

Table 1: Interconnection Frequency Response Obligations (base year)

**These values are evaluated annually for changes in each Interconnection.*

***To reduce risk, the Eastern Interconnection IFRO will be stepped down annually from the 2017 value of -1,015 MW/0.1 Hz in -100 MW/0.1 Hz increments. If during the step down process, Interconnection Frequency Response Measure (FRM) declines by more than 10 percent, the ERO will halt the reduction in IFRO until such time that a determination can be made as to the cause of the degradation.*

Balancing Authority Frequency Response Obligation and Frequency Bias Setting

For a multiple Balancing Authority interconnection, the Interconnection FRO shown in Table 1 is allocated based on the Balancing Authority annual load and annual generation. The FRO allocation will be based on the following method:

$$\text{FRO}_{\text{BA}} = \text{IFRO} \quad \times \frac{\text{Annual Gen}_{\text{BA}} + \text{Annual Load}_{\text{BA}}}{\text{Annual Gen}_{\text{Int}} + \text{Annual Load}_{\text{Int}}}$$

Where:

- Annual Gen_{BA} is the total annual output of generating plants within the Balancing Authority Area (BAA).
- Annual Load_{BA} is total annual Load within the BAA.
- Annual Gen_{Int} is the sum of all Annual Gen_{BA} values reported in that interconnection.
- Annual Load_{Int} is the sum of all Annual Load_{BA} values reported in that interconnection.

Balancing Authorities that elect to form a FRSG will calculate a FRSG FRO by adding together the individual BA FRO's.

Balancing Authorities that elect to form a FRSG as a means to jointly meet the FRO will calculate their FRM performance one of two ways:

- Calculate a group NI_{A} and measure the group response to all events in the reporting year on a single FRS Form 1, or
- Submit a joint Form 1 with the "FRSG" tab completed for the aggregate performance of the participating Balancing Authorities.

Balancing Authorities that merge or transfer load or generation are encouraged to notify the ERO of the change in footprint and corresponding changes in allocation such that the net obligation to the Interconnection remains the same and so that CPS limits can be adjusted.

Each Balancing Authority reports its previous year's FRM, Frequency Bias Setting and Frequency Bias type (fixed or variable) to the ERO each year to allow the ERO to validate the revised Frequency Bias Settings on FRS Form 1. In addition, each Balancing Authority will report its two largest potential resource losses and any applicable N-2 RAS events in the form. If the ERO posts the official list of events after the date specified in the timeline below, Balancing Authorities will be given 30 days from the date the ERO posts the official list of events to submit their FRS Form 1.

Once the ERO reviews the data submitted in FRS Form 1 and FRS Form 2 for all Balancing Authorities, the ERO will use FRS Form 1 data to post the following information for each Balancing Authority for the upcoming year:

- Frequency Bias Setting
- Frequency Response Obligation (FRO)

Once the data listed above is fully posted, the ERO will announce the three-day implementation period for changing the Frequency Bias Setting if it differs from that shown in the timeline below.

A Balancing Authority using a fixed Frequency Bias Setting sets its Frequency Bias Setting to the greater of (in absolute value):

- Any number the Balancing Authority chooses between 100 percent and 125 percent of its Frequency Response Measure as calculated on FRS Form 1
- Interconnection Minimum as determined by the ERO

For purposes of calculating the minimum Frequency Bias Setting, a Balancing Authority participating in a FRSG will need to calculate its stand-alone FRM using FRS Form 1 and FRS Form 2 to determine its minimum Frequency Bias Setting.

A Balancing Authority providing Overlap Regulation will report the historic peak demand and generation of its combined Balancing Authorities' areas on FRS Form 1 as described in Requirement R4.

Frequency Response Measure

The Balancing Authority will calculate its FRM from Single Event Frequency Response Data (SEFRD), defined as: "the data from an individual event in a Balancing Authority area that is used to calculate its Frequency Response, expressed in MW/0.1Hz" as calculated on FRS Form 2 for each event shown on FRS Form 1. The events in FRS Form 1 are selected by the ERO using the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*. The SEFRD for a typical Balancing Authority in an Interconnection with more than one Balancing Authority is the change in its Net Actual Interchange on its tie lines with adjacent Balancing Authorities divided by the change in Interconnection frequency. Some Balancing Authorities may choose to apply corrections to their Net Actual Interchange (NA_I) values to account for factors such as nonconforming loads. FRS Form 1 and 2 shows the types of adjustments that are allowed. Note that with the exception of the Contingent BA column, any adjustments made must be made for all events in an evaluation year.[1]

The ERO will use a standardized sampling interval of approximately 16 seconds before the event, up to the time of the event for the pre-event NA_I, and frequency (A values), and approximately 20 to 52 seconds after the event for the post-event NA_I (B values) in the computation of SEFRD values, dependent on the data scan rate of the Balancing Authority's Energy Management System (EMS).

All events listed on FRS Form 1 need to be included in the annual submission of FRS Forms 1 and 2. The only time a Balancing Authority should exclude an event is if its tie-line data or its Frequency data is corrupt, or its EMS was unavailable. FRS Form 2 has instructions on how to

[1] As an example, if an entity has non-conforming loads and makes an adjustment for one event, all events must show the non-conforming load, even if the non-conforming load does not impact the calculation. This ensures that the reports are not utilizing the adjustments only when they are favorable to the BA.

correct the BA's data if the given event is internal to the BA or if other authorized adjustments are used.

Assuming data entry is correct, FRS Form 1 will automatically calculate the Balancing Authority's FRM for the past 12 months as the median of the SEFRD values. A Balancing Authority electing to report as an FRSG or a provider of Overlap Regulation Service will provide an FRS Form 1 for the aggregate of its participants.

To allow Balancing Authorities to plan its operations, events with a "Point C" that cause the Interconnection Frequency to be lower than that shown in Table 1 above (for example, an event in the Eastern Interconnection that causes the Interconnection Frequency to go to 59.4 Hz) or higher than an equal change in frequency going above 60 Hz may be included in the list of events for that Interconnection. However, the calculation of the Balancing Authority response to such an event will be adjusted to show a frequency change only to the Target Minimum Frequency shown in Table 1 above (in the previous example this adjustment would cause Frequency to be shown as 59.5 Hz rather than 59.4 HZ) or a high frequency amount of an equal quantity. Should such an event happen, the ERO will provide additional guidance.

Balancing Authorities that elect to form a FRSG as a means to jointly meet the FRO will calculate their FRM performance one of two ways:

- Calculate a group NI_A and measure the group response to all events in the reporting year on a single FRS Form 1, or
- Jointly submit the individual Balancing Authority's Form 1s, with a summary spreadsheet that contains the sum of each participant's individual event performance.

Timeline for Balancing Authority Frequency Response and Frequency Bias Setting Activities

Described below is the timeline for the exchange of information between the ERO and Balancing Authorities to:

- Facilitate the assignment of Balancing Authority FRO
- Calculate Balancing Authority FRM
- Determine Balancing Authority Frequency Bias Settings

Target Business Date	Activity
March 1	FRS Form 1 is posted by the ERO* with all selected events for the operating year for BA usage.
April 1	BAs and FRSGs complete their frequency response forms for all four quarters, including the BAs' FBS calculations, returning the results to the ERO.
May 1	The ERO validates FBS values, computes the sum of all FBS values for each Interconnection.
May 15	The BAs not required to file FERC Form 714 receive a request to provide load and generation data as described in the ***Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard***** to support FRO assignments and determining minimum FBS for the upcoming year. Data to be provided by July 15.
June 1	The BA implements any changes to their FBS.
November 1	The ERO assigns FRO values and Minimum FBS for the upcoming year to the BAs.

* If 4th quarter posting of FRS Form 1s is delayed, the ERO may adjust the other timelines in this table by a similar amount.

** Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard

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Implementation Plan

Project 2017-01 Modifications to BAL-003-1.1
Reliability Standard BAL-003-2

Applicable Standard

- Standard BAL-003-2 — Frequency Response and Frequency Bias Setting

Requested Retirement(s)

- Standard BAL-003-1.1 — Frequency Response and Frequency Bias Setting

Applicable Entities

- Balancing Authority
  - Balancing Authority is the responsible entity unless the Balancing Authority is a member of a Frequency Response Sharing Group, in which case, the Frequency Response Sharing Group becomes the responsible entity.
- Frequency Response Sharing Group

Background

The BAL-003-2 Phase I portion of the project revises the BAL-003-1.1 standard and process documents to address: (1) the inconsistencies in calculation of IFROs due to interconnection Frequency Response performance changes of Point C and/or Value B; (2) the Eastern Interconnection Resource Contingency Protection Criteria; (3) the frequency of nadir point limitations (currently limited to t0 to t+12); (4) clarification of language in Attachment A, i.e. related to Frequency Response Reserve Sharing Groups (FRSG) and the timeline for Frequency Response and Frequency Bias Setting activities; and (5) enhancements to the BAL-003-1 FRS Forms that include the ability to collect and submit FRSG performance data. Additionally, the supporting procedural and process steps have been removed from Attachment A and captured in the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard.* This proposed document would be subject to approval by the North American Electric Reliability Corporation Operating Committee and Board of Trustees, and subject to informational filing with the Federal Energy Regulatory Commission, to facilitate timely process improvements as future lessons are learned.

Effective Date

BAL-003-2 — Frequency Response and Frequency Bias Setting

Where approval by an applicable governmental authority is required, the standard shall become effective on the first operating year (which begins on December 1) that is 90 days 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 operating year (which begins on December 1) that is 90 days after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

BAL-003-1.1 — Frequency Response and Frequency Bias Setting
Reliability Standard BAL-003-1.1 shall be retired immediately prior to the effective date of BAL-003-2 in the particular jurisdiction in which the revised standard is becoming effective.

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Violation Risk Factor and Violation Severity Level Justifications

Project 2017-01 Modifications to BAL-003-1.1

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 BAL-003-2. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements. Please note, the SDT is only proposing to change the VSL for Requirement R1. As a result, justification is only provided for the VSL for Requirement R1

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, 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; 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 BES instability, separation, or a cascading sequence of failures, or could place the BES 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 BES, or the ability to effectively monitor and control the BES. However, violation of a medium risk requirement is unlikely to lead to BES 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 BES, or the ability to effectively monitor, control, or restore the BES. However, violation of a medium risk 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.

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 BES, or the ability to effectively monitor and control the BES; 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 BES, or the ability to effectively monitor, control, or restore the BES.

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 (BPS). In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the BPS

- 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 BAL-003-1.1, Requirement R1
The VRF did not change from the previously FERC approved BAL-003-1.1 Reliability Standard.

VSL Justification for BAL-003-1.1, Requirement R1
This justification is provided on the following page.

VRF Justification for BAL-003-1.1, Requirement R2
The VRF did not change from the previously FERC approved BAL-003-1.1 Reliability Standard.

VSL Justification for BAL-003-1.1, Requirement R2
The VSL did not change from the previously FERC approved BAL-003-1.1 Reliability Standard.

VRF Justification for BAL-003-1.1, Requirement R3
The VRF did not change from the previously FERC approved BAL-003-1.1 Reliability Standard.

VSL Justification for BAL-003-1.1, Requirement R3
The VSL did not change from the previously FERC approved BAL-003-1.1 Reliability Standard.

VRF Justification for BAL-003-1.1, Requirement R4
The VRF did not change from the previously FERC approved BAL-003-1.1 Reliability Standard.

VSL Justification for BAL-003-1.1, Requirement R4
The VSL did not change from the previously FERC approved BAL-003-1.1 Reliability Standard.

VSLs for BAL-003-2, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
The Balancing Authority's (BA)s, or Frequency Response Sharing Group's (FRSG)s, Frequency Response Measure (FRM) was less negative than its Frequency Response Obligation (FRO) by more than 1% but by at most 15% or 15 MW/0.1 Hz, whichever one is the greater deviation from its FRO.	The BA's, or (FRSG)s, FRM was less negative than its FRO by more than 15% but by at most 30% or by more than 30 MW/0.1 Hz, whichever is the greater deviation from its FRO.	The BA's, or FRSGs, FRM was less negative than its FRO by more than 30% but by at most 45% or 45 MW/0.1 Hz, whichever one is the greater deviation from its FRO.	The BA's, or FRSG's, FRM was less negative than its FRO by more than 45% or by more than 45 MW/0.1 Hz, whichever is the greater deviation from its FRO.

VSL Justifications for BAL-003-2, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This is not applicable since there was not a requirement mandating a certain level of Frequency Response prior to this standard.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Proposed VSL's are not binary. Proposed VSL language does not include ambiguous terms and ensures uniformity and consistency in the determination of penalties based only on the amount the calculated FRM is less negative than FRO.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Proposed VSL's do not expand on what is required. The VSL's assigned only consider results of the calculation required. Proposed VSL's are consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

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Frequency Response Standard Background Document

November, 2012

RELIABILITY | ACCOUNTABILITY

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Introduction

This document provides background on the development, testing and implementation of BAL-003-1 - Frequency Response Standard ("FRS").[1] The intent is to explain the rationale and considerations for the Requirements of this standard and their associated compliance information. The document also provides good practices and tips for Balancing Authorities ("BAs") with regard to Frequency Response.

In Order No. 693, the Federal Energy Regulatory Commission ("FERC" or the "Commission") directed additional changes to BAL-003.[2] This document explains how compliance with those directives are met by BAL-003-1.

The original Standards Authorization Request ("SAR"), finalized on June 30, 2007, assumed there was adequate Frequency Response in all the North American Interconnections. The goal of the SAR was to update the Standard to make the measurement process of frequency response more objective and to provide this objective data to Planners and Operators for improved modeling. The updated models will improve understanding of the trends in Frequency Response to determine if reliability limits are being approached. The Standard would also lay the process groundwork for a transition to a performance-based Standard if reliability limits are approached.

This document will be periodically updated by the FRS Drafting Team ("FRSDT") until the Standard is approved. Once approved, this document will then be maintained and updated by the ERO and the NERC Resources Subcommittee to be used as a reference and training resource.

Background

This section discusses the different components of frequency control and the individual components of Primary Frequency Control also known as Frequency Response.

Frequency Control

Most system operators generally have a good understanding of frequency control and Bias Setting as outlined in the balancing standards and the references to them in the NERC Operating Manual. Frequency control can be divided into four overlapping windows of time as outlined below.

> **Primary Frequency Control (Frequency Response) –** Actions provided by the Interconnection to arrest and stabilize frequency in response to frequency deviations.

[1] Unless otherwise designated herein, all capitalized terms shall have the meaning set forth in the Glossary of Terms Used in NERC Reliability Standards, available here: http://www.nerc.com/files/Glossary_of_Terms.pdf.

[2] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242 at PP 368-375, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

Primary Control comes from automatic generator governor response (also known as speed regulation), load response (typically from motors), and other devices that provide an immediate response based on local (device-level) control systems.

Secondary Frequency Control – Actions provided by an individual BA or its Reserve Sharing Group to correct the resource – load unbalance that created the original frequency deviation, which will restore both Scheduled Frequency and Primary Frequency Response. Secondary Control comes from either manual or automated dispatch from a centralized control system.

Tertiary Frequency Control – Actions provided by Balancing Authorities on a balanced basis that are coordinated so there is a net zero effect on Area Control Error (ACE). Examples of Tertiary Control include dispatching generation to serve native load; economic dispatch; dispatching generation to affect Interchange; and re-dispatching generation. Tertiary Control actions are intended to replace Secondary Control Response by reconfiguring reserves.

Time Control includes small offsets to scheduled frequency to keep long term average frequency at 60 Hz.

Primary Frequency Control – Frequency Response

Primary Frequency Control, also known generally as **Frequency Response**, is the first stage of overall frequency control and is the response of resources and load to a locally sensed change in frequency in order to arrest that change in frequency. Frequency Response is automatic, not driven by any centralized system, and begins within seconds rather than minutes. Different resources, loads, and systems provide Frequency Response with different response times, based on current system conditions such as total resource/load and their respective mix.

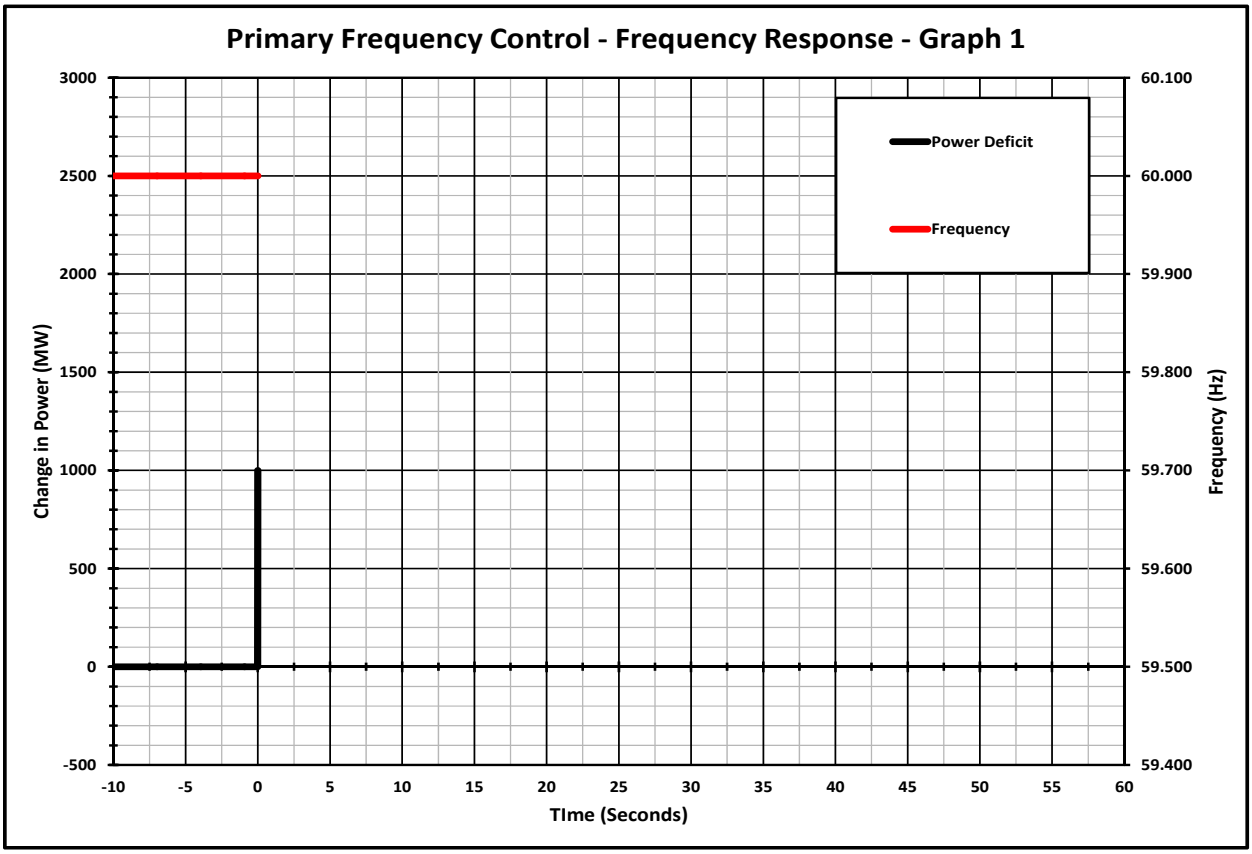
The proposed NERC Glossary of Terms defines **Frequency Response** as:

- (Equipment) The immediate and automatic reaction or response of power from a system or power from elements of the system to a change in locally sensed system frequency.
- (System) The sum of the change in demand, and the change in generation, divided by the change in frequency, expressed in megawatts per 0.1 Hertz (MW/0.1 Hz).

As noted above, Frequency Response is the characteristic of load and generation within Balancing Authorities and Interconnections. It reacts or responds with changes in power to attempted changes in load-resource balance that result in changes to system frequency. Because the loss of a large generator is much more likely than a sudden loss of an equivalent amount of load, Frequency Response is typically discussed in the context of a loss of a large generator. Included within Frequency Response are many components of that response. Understanding Frequency Response and the FRS requires an understanding of each of these components and how they relate to each other.

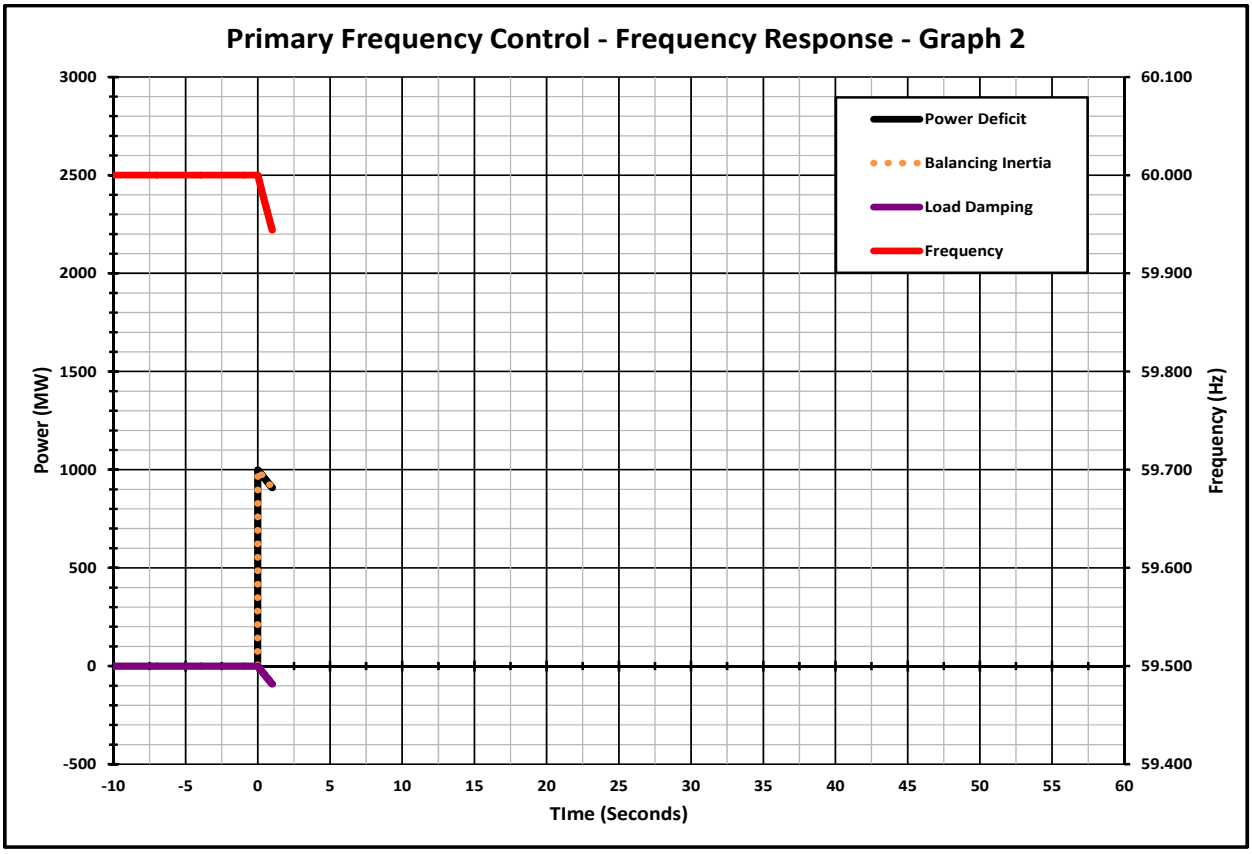
Frequency Response Illustration

The following simple example is presented to illustrate the components of Frequency Response in graphical form. It includes a series of seven graphs that illustrate the various components of Frequency Response and a brief discussion of each describing how these components react to attempted changes in the load-resource balance and resulting changes in system frequency. The illustration is based on an assumed Disturbance event of the sudden loss of 1000 MW of generation. Although a large event is used to illustrate the response components, even small frequently occurring events will result in similar reactions or responses. The magnitude of the event only affects the shape of the curves on the graph; it does not obviate the need for Frequency Response.



The first graph, Primary Frequency Control – Frequency Response – Graph 1, presents a sudden loss of generation of 1000 MW. The components are presented relative to time as shown on the horizontal Time axis in seconds. This simplified example assumes a Disturbance event of the sudden loss of generation resulting from a breaker trip that instantaneously removes 1000 MW of generation from the interconnection. This sudden loss is illustrated by the power deficit line shown in black using the MW scale on the left. Interconnection frequency is illustrated by the frequency line shown in red using the Hertz scale on the right. Since the Scheduled Frequency is normally 60 Hz, it is assumed that this is the frequency when the Disturbance event occurs.

Even though the generation has tripped and power injected by the generator has been removed from the interconnection, the loads continue to use the same amount of power. The "Law of Conservation of Energy"[3] requires that the 1000 MW must be supplied to the interconnection if energy balance is to be "conserved." This additional 1000 MW of power is produced by extracting kinetic energy that was stored in the rotating mass of all of the synchronized generators and motors on the interconnection – essentially using this equipment as a giant flywheel. The extracted energy supplies the "balancing inertia"[4] power required to maintain the power and energy balance on the interconnection. This balancing inertia power is produced by the generators' spinning inertial mass' resistance to the slowdown in speed of the rotating equipment on the interconnection that both provides the stored kinetic energy and reduces the frequency of the interconnection. This is illustrated in the second graph, Primary Frequency Control – Frequency Response – Graph 2, by the orange dots representing the balancing inertia power that exactly overlay and offset the power deficit.



As the frequency decreases, synchronized motors slow, as does the work they are providing, resulting in a decrease in load called "load damping." This load damping is the reason that the power deficit initially declines. Synchronously operated motors will contribute to load

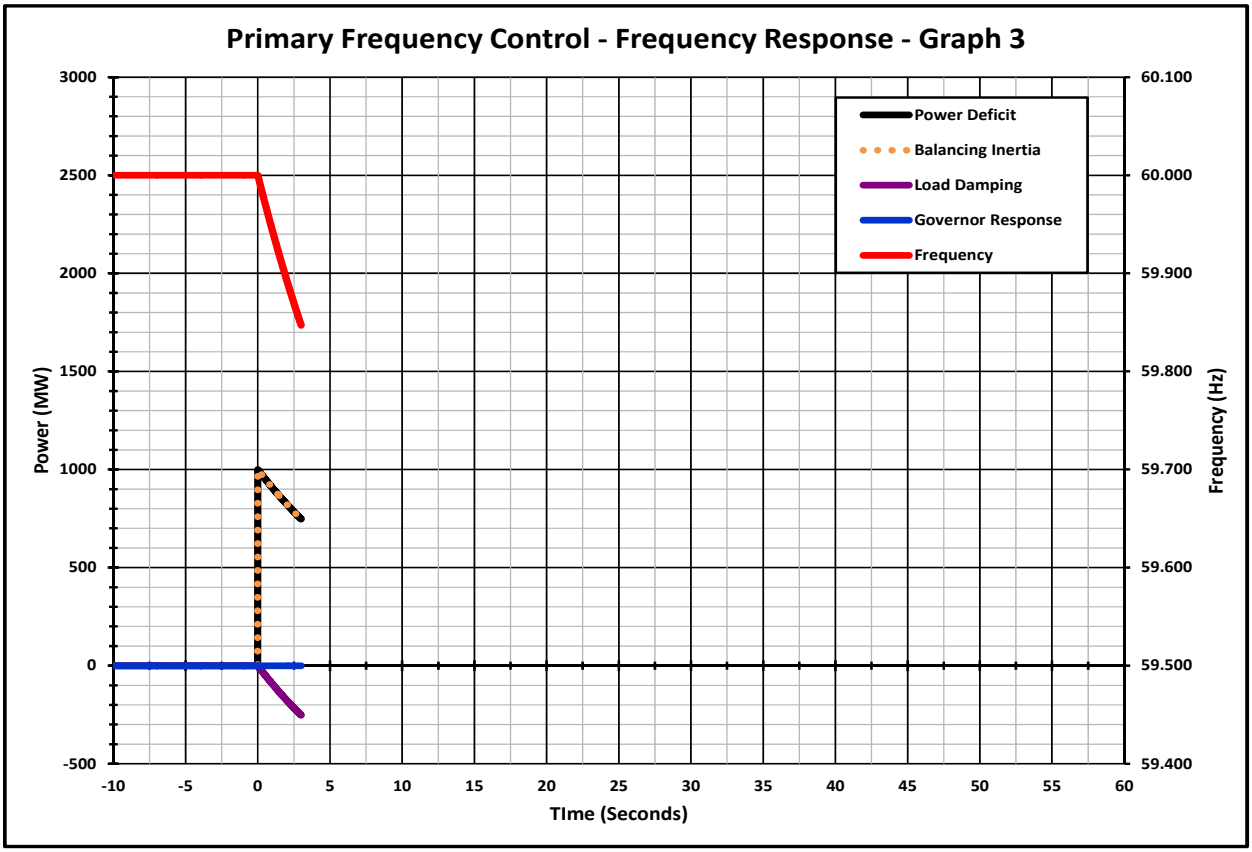
[3] The "Law of Conservation of Energy" is applied here in the form of power. If energy must be conserved, then power which is the first derivative of energy with respect to time, must also be conserved.

[4] The term "balancing Inertia" is coined here from the terms "inertial frequency response" and "balancing energy". Inertial frequency response is a common term used to describe the power supplied for this portion of the frequency response and balancing energy is a term used to describe the market energy supposedly purchased to restore energy balance.

damping. Variable speed drives that are decoupled from the interconnection frequency do not contribute to load damping. In general, any load that does not change with interconnection frequency including resistive load will not contribute to load damping or Frequency Response.

It is important to note that the power deficit equals exactly the balancing inertia, indicating that there is no power or energy imbalance at any time during this process. What is normally considered as "balancing power or energy" is actually power or energy required to correct the frequency error from scheduled frequency. Any apparent power or energy imbalance is corrected instantaneously by the balancing inertia power and energy extracted from the interconnection. Thus the balancing function is really a frequency control function described as a balancing function because ACE is calculated in MWs instead of Hertz, frequency error.

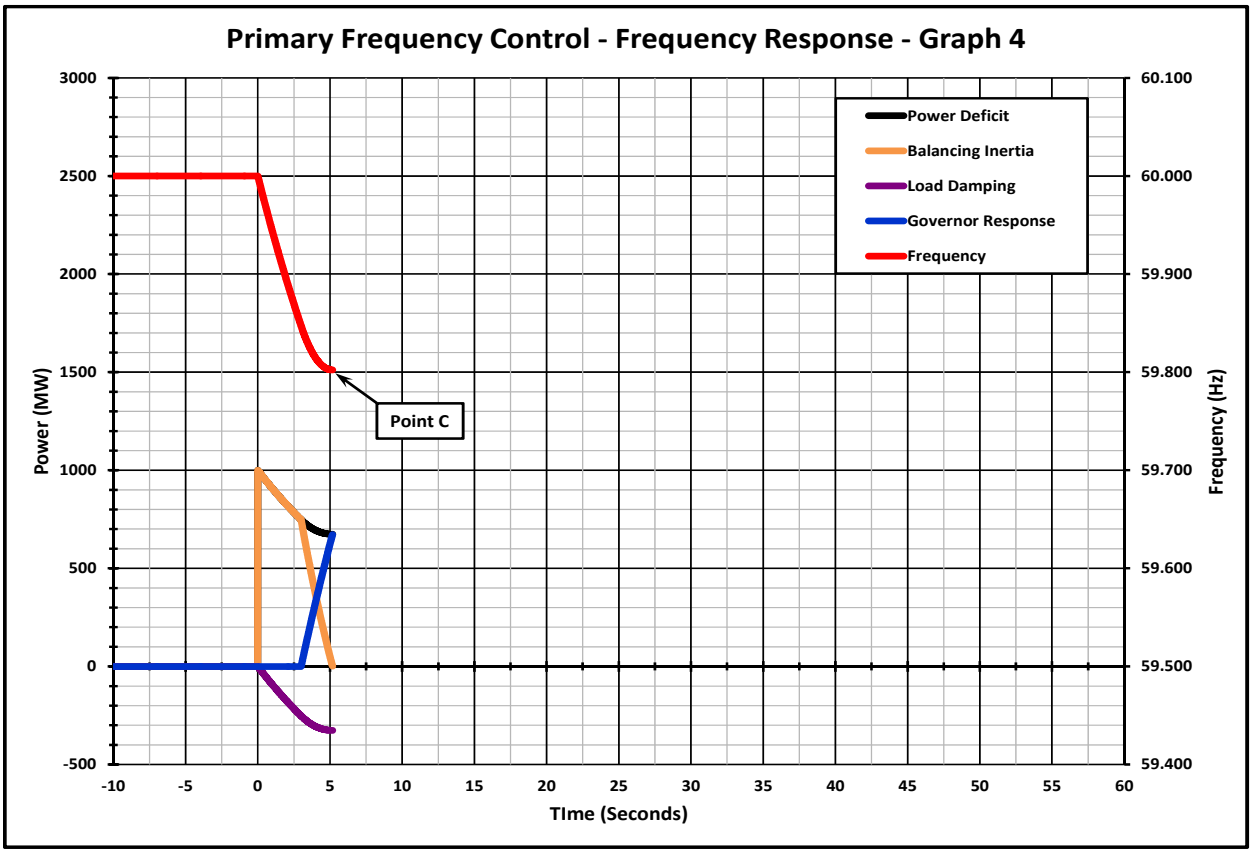
During the initial seconds of the Disturbance event, the governors have yet to respond to the frequency decline. This is illustrated with the Blue line on the third graph, Primary Frequency Control – Frequency Response – Graph 3, showing Governor Response. This time delay results from the time that it takes the controller to adjust the equipment and the time it takes the mass to flow from the source of the energy (main steam control valve for steam turbines, the combustor for gas turbines, or the gate valve for hydro turbines) to the turbine-generator blades where the power is converted to electrical energy.



Note that the frequency continues to decline due to the ongoing extraction by balancing inertia power of energy from the rotating turbine-generators and synchronous motors on the

interconnection. The reduction in load also continues as the effect of load damping continues to reduce the load while frequency declines. During this time delay (before the governor response begins) the balancing inertia limits the rate of change of frequency.

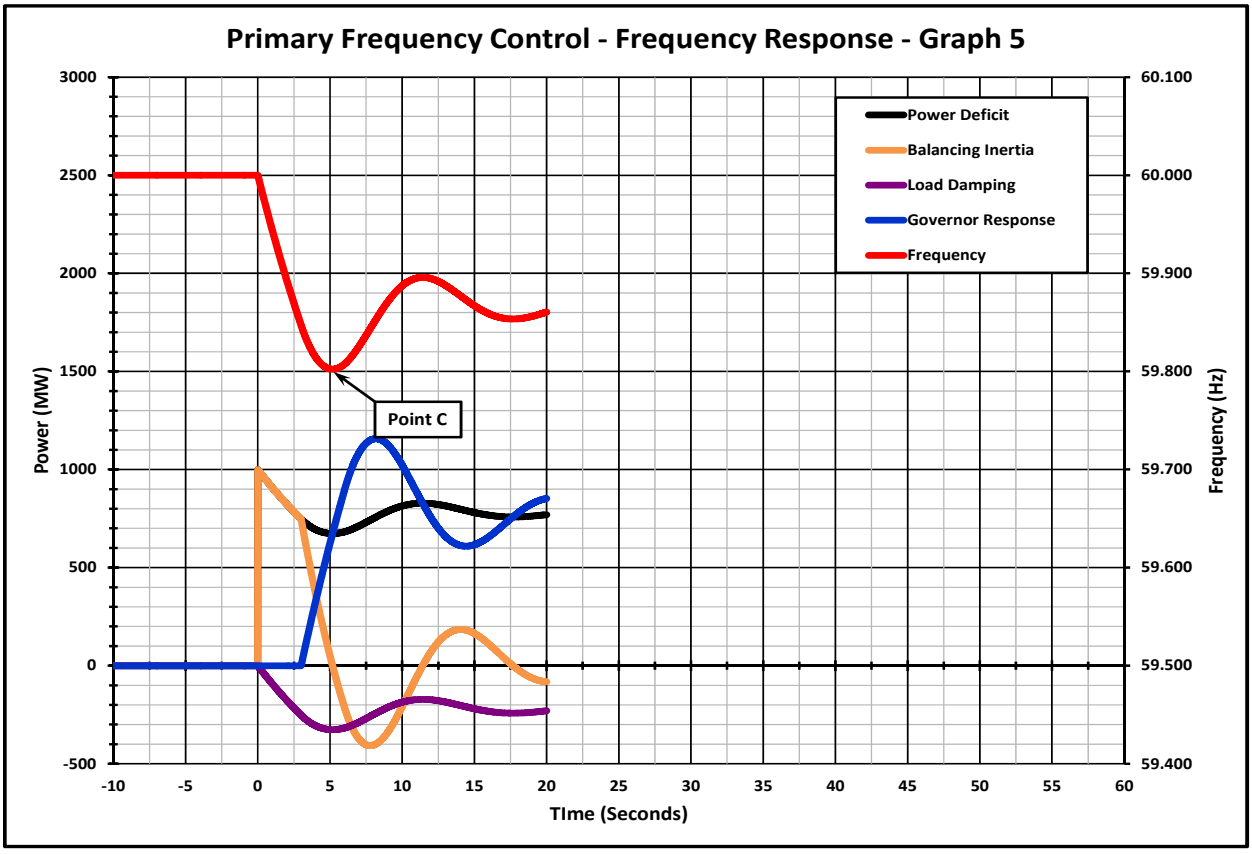
After a short time delay, the governor response begins to increase rapidly in response to the initial rapid decline in frequency, as illustrated on the fourth graph, Primary Frequency Control – Frequency Response – Graph 4. Governor response exactly offsets the power deficit at the point in time that the frequency decline is arrested. At this point in time, the balancing inertia has provided its contribution to reliability and its power contribution is reduced to zero as it is replaced by the governor response. If the time delay associated with the delivery of governor response is reduced, the amount of balancing inertia required to limit the change in frequency by the Disturbance event can also be reduced. This supports the conclusion that balancing inertia is required to manage the time delays associated with the delivery of Frequency Response. Not only is the rapid delivery of Frequency Response important, but the shortening of the time delay associated with its delivery is also important. Therefore, two important components of Frequency Response are 1) how long the time delay is before the initial delivery of response begins; and 2) how much of the response is delivered before the frequency change is arrested.



This point, at which the frequency is first arrested, is defined as "Point C" and Frequency Response calculated at this point is called the "**arrested frequency response**." The arrested

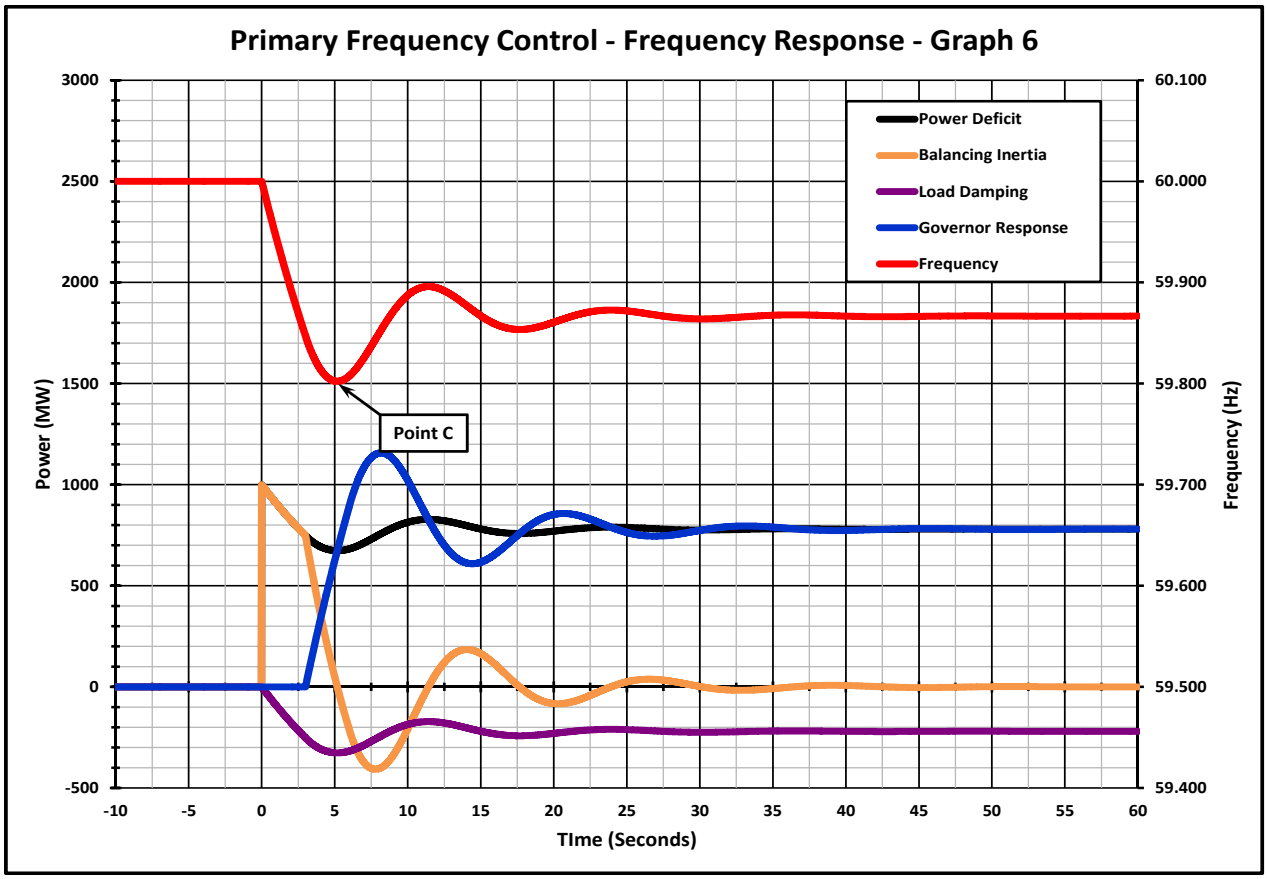
frequency is normally the minimum (maximum for load loss events) frequency that will be experienced during a Disturbance event. From a reliability perspective, this minimum frequency is the frequency that is of concern. Adequate reliability requires that frequency at the time frequency is arrested remain above the under-frequency relay settings so as not to trip these relays and the firm load interrupted by them. Frequency Response delivered after frequency is arrested at this minimum level provides less reliability value than Frequency Response delivered before Point C, but greater value than Secondary Frequency Control power and energy which is delivered minutes later.

Once the frequency decline is arrested, the governors continue to respond because of the time delay associated with their Governor Response. This results in the frequency partially recovering from the minimum arrested value and results in an oscillating transient that follows the minimum frequency (arrested frequency) until power flows and frequency settle during the transient period that ends roughly 20 seconds after the Disturbance event. This post-disturbance transient period is included on the fifth illustrative graph, Primary Frequency Control – Frequency Response – Graph 5.

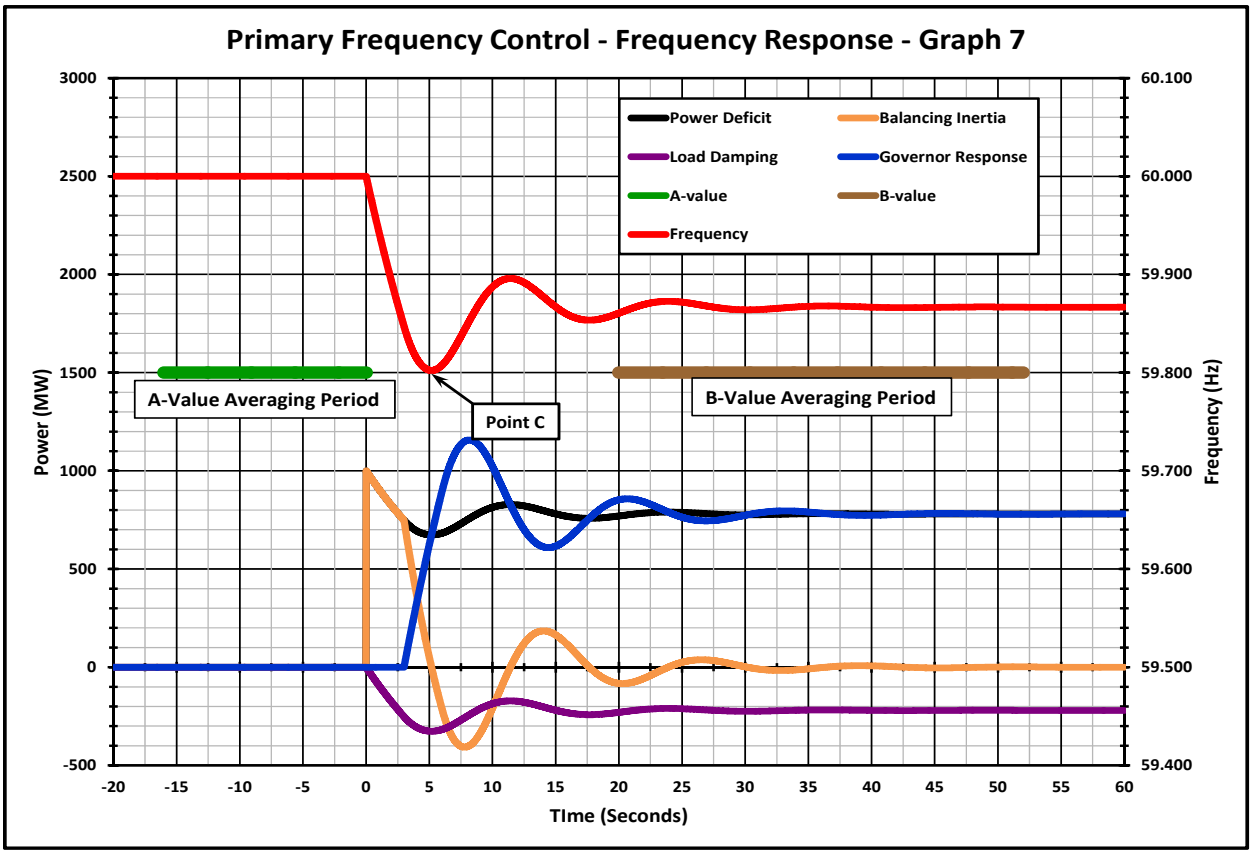


The total Disturbance event illustration is presented on the sixth graph, Primary Frequency Control – Frequency Response – Graph 6. Frequency and power contributions stabilize at the end of the transient period. Frequency Response calculated from data measured during this

settled period is called the “Settled Frequency Response.” The Settled Frequency Response is the best measure to use as an estimator for the “Frequency Bias Setting” discussed later.



The final Disturbance event illustration is presented on the seventh graph, Primary Frequency Control – Frequency Response – Graph 7. This graph shows the averaging periods used to estimate the pre-disturbance A-Value averaging period and the post-disturbance B-Value averaging period used to calculate the settled frequency response. A discussion of the measurement of Frequency Response immediately follows these graphs. That discussion includes consideration of the factors that affect the methods chosen to measure Frequency Response for implementation in a reliability standard.



Frequency Response Measurement (FRM)

The classic Frequency Response points A, C, and B, shown below in Fig. 1 Frequency Response Characteristic, are used for measurement as found in the Frequency Response Characteristic Survey Training Document within the NERC operating manual, found at http://www.nerc.com/files/opman_7-1-11.pdf. This traditional Frequency Response Measure has recently been more specifically termed "**settled frequency response**." This term has been used because it provides the best Frequency Response Measure to estimate the Frequency Bias Setting in Tie-line Bias Control based Automatic Generation Control Systems. However, the industry has recognized that there is considerable variability in measurement resulting from the selection of Point A and Point B in the traditional measure making the traditional measurement method unsuitable as the basis for an enforceable reliability standard in a real world setting of multiple Balancing Authority interconnections.

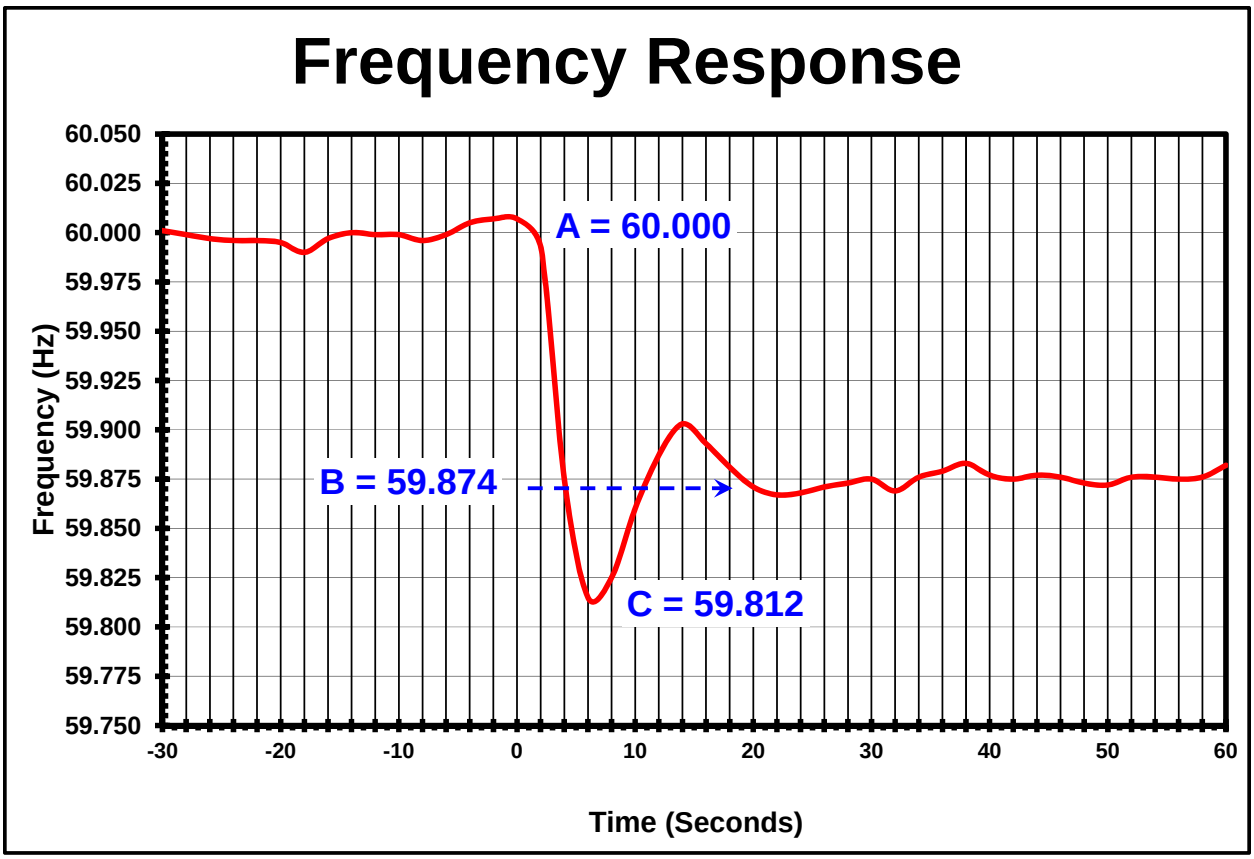


Figure 1. Frequency Response Characteristic

By contrast, measuring an Interconnection's settled frequency response is straightforward and fairly accurate. All that's needed to make the calculation is to know the size of a given contingency (MW), divide this value by the change in frequency and multiply the results by 10 since frequency response is expressed in MW/0.1Hz.

Measuring a BA's frequency response is more challenging. Prior to BAL-003-1, NERC's *Frequency Response Characteristic Survey Training Document* provided guidance to calculate Frequency Response. In short, it told the reader to identify the BA's interchange values "immediately before" and "immediately after" the Disturbance event and use the difference to calculate the MWs the BA deployed for the event. There are two challenges with this approach:

- Two people looking at the same data would come up with different values when assessing which exact points were immediately before and after the event.
- In practice, the actual response provided by the BA can change significantly in the window of time between point B and when secondary and tertiary control can assist in recovery.

Therefore, the measurement of settled frequency response has been standardized in a number of ways to limit the variability in measurement resulting from the poorly specified selection of Point A and Point B. It should be noted that t-0 has been defined as the first scan value that

shows a deviation in frequency of some significance, usually approaching about 10 mHz. The goal is such that the first scan prior to t-0 was unaffected by the deviation and appropriate for one of the averaging points.

- The A-value averaging period of approximately the previous 16 seconds prior to t-0 was selected to allow for an averaging of at least 2 scans for entities utilizing 6 second scan rates. (All time average period references in this document are for 2 second scan rates unless noted otherwise.)
- The B-value averaging period of approximately (t+20 to t+52 seconds) was selected to attempt to obtain the average of the data after primary frequency response was deployed and the transient completed(settled), but before significance influence of secondary control. Multiple periods were considered for averaging the B-value:
    - 12 to 24 sec
    - 18 to 30 sec
    - 20 to 40 sec
    - 18 to 52 sec
    - 20 to 52 sec

  It is necessary for all BAs from an interconnection to use the same averaging periods to provide consistent results. In addition, the SDT decided that until more experience is gained, it is also desirable for all interconnections to use the same averaging periods to allow comparison between interconnections.

The methods presented in this document only address the values required to calculate the frequency response associated with the frequency change between the initial frequency, A-Value, and the settling frequency, B-Value. No reasonable or consistent calculations can be made relating to the arresting frequency, C-Value, using Energy Management System (EMS) scan rate data as long as 6-seconds or tie-line flow values associated with the minimum value of the frequency response characteristic (C-value) as measured at the BA level.

Both the calculation of the frequency at Point A and the frequency at Point B began with the assumption that a 6-second scan rate was the source of the data. Once the averaging periods for a 6-second scan rate were selected, the averaging periods for the other scan rates were selected to provide as much consistency as possible between BAs with different scan rates.

The Frequency at Point A was initially defined as the average of the two scans immediately prior to the frequency event. All other averaging periods were selected to be as consistent as possible with this 12 second average scan from the 6-second scan rate method. In addition, the "**actual net interchange immediately before Disturbance**" is defined as the average of the same scans as used for the Point A frequency average.

The Frequency at Point B was then selected to be an average as long as the average of 6-second scan data as possible that would not begin until most of the hydro governor response had been delivered and would end before significant Automatic Generation Control (AGC) recovery response had been initiated as indicated by a consistent frequency restoration slope. The "**actual net interchange immediately after Disturbance**" is defined as the average of the same scans as used for the Point B frequency average.

B Averaging Period Selection:

Experience from the Electric Reliability Council of Texas ("ERCOT") and the field trail on other interconnections indicated that the 12 to 24 second and 18 to 30 second averaging periods were not suitable because they did not provide the consistency in results that the other averaging periods provided, and that the remaining measuring periods do not provide significantly different results from each other. The team believed that this was observed because the transients were not complete in all of the samples using these averaging periods.

The 18 to 52 second and 20 to 52 second averaging periods were compared to each other, with the 20 to 52 second period providing more consistent values, believed to result from the incomplete transient in some of the 18 to 52 second samples.

This left a choice between the 20 to 40 second and the 20 to 52 second averaging periods. The team recognized that there would be more AGC response in the 20 to 52 second period, but the team also recognized that the 20 to 52 second period would provide a better measure of squelched response from outer loop control action. The 20 to 52 second period was selected because it would indicate squelched response from outer-loop control and provide incentive to reduce response withdrawal. The final selections for the data averaging periods used in FRS Form 1 are shown in the table below.

Definitions of Frequency Values for Frequency Response Calculation

Scan Rate	T 0 Scan	A Value (average)	B Value (average)
6-Seconds	Identify first significant change in frequency as the T 0 scan	Average of T-1 through T-2 scans	Average of T+4 through T+8 scans
5-Seconds		Average of T-1 through T-2 scans	Average of T+5 through T+10 scans
4-Seconds		Average of T-1 through T-3 scans	Average of T+6 through T+12 scans
3-Seconds		Average of T-1 through T-5 scans	Average of T+7 through T+17 scans
2-Seconds		Average of T-1 through T-8 scans	Average of T+10 through T+26 scans

Consistent measurement of Primary Frequency Response is achievable for a selected number of events and can produce representative frequency response values, provided an appropriate sample size is used in the analysis. Available research investigating the minimum sample size to provide consistent measurements of Frequency Response has shown that a minimum sample size of 20 events should be adequate.

Measurement of Primary Frequency Response on an individual resource or load basis requires analysis of energy amounts that are often small and difficult to measure using current methods. In addition, the number of an interconnection's resources and loads providing their response could be problematic when compiling results for multiple events.

Measurement of Primary Frequency Response on an interconnection (System) basis is straight forward provided that an accurate frequency metering source is available and the magnitude of the resource/load imbalance is known in MWs.

Measurement on a Balancing Authority basis can be a challenge, since the determination of change in MWs is determined by the change in the individual BA's metered tie lines. Summation of tie lines is accomplished by summing the results of values obtained by the digital scanning of meters at intervals up to six seconds, resulting in a non-coincidental summing of values. Until the technology to GPS time stamp tie line values at the meter and the summing of those values for coincidental times is in use throughout the industry, it is necessary to use averaging of values described above to obtain consistent results.

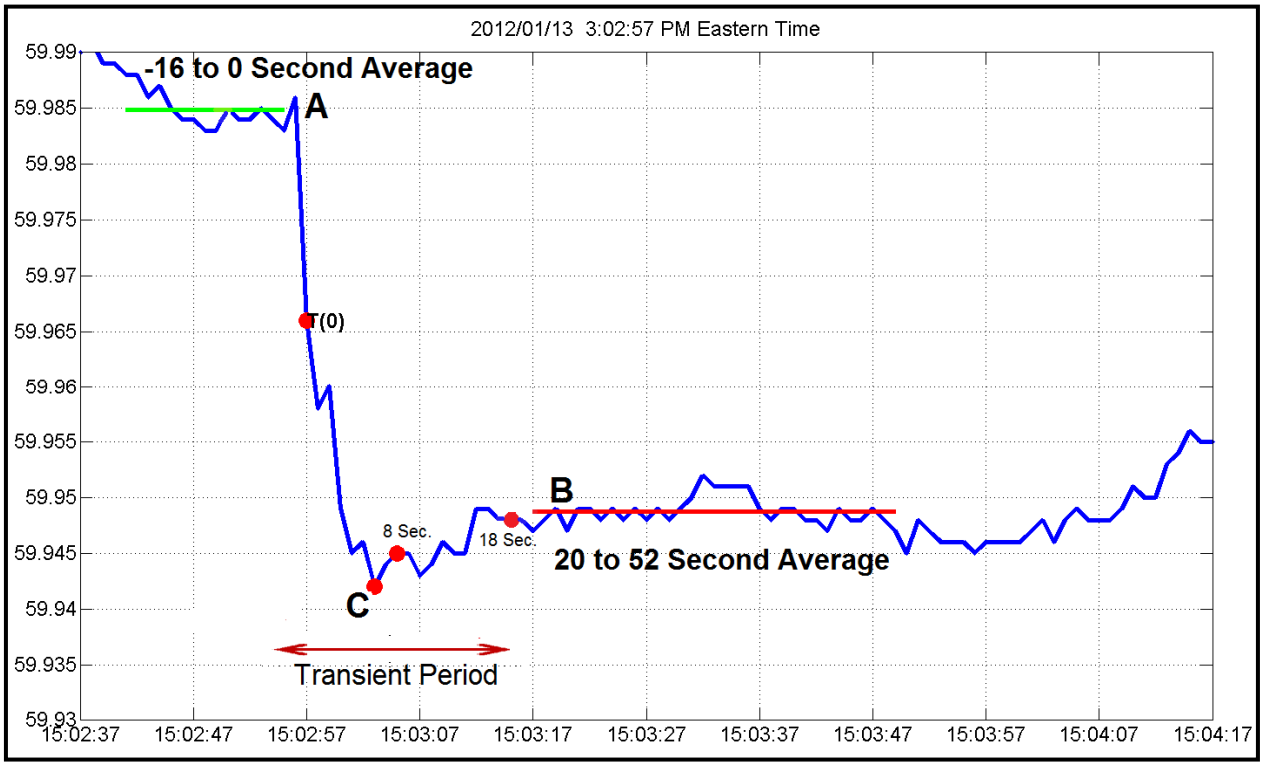


Figure 2. Frequency Response Measurement

The standardized measure is shown graphically in Fig. 2 Frequency Response Measurement with the averaging periods shown by the solid green and red lines on the graph. Since FERC directed a performance obligation for BAL-003-1, it is important to be more objective in the measurement process. The standardized calculation is available on FRS Form 2 for EMS scan rates of 2, 3, 4, 5, and 6 seconds at http://www.nerc.com/filez/standards/Frequency_Response.html.

Arrested Frequency Response

There is another measure of Frequency Response that is of interest when developing a Frequency Response estimate that not only will be used for estimating the Frequency Bias Setting, but will also be used to assure reliability by operating in a manner that will bound interconnection frequency and prevent the operation of Under-frequency Relays. This Frequency Response Measure has recently been named "**arrested frequency response.**" This Frequency Response is significantly affected by the inertial Frequency Response, the governor Frequency Response and the time delays associated with the delivery of governor Frequency

Response. It is calculated by using the change in frequency between the initial frequency, A, and the maximum frequency change during the event, C, instead of using the change between A and B. Arrested Frequency Response is the correct response for determining the minimum Frequency Response related to under-frequency relay operation and the support of interconnection reliability. This is because it can be used to provide a direct estimate of the maximum frequency deviation an interconnection will experience for an initial frequency and a given size event in MW. Unfortunately, arrested frequency response cannot currently be measured using the existing EMS-based measurement infrastructure. This limitation exists because the scan rates currently used in industry EMSs are incapable of measuring the net actual interchange at the same instant that the maximum frequency deviation is reached. Fortunately, the ratio of arrested frequency response and settled frequency response tends to be stable on an interconnection. This allows the settled frequency response value to be used as a surrogate for the arrested frequency response and implement a reasonable measure upon which to base a standard. One consequence of using the settled frequency response as a surrogate for the arrested frequency response is the inclusion of a large reliability margin in Interconnection Frequency Response Obligation to allow for the difference between the settled frequency response as measured and the arrested frequency response that indicates reliability.

As measurement infrastructure improves one might expect the Frequency Response Obligation to transition to a measurement based directly on the arrested frequency response while the Frequency Bias Setting will continue to be based on the settled frequency response. However, at this time, the measurement devices and methods in use do not support the necessary level of accuracy to estimate arrested frequency response contribution for an individual Balancing Authority.

Frequency Response Definition and Examples

Limitations of the measurement infrastructure determine the measurement methods recommended in this standard. The measurement limitations provide opportunities to improve the Frequency Response as measured in the standard without contributing to an improvement in Frequency Response that contributes to reliability. These definitions and examples provide a basis for determining which contributions to Frequency Response contribute the most to improved reliability. They also provide the basis for determining on a case by case basis whether the individual contributors to the Frequency Response Measure are also contributing to reliability.

General Frequency Response Characteristics

In the simplest case Frequency Response includes any automatic response to changes in local frequency. If that response works to decrease that change in frequency, it is beneficial to reliability. If that response works to increase that change in frequency, it is detrimental to reliability. However, this definition does not address the relative value of one response as compared to other responses that may be provided in a specific case.

There are numerous characteristics associated with the Frequency Response that affect the reliability value and economic value of the response. These characteristics include:

1. **Inertial** – the response is inertial or approximates inertial response

Inertial response provides power without delay that is proportional to the frequency and the change in frequency. Therefore, power provided by electronic control as synthetic Inertial response must be proportional to the frequency and change in frequency and be provided without a time delay.

2. **Immediate** – no unnecessary intentional time delays or reduction in the rate of response delivery
    a. time delay before the beginning of the response
    Turbines that convert heat or kinetic energy have time delays related to the time delay from the time that the control valves are moved to initiate the change in power and the time that the power is delivered to the generator. These times are usually associated with the time it takes a change in mass flow to travel from the control valve to the first blades of the turbine in the turbine generator.

    b. reduction in the rate of response delivery
    There are natural delays associated with the rate of response delivery that are related to the mass flow travel from the first turbine blades to the last turbine blades. In addition, some turbines have intentional delays designed into the control system to slow the rate of change in the delivery of the kinetic energy or fuel to the turbine to prevent the turbine or other equipment from being damaged, hydro turbines, or to prevent the turbine from tripping due to excessive rate of change, gas turbines.

3. **Proportional** – the amount of the total response is proportional to the frequency error
    a. No Deadband – the response is proportional across the entire frequency range
    b. Deadband – the response is only proportional outside of a defined deadband

4. **Bi-directional** – the response occurs to both increases and decreases in frequency

5. **Continuous** – there are no discontinuities in the delivery of the response (no step changes)

6. **Sustained** – the response is sustained until frequency is returned to schedule

Frequency Response Reliability Value

This section contains a more detailed discussion of the various characteristics of Frequency Response listed in the previous section. It also provides an indication of the relative value of these characteristics with respect to their contribution to reliability. Finally, it includes some examples of the described responses.

Inertial Response is provided from the stored energy in the rotating mass of the turbine-generators and synchronous motors on the interconnection. It limits the rate of change of frequency until sufficient Frequency Response can be supplied to arrest the change in frequency. Its reliability value increases as the time delay associated with the delivery of other Frequency Response on the interconnection increases. If those time delays are minimal, then the value of inertial response is low. If all time delays associated with the Frequency Response could be eliminated, then inertial response would have little value.

The reliability value of Inertial Response is the greatest on small interconnections because the size of the Disturbance events is larger relative to the inertia of the interconnection. Electronic controls have been developed to provide synthetic inertial response from the stored energy in asynchronous generators to supplement the natural inertial response. Some Type III & IV Wind Turbines have this capability. In addition, electronically controlled SCRs have been developed that can store energy in the electrical system and release this stored energy to supply synthetic inertial response when required.

Immediate Response is provided by load damping and because the time delays associated with its delivery are very short (related to the speed of electrical signal in the electrical system); load damping requires very little inertial response to limit arrested frequency effectively. Synthetic immediate response can also be supplied from loads because in many cases, there is no mass flow time delay associated with the load process providing the power and energy reduction. Therefore, loads can provide an immediate response with a higher reliability value than generators with time delays required by the physics of the turbine-generator.

Governor response has time delays associated with its delivery. Governor response provided with shorter time delays has a higher reliability value because those shorter time delays require less inertial response to arrest frequency. Governor response is provided by the turbine-generators on the interconnection. Time delays associated with governor response vary depending on the type of turbine-generator providing the response.

The longest time delays are usually associated with high head hydro turbine-generators that require long times from the governor action until the additional mass flow through the turbine. These units may also have the longest delivery time associated with the full delivery of response because of the timing designed into the governor response.[5]

Intermediate time delays are usually associated with steam turbine-generators. The response begins when the steam control valves are adjusted and the steam mass flows from the valves to the first high pressure turbine blades. The delivery times associated with the full delivery of response may require the steam to flow through high, intermediate and low pressure turbines including reheat flows before full power is delivered. These times are shorter than those of the hydro turbine-generators in general, but not as fast as the times associated with gas turbines.[6]

Gas turbines typically have the shortest time delays, because control is provided by injecting more or less fuel into the turbine combustor and adjusting the air control dampers. These control changes can be initiated rapidly and the mass flow has the shortest path to the turbine

[5] Interconnected Power System Response to Generation Governing: Present Practice and Outstanding Concerns – Final Report, IEEE, May 2007, pp. 1-6 – 1-9.

[6] Interconnected Power System Response to Generation Governing: Present Practice and Outstanding Concerns – Final Report, IEEE, May 2007, pp. 1-4 – 1-6.

blades. There may be timing limitations related to the rate of change in output of the gas turbine-generator to maintain flame stability in some cases slowing the rate of change.[7]

Synthetic Governor Response can be supplied by certain loads and storage systems. The immediacy of the response is normally limited only by the electronic controls used to activate the desired response. Synthetic response, when it can be supplied immediately without significant time delay, has a higher reliability value because it requires less inertial response to achieve smaller arrested frequency deviations.

Proportional Response indicates that the response provided is proportional in magnitude to the frequency error. Response deadbands cause a non-proportional response and reduce the value of the response with respect to reliability. Contrary to general consensus, deadbands do not reduce the amount of Frequency Response that must be provided, they only transfer the responsibility for providing that Frequency Response from one source on the interconnection to another. For a given response, the response with the smaller deadband has the greater reliability value. Therefore, deadbands should be set to the smallest value that supports overall reliable operation including the reliable operation of the generator.

Electronic controls have also been developed to provide synthetic governor response. When these controls are applied to certain loads or stored energy systems, they can be programmed to provide synthetic governor response similar to the proportional response of a turbine-generator governor. Governor response in generators is limited to a small percentage of the output of the generating unit, while synthetic governor response could be applied to much larger percentages of loads or storage devices providing such response.

Load damping provides a proportional response.

Continuous Response is response that has no discontinuous (step) changes in the frequency versus response curve. Step changes (Non-continuous Response) in the Governor Response curve can lead to frequency instabilities at frequencies near the changes. The ERCOT Interconnection observed this and has since prohibited the use of governor response characteristics incorporating step responses.

Step responses also occur with the implementation of load interruption using under-frequency or over-frequency relays.

Bi-directional Response is response that occurs in both directions, when the frequency is increasing and when the frequency is decreasing. A uni-directional response is a response that only occurs once when frequency is decreasing or when frequency is increasing.

Inertial response, governor response and load damping are all bi-directional responses. Certain loads are capable of providing proportional bi-directional response while others are only capable of providing non-proportional bi-directional response.

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[7] Interconnected Power System Response to Generation Governing: Present Practice and Outstanding Concerns – Final Report, IEEE, May 2007, pp. 1-16 – 1-19.

The ERCOT Load Resource program is a uni-directional response program. Loads are only tripped when frequency declines below a given set-point. When frequency is restored above that set-point, the loads must be manually reconnected. As a consequence, the Frequency Response only occurs once with declining frequency and does not oppose the increase in frequency after the initial decline. If there should be a frequency oscillation, the uni-directional response will not contribute to the opposition of a second frequency decline across the set-point during an oscillation event. Once a uni-directional response has occurred, it is unavailable for a second decline before reset.

Step or proportional responses implemented bi-directionally can lead to frequency instability when there is less continuous frequency response than the magnitude of the change in continuous response between the trip and reset frequencies in step, or the proportional response rate of change is greater than the underlying continuous response. A step bi-directional response will have the load reconnected as frequency recovers from the event thus opposing the increase in frequency during recovery, and also resetting the load response for the next frequency decline automatically. Bi-directional response obviously has a greater reliability value than uni-directional response.

Sustained Response is provided at its full value until frequency is restored to its scheduled value. On today's interconnections, few frequency responses are fully sustained until frequency has been restored to its scheduled value. On steam based turbine-generators, the steam pressure may drop after a time as the result of the additional steam flow from governor action. However, in general this has not been a problem because most responses are incomplete at the time that frequency has been initially arrested and the additional response has generally been sufficient to make up for more than the these unpreventable reductions in response. However, the intentional withdrawal of response before frequency has been restored to schedule can cause a decline in frequency beyond that which would be otherwise expected. This intentional withdrawal of response is highly detrimental to reliability. Therefore, it can be concluded in general that sustained response has a higher reliability value than un-sustained response.

On an interconnection, the withdrawal of response due to the loss of steam pressure on the steam units may be offset by the slower response of hydro turbine-generators. In these cases, the reliability of the combined response provides a greater reliability value than the individual response of each type. The steam turbine-generators provide a fast response that may be reduced, while the hydro turbine-generators provide a slower response, contributing less to the arresting response, offsetting any reduction by the steam turbine-generators to assure a sustained response.

Sustained Response must also be considered for any resource that has a limited duration associated with its response. The amount of stored energy available from a resource may limit its ability to sustain response for a duration of time necessary to support reliability.

Frequency Response Cost Factors

In every system of exchange there are two sides; the supply side and the demand side. The supply side provides the services used by the demand side. In the case of Frequency Response,

the supply side includes all providers of Frequency Response and the demand side includes all participants that create the need for Frequency Response.

Frequency Response Costs – Supply Side

There are a number of factors that affect the cost of providing Frequency Response from resources. Since there is a cost associated with those factors, some method of appropriate compensation could be made available to those resources providing Frequency Response. Without compensation, providers of Frequency Response will be put in the position of incurring additional cost that can be avoided only by reducing or eliminating the response they provide. These costs are incurred independently of whether provided for in a formal Regional Transmission Organization/Independent System Operator (RTO/ISO) market or in a traditional BA subject to the FERC pro-forma tariffs.

It is the responsibility of the BA or the RTO/ISO to acquire the necessary amount of Frequency Response to support reliability in the most cost effective manner. This function is performed best when the suppliers are evaluated based on the value of the Frequency Response they provide and compensated appropriately for that Frequency Response. Suppliers provide Frequency Response when they are assured that they will receive fair compensation. Before considering how to perform this evaluation and compensation, the costs associated with providing Frequency Response should be understood and evaluated with respect to the level of reliability they offer.

Some cost factors that have been identified for providing Frequency Response include:

1. **Capacity Opportunity Cost** – the costs, including opportunity costs, associated with reserving capacity to provide Frequency Response. These costs are usually associated with the alternative use of the same capacity to provide energy or other ancillary services. There may also be capacity opportunity costs associated with the loss in average capacity by a load providing Frequency Response.
2. **Fuel Cost** – The cost of fuel used to provide the Frequency Response. The costs for fuel to provide Frequency Response can result in energy costs significantly different from the system marginal energy cost, both higher and lower. This is the case when Frequency Response is provided by resources that are not at the system marginal cost.
3. **Energy Efficiency Penalty Costs** – the costs associated with the loss in efficiency when the resource is operated in a mode that supports the delivery of Frequency Response. This cost is usually in the form of additional fuel use to provide the same amount of energy. An example is the difference between operating a steam turbine in valve control mode with an active governor and sliding pressure mode with valves wide open and no active governor control except for over-speed. This cost is incurred for all of the energy provided by the resource, not just the energy provided for Frequency Response. There may be additional energy costs associated with a load providing Frequency Response from loss in efficiency of their process when load is reduced.
4. **Capacity Efficiency Penalty Costs** – the costs associated with any reduction in capacity resulting from the loss of capacity associated with the loss in energy efficiency. When efficiency is lost, capacity may be lost at the same time because of limitations in the amount of input energy that can be provided to the resource.

5. **Maintenance Costs** – the operation of the resource in a manner necessary to provide Frequency Response may result in increases in the maintenance costs associated with the resource.
6. **Emissions Costs** – the additional costs incurred to manage any additional emissions that result when the resource is providing Frequency Response or stands ready to provide Frequency Response.

A good contract for the acquisition of Frequency Response from a resource will provide appropriate compensation to the resource for all of the costs the resource incurs to provide Frequency Response. It will also provide a method to evaluate the least cost mix of resources necessary to provide the minimum required Frequency Response for maintaining reliability. Finally, it will provide the least complex method of evaluation considering the complexity and efficiency of the acquisition process.

Frequency Response Costs – Demand Side

Not only are there costs associated with acquiring Frequency Response from the supplying resources, there are costs associated with the amount of Frequency Response that must be acquired and influenced by those participants that create the need for Frequency Response. If the costs of acquiring Frequency Response from the supply resources can be assigned to those parties that create the need for Frequency Response, there is the promise that the amount of Frequency Response required to maintain reliability can be minimized. The considerations are the same as those that are driving the development of "real time pricing" and "dynamic pricing". If the costs are passed on to those contributing to the need for Frequency Response, incentives are created to reduce the need for Frequency Response making interconnection operations less expensive and more reliable. The problem is to balance both cost and complexity against reliability on both the supply side and the demand side.

Rationale by Requirement

Requirement 1

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 Balancing Authority that is not a member of a FRSG to maintain Interconnection Frequency Response equal to or more negative than the Interconnection Frequency Response Obligation.

Background and Rationale

R1 is intended to meet the following primary objectives:

- Determine whether a Balancing Authority (BA) has sufficient Frequency Response for reliable operations.
- Provide the feeder information needed to calculate CPS limits and Frequency Bias Settings.

Primary Objective

With regard to the first objective, FRS Form 1 and the process in Attachment A provide the method for determining the Interconnections' necessary amount of Frequency Response and allocating it to the Balancing Authorities. The field trial for BAL-003-1 is testing an allocation methodology based on the amount of load and generation in the BA. This is to accommodate the wide spectrum of BAs from generation-only all the way to load-only.

Frequency Response Sharing Groups (FRSGs)

This standard proposes an entity called FRSG, which is defined as:

> *A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the sum of the Frequency Response Obligations of its members.*

This standard allows Balancing Authorities to cooperatively form FRSGs as a means to jointly meet the FRS. There is no obligation to form or be a part of FRSGs. The members of the FRSG would determine how to allocate sanctions among its members. This standard does not mandate the formation of FRSGs, but allows them as a means to meet one of FERC's Order No. 693 directives.

FRSG performance may be calculated one of two ways:

- Calculate a group NI_A and measure the group response to all events in the reporting year on a single FRS Form 1, or
- Jointly submit the individual BAs' Form 1s, with a summary spreadsheet that sums each participant's individual event performance.

Frequency Response Obligation and Calculation

The basic Frequency Response Obligation is based on annual load and generation data reported in FERC Form 714 (where applicable, see below for non-jurisdictional entities) for the previous full calendar year. The basic allocation formula used by NERC is:

$$\mathrm{FRO_{BA}} = \mathrm{FRO_{Int}} \times \frac{\text{Annual Gen}_{\mathrm{BA}} + \text{Annual Load}_{\mathrm{BA}}}{\text{Annual Gen}_{\mathrm{Int}} + \text{Annual Load}_{\mathrm{Int}}}$$

Where:

- Annual $\mathrm{Gen_{BA}}$ is the annual "Net Generation (MWh)", FERC Form 714, line 13, column c of Part II - Schedule 3.
- Annual $\mathrm{Load_{BA}}$ is the annual "Net Energy for Load (MWh)", FERC Form 714, line 13, column e of Part II - Schedule 3.
- Annual $\mathrm{Gen_{Int}}$ is the sum of all Annual $\mathrm{Gen_{BA}}$ values reported in that interconnection.
- Annual $\mathrm{Load_{Int}}$ is the sum of all Annual $\mathrm{Load_{BA}}$ values reported in that interconnection.

Balancing Authorities that are not FERC jurisdictional should use the Form 714 Instructions to assemble and submit equivalent data. Until the BAL-003-1 process outlined in Attachment 1 is implemented, Balancing Authorities can approximate their FRO by multiplying their Interconnection's FRO by their share of Interconnection Bias. The data used for this calculation should be for the most recently filed Form 714. As an example, a report to NERC in January 2013 would use the Form 714 data filed in 2012, which utilized data from 2011.

Balancing Authorities that merge or that transfer load or generation need to notify the ERO of the change in footprint and corresponding changes in allocation such that the net obligation for the Interconnection remains the same and so that CPS limits can be adjusted.

Attachment A proposes the following Interconnection event criteria as a basis to determine an Interconnection's Frequency Response Obligation:

- Largest category C loss-of-resource (N-2) event.
- Largest total generating plant with common voltage switchyard.
- Largest loss of generation in the interconnection in the last 10 years.

With regard to the second objective above (determining Frequency Bias Settings and CPS limits), Balancing Authorities have been asked to perform annual reviews of their Frequency Bias Settings by measuring their Frequency Response, dating back to Policy 1. This obligation was carried forward into BAL-003-01.b. While the associated training document provided useful information, it left many of the details to the judgment of the person doing the analysis. The FRS Form 1 and FRS Form 2 provide a consistent, objective process for calculating Frequency Response to develop an annual measure, the FRM.

The FRM will be computed from Single Event Frequency Response Data (SEFRD), defined as: "the data from an individual event from a Balancing Authority that is used to calculate its Frequency Response, expressed in MW/0.1Hz". The SEFRD for a typical Balancing Authority in an Interconnection with more than one Balancing Authority is basically the change of its net actual interchange on its tie lines with its adjacent Balancing Authorities divided by the change in interconnection frequency. (Some Balancing Authorities may choose to apply corrections to their net actual interchange values to account for factors such as nonconforming loads. FRS Form 1 shows the types of adjustments that are allowed.)

A standardized sampling interval of approximately 20 to 52 seconds will be used in the computation of SEFRD values. Microsoft Excel® spreadsheet interfaces for EMS scan rates of 2 through 6 seconds are provided to support the computation.

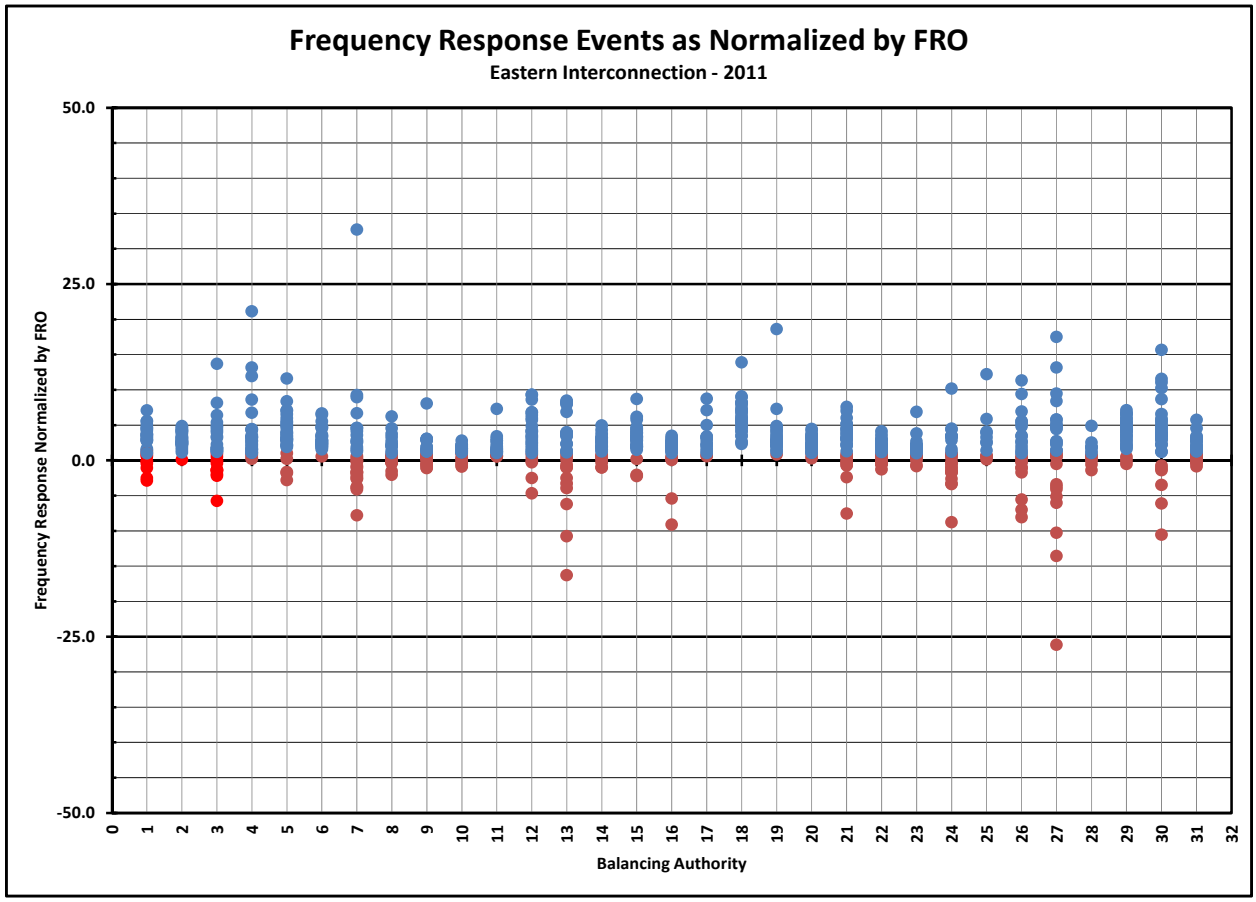
Single Event Frequency Response Data[8]

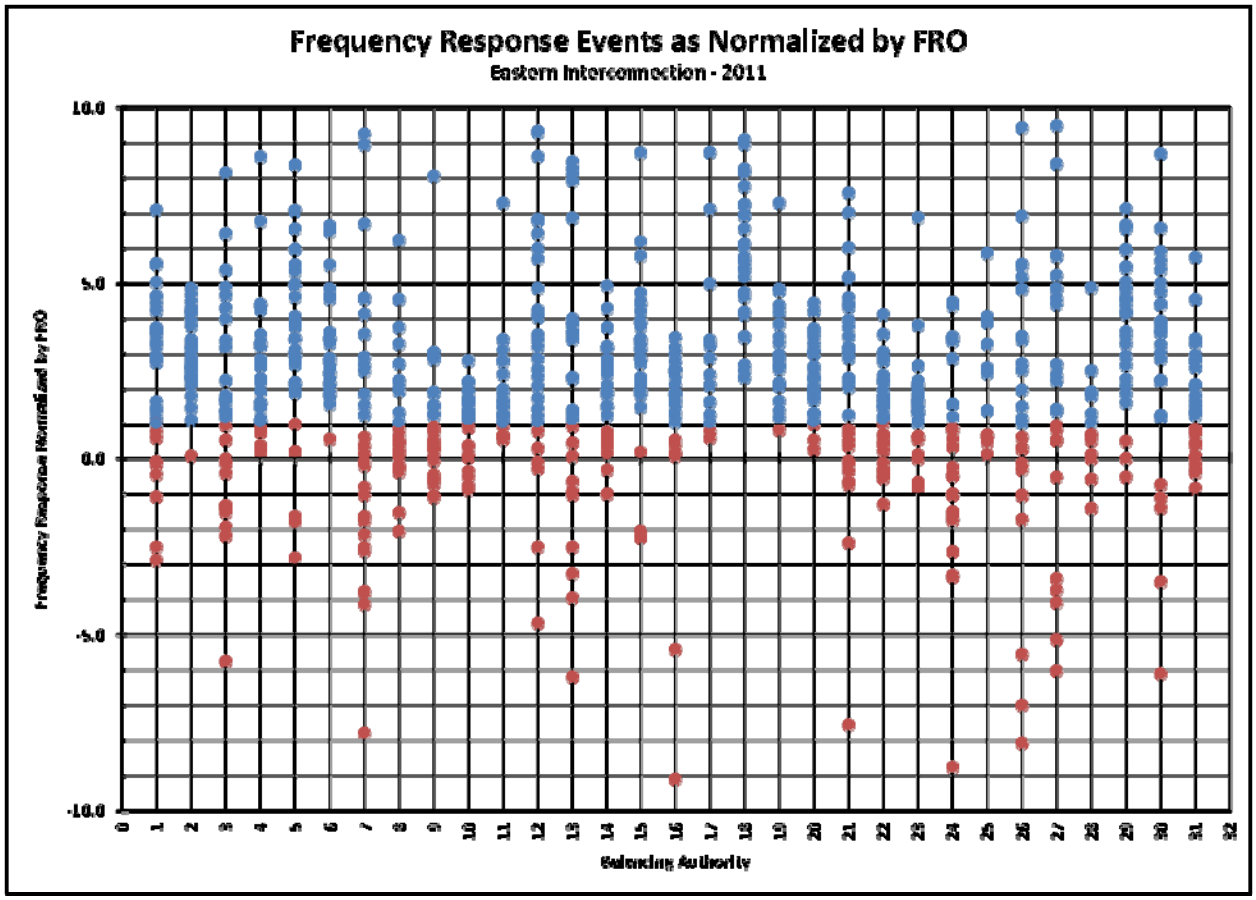
The use of a "single event measure" was considered early in the development of the FRS for compliance because a single event measure could be enforced for each event on the interconnection making compliance enforcement a simpler process. The variability of the measurement of Frequency Response for an individual BA for an individual Disturbance event was evaluated to determine its suitability for use as a compliance measure. The individual Disturbance events were normalized and plotted for each BA on the Eastern and Western Interconnections. This data was plotted with a dot representing each event. Events with a measured Frequency Response above the FRO were shown as blue dots and events with a measured Frequency Response below the FRO were shown as red dots. In order to show the full variability of the results the plots have been provided with two scales, a large scale to show all of the events and small scale to show the events closer to the FRO or a value of 1.0. This data is presented on four charts titled Frequency Response Events as Normalized by FRO.

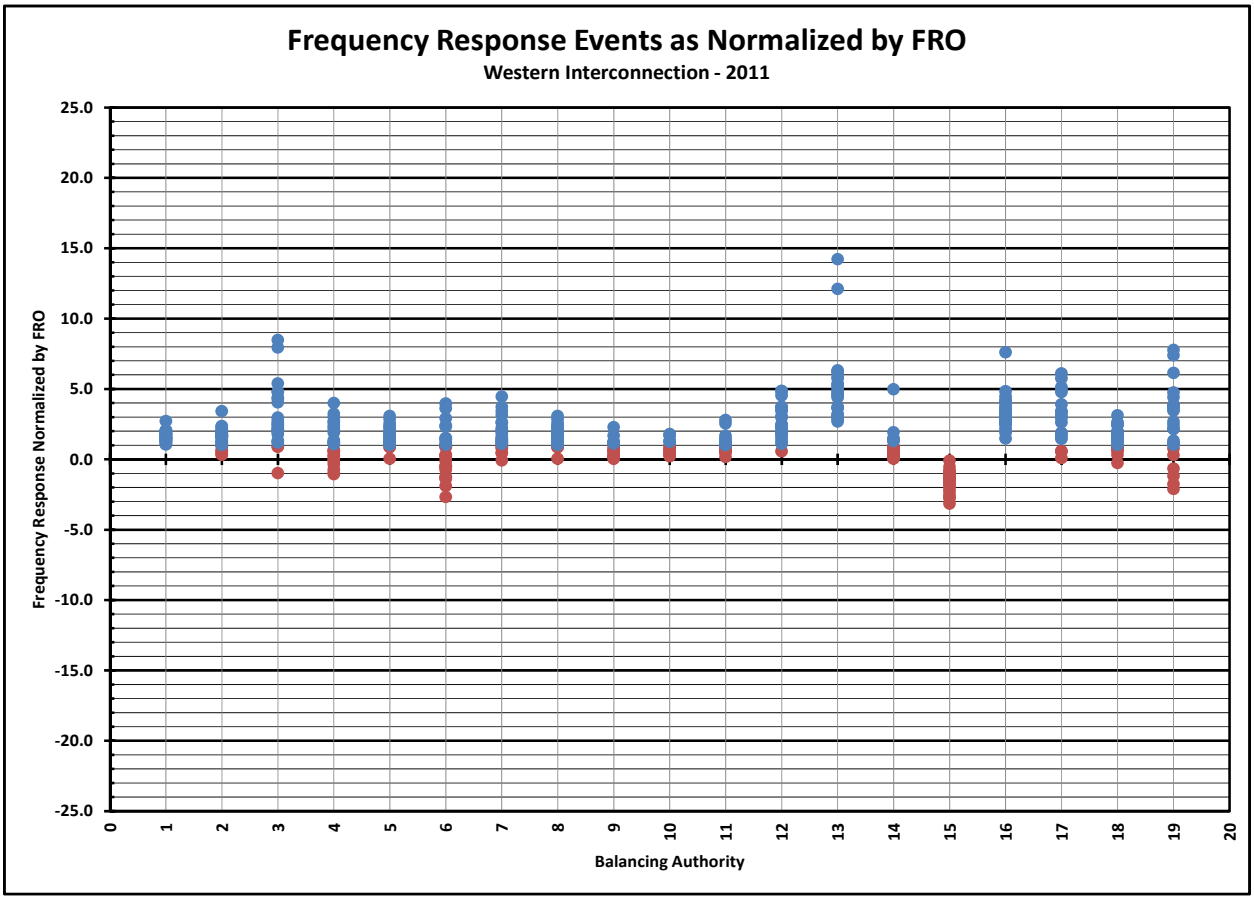
Analysis of this data indicates a single event based compliance measure is unsuitable for compliance evaluation when the data has the large degree of variability shown in these charts. Based on the field trial data provided, only 3 out of 19 BAs on the Western Interconnection would be compliant for all events with a standard based on a single event measure. Only 1 out of 31 BAs on the Eastern Interconnection would be compliant for all events with a standard based on a single event measure. The general consensus of the industry is that there is not a reliability issue with insufficient Frequency Response on any of the North American Interconnections at this time. Therefore, it is unreasonable to even consider a standard that would indicate over 90% of the BAs in North American to be non-compliant with respect to maintaining sufficient Frequency Response to maintain adequate reliability.

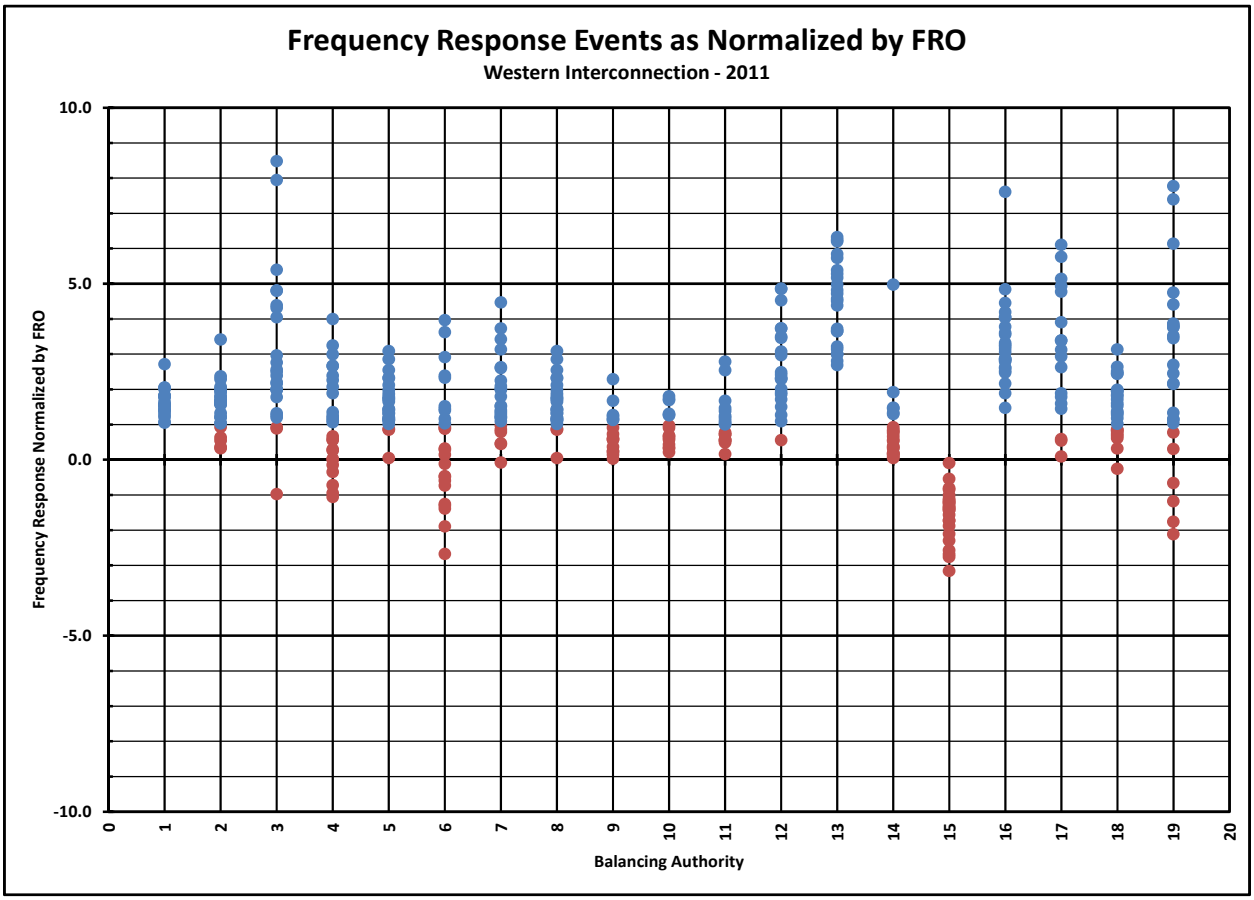
In an attempt to balance the workload of Balancing Authorities with the need for accuracy in the FRM, the standard will require at least 20 samples selected during the course of the year to compute the FRM. Research conducted by the FRSDT indicated that a Balancing Authority's FRM will converge to a reasonably stable value with at least 20 samples.

[8] Single Event Analysis based on results of Frequency Response Standard Field Trial Analysis, September 17, 2012.


Frequency Response Events as Normalized by FRO
Eastern Interconnection - 2011
Frequency Response Normalized by FRO
50.0
25.0
0.0
-25.0
-50.0
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31 32
Balancing Authority


Frequency Response Events as Normalized by FRO
Eastern Interconnection - 2011
10.0
5.0
0.0
-5.0
-10.0


Frequency Response Events as Normalized by FRO
Western Interconnection - 2011
Frequency Response Normalized by FRO
25.0
20.0
15.0
10.0
5.0
0.0
-5.0
-10.0
-15.0
-20.0
-25.0
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20
Balancing Authority


Frequency Response Events as Normalized by FRO
Western Interconnection - 2011
Frequency Response Normalized by FRO
10.0
5.0
0.0
-5.0
-10.0
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20
Balancing Authority

Sample Size
In order to support field trial evaluations of sample size, sampling intervals, and aggregation techniques, the FRSDT will be retrieving scan rate data from the Balancing Authorities for each SEFRD. Additional frequency events may also be requested for research purposes, though they will not be included in the FRM computation.

FERC Order No. 693 directed the ERO (at P 375) to define the number of Frequency Response surveys that were conducted each year and to define a necessary amount of Frequency Response. R1 addresses both of these directives:

- There is a single annual survey of at least 20 events each year.
- The FRM calculated on FRS Form 1 is compared by the ERO against the FRO determined 12 months earlier (when the last FRS Form 1 was submitted) to verify the Balancing Authority provided its share of Interconnection Frequency Response.

Median as the Standard's Measure of Balancing Authority Performance
The FRSDT evaluated different approaches for "averaging" individual event observations to compute a technically sound estimate of Frequency Response Measure. The MW contribution for a single BA in a multi-BA Interconnection is small compared to the minute to minute changes in load, interchange and generation. For example, a 3000 MW BA in the Eastern Interconnection may only be called on to contribute 10MW for the loss of a 1000MW. The 10 MW of governor and load response may easily be masked as a coincident change in load.

In general, statisticians use the median as the best measure of central tendency when a population has outliers. Two independent reviews by the FRSDT has shown the Median to be less influenced by noise in the measurement process and the team has chosen the median as the initial metric for calculating the BAs' Frequency Response Measure.

The FRSDT performed extensive empirical studies and engaged in lively discussions in an attempt to determine the best aggregation technique for a sample set size of at least 20 events. Mean, median, and linear regression techniques were used on a trial basis with the data that was available during the early phases of the effort.

A key characteristic of the "aggregation challenge" is related to the use of actual net interchange data for measuring frequency response. The tie line flow measurements are varying continuously due to other operational phenomena occurring concurrently with the provision of frequency response. (*See* Appendix 1 for details.) All samples have "noise" in them, as most operational personnel who have computed the frequency response of their BA can attest. What has also become apparent to the FRSDT is that while the majority of the frequency response samples have similar levels of noise in them, a few of the samples may have much larger errors in them than the others that result in unrepresentative results. And with the sample set size of interest, it is common to have unrepresentative errors in these few samples to be very large and asymmetric. For example, one BA's subject matter expert observed recently that 4 out of 31 samples had a much larger error contribution than the other 27 samples, and that 3 out of 4 of the very high error samples grossly underestimated the frequency response. The median value demonstrated greater resiliency to this data quality problem than the mean with this data set. (The median has also demonstrated superiority to

linear regression in the presence of these described data quality problems in other analyses conducted by the FRSDT, but the linear regression showed better performance than the mean.)

The above can be demonstrated with a relatively simple example. Let's assume that a Balancing Authority's true frequency response has an average value of -200 MW/ .1 Hz. Let's also assume that this Balancing Authority installed "special" perfect metering on key loads and generators, so that we could know the true frequency response of each sample. And then we will compare them with that measured by typical tie line flow metering, with the kind of noise and error that occurs commonly and "not so commonly". Let's start with the following 4 samples having a common level of noise, with MW/ .1 Hz as the unit of measurement.

Perfect measurement	Noise	Samples from tie lines
-190	-30	-220
-210	-20	-230
-220	10	-210
-180	20	-160
-200	Mean	-205
-200	Median	-215

Now let's add a fifth sample, which is highly contaminated with noise and error that grossly underestimates frequency response.

Perfect measurement	Noise	Samples from tie lines
-190	-30	-220
-210	-20	-230
-220	10	-210
-180	20	-160
-200	250	+50
-200	Mean	-154
-200	Median	-210

It is clear from the above simplistic example that the mean drops by about 25% while the median is affected minimally by the single highly contaminated value.

Based on the analyses performed thus far, the FRSDT believes that the median's superior resiliency to this type of data quality problem makes it the best aggregation technique at this time. However, the FRSDT sees merit and promise in future research with sample filtering combined with a technique such as linear regression.

When compared with the mean, linear regression shows superior performance with respect to the elimination of noise because the measured data is weighted by the size of the frequency change associated with the event. Since the noise is independent from frequency change, the greater weighting on larger events provides a superior technique for reducing the effect of noise on the results.

However, linear regression does not provide a better method when dealing with a few samples with large magnitudes of noise and unrepresentative error. There are only two alternatives to improve over the use of median when dealing with these larger unrepresentative errors:

1. Increase the sample size, or
2. Actively eliminate outliers due to unrepresentative error.

Unfortunately, the first alternative, increasing the sample size is not available because significantly more sample events are not available within the measurement time period of one year. Linear regression techniques are being investigated that have an active outlier elimination algorithm that would eliminate data that lie outside ranges of the 96th percentile and 99th percentile, for example.

Still, the use of linear regression has value in the context of this standard. The NERC Resources Subcommittee will use linear regression to evaluate Interconnection frequency response, particularly to evaluate trends, seasonal impacts, time of day influences, etc. The Good Practices and Tools section of this document outlines how a BA can use linear regression to develop a predictive tool for its operators.

Additional discussion on this topic is contained in "Appendix 1 – Data Quality Concerns Related to the Use of Actual Net Interchange Value" of this document.

The NERC Frequency Response Initiative Report addressed the relative merits of using the median versus linear regression for aggregating single event frequency response samples into a frequency response measurement score for compliance evaluation. This report provided 11 evaluation criteria as a basis for recommending the use of linear regression instead of the median for the frequency response measurement aggregation technique. The FRSDT made its own assessment on the basis of these evaluation criteria on September 20, 2012, but concluded that the median would be the best aggregation technique to use initially when the relative importance of each criterion was considered. A brief summary of the FRSDT majority consensus on the basis of each evaluation criterion is provided below.

- Provides two dimensional measurement – The FRSDT agrees that the two dimensional concept is a useful way to perceive frequency response characteristics, and that it may be useful for potential future modeling activities. Better data quality would increase support for such future efforts, and the use of the median for initial compliance evaluations within BAL-003-1 should not hinder any such effort. The FRSDT perceived this as a mild advantage for linear regression.
- Represents nonlinear characteristics – With considerations similar to those applied to the previous criterion, the FRSDT perceived this as a mild advantage for linear regression.
- Provides a single best estimator – The FRSDT gave minimal importance to the characteristic of the median averaging the middle values when used with an even number of samples.
- Is part of a linear system - With considerations similar to those applied to the first two criteria, the FRSDT perceived this as a mild advantage for linear regression (particularly in the modeling area.)
- Represents bimodal distributions – The FRSDT gave minimal weight of this criterion, as a change in Balancing Authority footprint does not seem to be addressed adequately by any aggregation technique.
- Quality statistics available – The FRSDT perceived this as a mild advantage for linear regression in that the statistics would be coupled directly to the compliance evaluation. The FRSDT also included this criterion as part of the modeling advantages cited above.

The FRSDT supports collecting data and performing quality statistical analysis. If it is determined that the use of the median, as opposed to a mean or linear regression aggregation, is yielding undesirable consequences, the FRSDT recommends that other aggregation techniques be re-evaluated at that time.

- Reducing influence of noise - This is the dominant concern of the FRSDT, and it perceives the median to have a major advantage over linear regression in addressing noise in the change in actual net interchange calculation. The FRSDT bases this judgment on: prior FRSDT studies that have shown that the median produces more stable results; the data used in the NERC Frequency Response Initiative document exhibits large quantities of noise; prior efforts of FRSDT members in performing frequency response sampling for their own Balancing Authorities over many years; and similar observations of noise in the CERTS frequency Monitoring Application. The FRSDT has serious concerns that the influence of noise has a greater tendency to yield a "false positive" compliance violation with linear regression than with the median. Also, limited studies performed by the FRSDT indicates the possibility that the resultant frequency response measure would yield more measurement variation across years with linear regression versus the median while the actual Balancing Authority performance remains unchanged.
- Reducing the influence of outliers – This is related to the previous criterion. The FRSDT recognizes four main sources of noise: concurrent operating phenomena (described elsewhere in this document), transient tie line flows for nearby contingencies, data acquisition time skew in tie line data measurements, and time skew and data compression issues in archiving techniques and tools such as PI. Some outliers may be caused in part by true variation in the actual frequency response, and it is desirable to include those in the frequency response measure. The FRSDT supports efforts in the near future to distinguish between outliers caused by noise versus true frequency response, and progress in this area may make it feasible and desirable to replace the median with linear regression, or some other validated technique. The FRSDT does note that this is a substantial undertaking, and it would require substantial input from a sufficient number of experts to help distinguish noise from true frequency response.
- Easy to calculate – The FRSDT perceives this to be a minor to moderate advantage for the median. However, more complex (but reasonably so) techniques would receive more support if clear progress can be made in noise elimination.
- Familiar indicator – The FRSDT perceives this to be a minor to moderate advantage for the median. However, more complex (but reasonably so) techniques would receive more support if clear progress can be made as a result of noise elimination.
- Currently used as a measure in BAL-003 – The present standard refers to an average and does not provide specific guidance on the computation of that average, but the FRSDT puts minimal weight on this evaluation criterion.

In summary, the FRSDT perceives an approximate balance between the modeling advantage for linear regression and the simplicity advantage of the median. However, the clear determinant in endorsing the use of the median is the data quality issue related to concurrent operational phenomena, transient tie line flows, and data acquisition and archiving limitations.

FERC Order No. 693 also directed the Standard (at P 375) to identify methods for Balancing Authorities to obtain Frequency Response. Requirement R1 allows Balancing Authorities to participate in Frequency Response Sharing Groups (FRSGs) to provide or obtain Frequency Response. These may be the same FRSGs that cooperate for BAL-002-0 or may be FRSGs that form for the purposes of BAL-003-1.

If BAs participate as an FRSG for BAL-003-1, compliance is based on the sum of the participants' performance.

Two other ways that BAs could obtain Frequency Response are through Supplemental Service or Overlap Regulation Service:

- No special action is needed if a BA provides or receives supplemental regulation. If the regulation occurs via Pseudo Tie, the transfer occurs automatically as part of Net Actual Interchange (NIA) and in response to information transferred from recipient to provider.
- If a BA provides overlap regulation, its FRS Form 1 will include the Frequency Bias setting as well as peak load and generation of the combined Balancing Authority Areas. The FRM event data will be calculated on the sum of the provider's and recipient's performance.

In the Violation Severity Levels for Requirement R1, the impact of a BA not having enough frequency response depends on two factors:

- Does the Interconnection have sufficient response?
- How short is the BA in providing its FRO?

The VSL takes these factors into account. While the VSLs look different than some other standards, an explanation would be helpful.

VSLs are a starting point for the enforcement process. The combination of the VSL and VRF is intended to measure a violation's impact on reliability and thus levy an appropriate sanction. Frequency Response is an interconnection-wide resource. The proposed VSLs are intended to put multi-BA Interconnections on the same plane as single-BA Interconnections.

Consider a small BA whose performance is 70% of its FRO. If all other BAs in the Interconnection are compliant, the small BA's performance has negligible impact on reliability, yet would be sanctioned at the same level as a BA who was responsible for its entire Interconnection. It is not rational to sanction this BA the same as a single BA Interconnection that had insufficient Frequency Response, because this would treat multi-BA Interconnections more harshly than single BA Interconnections on a significant scale.

The "Lower" and "Medium" VSLs say that the Interconnection has sufficient Frequency Response but individual BAs are deficient by small or larger amounts respectively. The High and Severe VSLs say the Interconnection does not meet the FRO and assesses sanctions based on whether the BA is deficient by a small or larger amount respectively.

Requirement 2

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.

Background and Rationale

Attachment A of the Standard discusses the process the ERO will follow to validate the BA's FRS Form 1 data and publish the official Frequency Bias Settings. Historically, it has taken multiple rounds of validation and outreach to confirm each BA's data due to transcription errors, misunderstanding of instructions, and other issues. While BAs historically submit Bias Setting data by January 1, it often takes one or more months to complete the process.

The target is to have BAs submit their data by January 10. The BAs are given 30 days to assemble their data since the BAs are dependent on the ERO to provide them with FRS Form 1, and there may be process delays in distributing the forms since they rely on identification of frequency events through November 30 of the preceding year.

Frequency Bias Settings generally change little from year to year. Given the fact that BAs can encounter staffing or EMS change issues coincident with the date the ERO sets for new Frequency Bias Setting implementation, the standard provides a 24 hour window on each side of the target date.

To recap the annual process:

1. The ERO posts the official list of frequency events to be used for this Standard in early December. The FRS Form 1 for each Interconnection will be posted shortly thereafter.

2. The Balancing Authority submits its revised annual Frequency Bias Setting value to NERC by January 10.

3. The ERO and the Resources Subcommittee validate Frequency Bias Setting values, perform error checking, and calculate, validate, and update CPS2 L10 values. This data collection and validation process can take as long as two months.

4. Once the L10 and Frequency Bias Setting values are validated, The ERO posts the values for the upcoming year and also informs the Balancing Authorities of the date on which to implement revised Frequency Bias Setting values. Implementation typically would be on or about March 1st of each year.

BAL-003-0.1b standard requires a minimum Frequency Bias Setting equal in absolute value to one percent of the Balancing Authority's estimated yearly peak demand (or maximum generation level if native load is not served). For most Balancing Authorities this calculated amount of Frequency Bias is significantly greater in absolute value than their actual Frequency Response characteristic (which represents an over-bias condition) resulting in over-control

since a larger magnitude response is realized. This is especially true in the Eastern Interconnection where this condition requires excessive secondary frequency control response which degrades overall system performance and increases operating cost as compared to requiring an appropriate balance of primary and secondary frequency control response.

Balancing Authorities were given a minimum Frequency Bias Setting obligation because there had never been a mandatory Frequency Response Obligation. This historic "one percent of peak per 0.1Hz" obligation, dating back to NERC's predecessor, NAPSIC, was intended to ensure all BAs provide some support to Interconnection frequency.

The ideal system control state exists when the Frequency Bias Setting of the Balancing Authority exactly matches the actual Frequency Response characteristic of the Balancing Authority. If this is not achievable, over-bias is significantly better from a control perspective than under-bias with the caveat that Frequency Bias is set relatively close in magnitude to the Balancing Authority actual Frequency Response characteristic. Setting the Frequency Bias to better approximate the Balancing Authority natural Frequency Response characteristic will improve the quality and accuracy of ACE control, CPS & DCS and general AGC System control response. This is the technical basis for recommending an adjustment to the long standing "1% of peak/0.1Hz" Frequency Bias Setting. The Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard is intended to bring the Balancing Authorities' Frequency Bias Setting closer to their natural Frequency Response. Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard balances the following objectives:

- Bring the Frequency Bias Setting and Frequency Response closer together.
- Allow time to analyze impact on other Standards (CPS, BAAL and to a lesser extent DCS) by adjustments in the minimum Frequency Bias Setting, by accommodating only minor adjustments.
- Do not allow the Frequency Bias Setting minimum to drop below natural Frequency Response, because under-biasing could affect an Interconnection adversely.

Additional flexibility has been added to the Frequency Bias Setting based on the actual Frequency Response (FRM) by allowing the Frequency Bias Setting to have a value in the range from 100% of FRM to 125% of FRM. This change has been included for the following reasons:

- When the new standardized measurement method is applied to BAs with a Frequency Response close to the interconnection minimum response, the requirement to use FRM is as likely to result in a Frequency Bias Setting below the actual response as it is to result in a response above the actual response. From a reliability perspective, it is

always better to have a Frequency Bias Setting slightly above the actual Frequency Response.

- As with single BA interconnections, the tuning of the control system may require that the BA implement a Frequency Response Setting slightly greater in absolute terms than its actual Frequency Response to get the best performance.
- The new standardized measurement method for determining FRM in some cases results in a measured Frequency Response significantly lower than the previous methods used by some BAs. It is desirable to not require significant change in the Frequency Bias Setting for these BAs that experience a reduction in their measured Frequency Response.

Requirement 3

R3. Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection, is not receiving Overlap Regulation Service and utilizing a variable Frequency Bias Setting shall maintain a Frequency Bias Setting that is:

- *Less than zero at all times, and*
- *Equal to or more negative than its Frequency Response Obligation when the Frequency varies from 60 Hz by more that +/- 0.036 Hz.*

Background and Rationale

In multi-Balancing Authority interconnections, the Frequency Bias Setting should be coordinated among all BAs on the interconnection. When there is a minimum Frequency Bias Setting requirement, it should apply for all BAs. However, BAs using a variable Frequency Bias Setting may have non-linearity in their actual response for a number of reasons including the dead-bands implemented on their generator governors. The measurement to ensure that these BAs are conforming to the interconnection minimum is adjusted to remove the dead-band range from the calculated average Frequency Bias Setting actually used. For BAs using variable bias, FRS Form 1 has a data entry location for the previous year's average monthly Bias. The Balancing Authority and the ERO can compare this value to the previous year's Frequency Bias Setting minimum to ensure R3 has been met.

On single BA interconnections, there is no need to coordinate the Frequency Bias Setting with other BAs. This eliminates the need to maintain a minimum Frequency Bias Setting for any reason other than meeting the reliability requirement as specified by the Frequency Response Obligation.

Requirement 4

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:

- *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 as shown on FRS Form 1 and FRS Form 2 for the entirety of the participating Balancing Authorities' Areas.*

Background and Rationale

This requirement reflects the operating principles first established by NERC Policy 1 and is similar to Requirement R6 of the approved BAL-003-0.1b standard. Overlap Regulation Service is a method of providing regulation service in which the Balancing Authority providing the regulation service incorporates another Balancing Authority's actual interchange, frequency response, and schedules into the providing Balancing Authority's AGC/ACE equation.

As noted earlier, a BA that is providing Overlap Regulation will report the sum of the Bias Settings in its FRS Form 1. Balancing Authorities receiving Overlap Regulation Service have an ACE and Frequency Bias Setting equal to zero (0).

How this Standard Meets the FERC Order No. 693 Directives

FERC Directive

The following is the relevant paragraph of Order No. 693.

> *Accordingly, the Commission approves Reliability Standard BAL-003-0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to BAL-003-0 through the Reliability Standards development process that: (1) includes Levels of Non-Compliance; (2) determines the appropriate periodicity of frequency response surveys necessary to ensure that Requirement R2 and other requirements of the Reliability Standard are being met, and to modify Measure M1 based on that determination and (3) defines the necessary amount of Frequency Response needed for Reliable Operation for each balancing authority with methods of obtaining and measuring that the frequency response is achieved.*

1. Levels of Non-Compliance

VRFs and VSLs are an equally effective way of assigning compliance elements to the standard.

2. Determine the appropriate periodicity of frequency response surveys necessary to ensure that Requirement R2 and other Requirements of the Reliability Standard are met

BAL-003 V0 R2 (the basis of Order No. 693) deals with the calculation of Frequency Bias Setting such that it reflects natural Frequency Response.

The drafting team has determined that a sample size on the order of at least 20 events is necessary to have a high confidence in the estimate of a BA's Frequency Response. Selection of the frequency excursion events used for analysis will be done via a method outlined in Attachment A to the Standard.

On average, these events will represent the largest 2-3 "clean" frequency excursions occurring each month.

Since Frequency Bias Setting is an annual obligation, the survey of the at least 20 frequency excursion events will occur once each year.

3. Define the necessary amount of Frequency Response needed for Reliable Operation for each Balancing Authority with methods of obtaining and measuring that the frequency response is achieved

Necessary Amount of Frequency Response

The drafting team has proposed the following approach to defining the necessary amount of frequency response. In general, the goal is to avoid triggering the first step of under-frequency load shedding (UFLS) in the given Interconnection for reasonable contingencies expected. The

methodology for determining each Interconnection's and Balancing Authority's obligation is outlined in Attachment A to the Standard.

It should be noted the standard cannot guarantee there will never be a triggering of UFLS as the magnitude of "point C" differs throughout an interconnection during a disturbance and there are local areas that see much wider swings in frequency.

The contingency protection criterion is the largest reasonably expected contingency in the Interconnection. This can be based on the largest observed credible contingency in the previous 10 years or the largest Category C event for the Interconnection.

Attachment A to the standard presents the base obligation by Interconnection and adds a Reliability Margin. The Reliability Margin included addresses the difference between Points B and C and accounts for variables.

For multiple BA interconnections, the Frequency Response Obligation is allocated to BAs based on size. This allocation will be based on the following calculation:

$$\mathrm{FRO_{BA}} = \mathrm{FRO_{Int}} \times \frac{\text{Annual Gen}_{\mathrm{BA}} + \text{Annual Load}_{\mathrm{BA}}}{\text{Annual Gen}_{\mathrm{Int}} + \text{Annual Load}_{\mathrm{Int}}}$$

Methods of Obtaining Frequency Response

The drafting team believes the following are valid methods of obtaining Frequency Response:

- Regulation services.
- Contractual service. The drafting team has developed an approach to obtain a contractual share of Frequency Response from Adjacent Balancing Authorities. See FRS Form 1. While the final rules with regard to contractual services are being defined, the current expectation is that the ERO and the associated Region(s) should be notified beforehand and that the service be at least 6 months in duration.
- Through a tariff (e.g. Frequency Response and regulation service).
- From generators through an interconnection agreement.
- Contract with an internal resource or loads (The drafting team encourages the development of a NAESB business practice for Frequency Response service for linear (droop) and stepped (e.g. LaaR in Texas) response).

Since NERC standards should not prescribe or preclude any particular market related service, BAs and FRSGs may use whatever is most appropriate for their situation.

Measuring that the Frequency Response is Achieved

FRS Form 1 and the underlying data retained by the BA will be used for measuring whether Frequency Response was provided. FRS Form 1 will provide the guidance on how to account for and measure Frequency Response.

Going Beyond the Directive

Based on the combined operating experience of the SDT, the drafting team consensus is that each Interconnection has sufficient Frequency Response. If margins decline, there may be a need for additional standards or tools. The drafting team and the Resources Subcommittee are working with the ERO on its Frequency Response Initiative to develop processes and good practices so the Interconnections are prepared. These good practices and tools are described in the following section.

The drafting team is also evaluating a risk-based approach for basing the Interconnection Frequency Response Obligation on an historic probability density of frequency error, and for allocating the obligation on the basis of the Balancing Authority's average annual ACE share of frequency error. This allocation method uses the inverse of the rationale for allocating the CPS1 epsilon requirement by Bias share.

Good Practices and Tools

Background

This section outlines tips and tools to help Balancing authorities meet the Frequency Response Standard or to operate more reliably. If you have suggested additions, please send them to balancing@nerc.com.

Identifying and Estimating Frequency Responsive Reserves

Knowing the quantity and depth of frequency responsive reserves in real time is a possible next step to being better prepared for the next event. The challenge in achieving this is having the knowledge of the capabilities of all sources of frequency response. Presently the primary source of Frequency Response remains with the generation resources in our fleets.

Understanding how each of these sources performs to changes in system frequency and knowing their limitations would improve the BA's ability to measure frequency responsive reserves. Presently there are only guidelines, criteria and protocols in some regions of the industry that identify specific settings and performance expectations of Primary Frequency Response of resources.

One method of gaining a better understanding of performance is to measure performance during actual events that occur on the system. Measuring performance during actual events would only provide feedback for performance during that specific event and would not provide insight into depth of response or other limitations.

Repeated measurements will increase confidence in expected performance. NERC modeling standards are in process to be revised that will improve the BA's insight into predicting available frequency responsive reserves. However, knowing how resources are operated, what modes of operation provide sustained Primary Frequency Response and knowing the operating range of this response would give the BA the knowledge to accurately predict frequency response and the amount of frequency responsive reserves available in real time.

Some benefits have been realized by communicating to generation resources (GO) the importance of operating in modes that allow Primary Frequency Response to be sustained by the control systems of the resource. Other improvements in implementation of Primary Frequency Response have been achieved through improved settings on turbine governors through the elimination of "step" frequency response with the simultaneous reduction in governor dead-band settings.

Improvements in the full AGC control loop of the generating resource, which accounts for the expected Primary Frequency Response, have improved the delivery of quality Primary Frequency Response while minimizing secondary control actions of generators. Some of these actions can provide quick improvement in delivery of Primary Frequency Response.

Once Primary Frequency Response sources are known, the BA could calculate available reserves that are frequency responsive. Planning for these reserves during normal and emergency operations could be developed and added to the normal planning process.

Using FRS Form 1 Data

The information collected for this standard can be supplemented by a few data points to provide the Balancing Authority useful tools and information. The BA could do a regression analysis of its frequency response against the following values:

- Load (value A).
- Interchange (Value A).
- Total generation.
- Spinning reserve.

While the last two values above are not part of Form 1, they should be readily available. Small BAs might even include headroom on its larger generators as part of the regression.

The regression would provide a formula the BA could program in its EMS to present the operator a real time estimate of the BA's Frequency Response.

Statistical outliers in the regression would point to cases meriting further inspection to find causes of low Frequency Response or opportunities for improvement.

Tools

Single generating resource performance evaluation tools for steam turbine, combustion turbine (simple cycle or combined cycle) and for intermittent resources are available at the following link. http://texasre.org/standards_rules/standardsdev/rsc/sar003/Pages/Default.aspx.

These tools and the regional standard associated with them are in their final stages of development in the Texas region.

These tools will be posted on the NERC website.

References

NERC *Frequency Response Characteristic Survey Training Document* (Found in the NERC Operating Manual)

NERC Resources Subcommittee Position Paper on Frequency Response

NERC TIS Report *Interconnection Criteria for Frequency Response Requirements (for the Determination Interconnection Frequency Response Obligations (IFRO)*

Frequency Response Standard Field Trial Analysis, September 17, 2012

Appendix 1 - Data Quality Concerns Related To The Use Of The Actual Net Interchange Value

Actual net interchange for a typical Balancing Authority (BA) is the summation of its tie lines to other BAs. In some cases, there are pseudo-ties in it which reflect the effective removal or addition of load and/or generation from another BA, or it could include supplemental regulation as well. But in the typical scenario, actual net interchange values that are extracted from EMS data archiving can be influenced by data latency times in the data acquisition process, and also any timestamp skewing in the archival process.

Of greater concern, however, are the inevitable variations of other operating phenomena occurring concurrently with a frequency event. The impacts of these phenomena are superimposed on actual net interchange values along with the frequency response that we wish to measure through the use of the actual net interchange value.

To explore this issue further, let's begin with the idealized condition:

- frequency is fairly stable at some value near or a little below 60 Hz
- ACE of the non-contingent BA of interest is 0 and has been 0 for an extended period, and AGC control signals have not been issued recently
- Actual net interchange is "on schedule", and there are no schedule changes in the immediate future
- BA load is flat
- All generators not providing AGC are at their targets
- Variable generation such as wind and solar are not varying
- Operators have not directed any manual movements of generation recently

And when the contingency occurs in this idealized state, the change in actual net interchange will be measuring only the decline in load due to lesser frequency and generator governor response, and, none of the contaminating influences. While the ACE may become negative due to the actual frequency response being less than that called for by the frequency bias setting within the BA's AGC system, this contaminating influence on measuring frequency response will not appear in the actual net interchange value if the measurement interval ends before the generation on AGC responds.

Now let's explore the sensitivity of the resultant frequency response sampling to the relaxation of these idealized circumstances.

1. The "60 Hz load" increases moderately due to time of day concurrent with the frequency event. If the frequency event happens before AGC or operator-directed manual load adjustments occur, then the actual net interchange will be reduced by the moderate increase in load and the frequency response will be underestimated. But if the frequency event happens while AGC response and/or manual adjustments occur, then the actual net interchange will be increased by the AGC response (and/or manual adjustments) and the frequency response will be overestimated.

2. The “60 Hz load” decreases moderately due to time of day concurrent with the frequency event. If the frequency event happens before AGC or operator-directed manual load adjustments occur, then the actual net interchange will be increased by the moderate reduction in load and the frequency response will be overestimated. But if the frequency event happens while AGC response and/or manual adjustments occur, then the actual net interchange will be decreased by the AGC response (and/or manual adjustments) and the frequency response will be underestimated.
3. In anticipation of increasing load during the next hour, the operator increases manual generation before the load actually appears. If the frequency event happens while the generation “leading” the load is increasing, then the actual net interchange will be increased by the increase in manual generation and the frequency response will be overestimated. But if the frequency event occurs when the result of AGC signals sent to offset the operator’s leading actions take effect, then the actual net interchange will be decreased and the frequency response is underestimated.
4. In anticipation of decreasing load during the next hour, the operator decreases manual generation before the load actually declines. If the frequency event happens while the generation “leading” the load downward is decreasing, then the actual net interchange will be decreased by the reduction in manual generation and the frequency response will be underestimated. But if the frequency event occurs when the result of AGC signals sent to offset the operator’s leading actions take effect, then the actual net interchange will be increased and the frequency response is overestimated.
5. A schedule change to export more energy is made at 5 minutes before the top of the hour. The BA’s “60 Hz load” is not changing. The schedule change is small enough that the operator is relying on upward movement of generators on AGC to provide the additional energy to be exported. The time at which the AGC generators actually begin to provide the additional energy is dependent on how much time passes before the AGC algorithm gets out of its deadbands, the individual generator control errors get large enough for sending out the control signal, and maybe 20 seconds to 3 minutes for the response to be effected. The key point here is that it is not clear when the effects of a schedule change, as manifested in a change in generation and then ultimately a change in actual net interchange, will occur.
6. With the expected penetration of wind in the near future, unanticipated changes in their output will tend to affect actual net interchange and add noise to the frequency response observation process.

To a greater or lesser extent, 1 through 4 above are happening continuously for the most part with most BAs in the Eastern and Western Interconnections. The frequency response is buried within the typical hour to hour operational cacophony superimposed on actual net interchange values. The choice of metrics will be important to artfully extract frequency response from the noise and other unrepresentative error.

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Proposed Resource Loss Protection Criteria

Background and Current Methodologies

The Resource Loss Protection Criteria (RLPC) is the respective Interconnection design resource loss in MW, ~~-~~which is used to determine the Interconnection Frequency Response Obligation (IFRO).
An "N-2 Event" is defined as a single initiating event that leads to multiple (two or more) electrical facilities being removed from service. Examples of this are breaker failure events, bus faults, or double circuit tower outages.

Previously, the RLPC has been calculated from the largest N-2 events identified in each Interconnection, except for the Eastern Interconnection. In the Eastern Interconnection, the RLPC has been calculated using the largest single event in the previous ten years.

The RLPC value should be set for each Interconnection such that the underfrequency load shedding safety net is not activated for the largest N-2 Event. The ~~P~~previous BAL-003 IFRO methodology determined that the largest N-2 Event should not precipitate an underfrequency load shedding event. Ideally, the RLPC value should always equal or exceed the largest N-2 Event. If the RLPC is set to a larger value than the largest N-2 Event, the probability of an underfrequency load shedding event decreases. If the RLPC value is set to a value less than the largest N-2 Event, the probability of an underfrequency load shedding event increases.

A quantitative approach ~~to~~for selecting the RLPC can be implemented that minimizes the need for detailed system analysis to be performed annually.

Currently, each Balancing Authority (BA) or Reserve Sharing Group (RSG) determines its Most Severe Single Contingency (MSSC) with respect to resource loss as required by BAL-002-2(i), Requirement R2. The MSSC calculation is done in Real-time operations based on actual system configuration.

Relevant Definitions

For convenience, the definitions of the following terms defined in the Glossary of Terms used in NERC Reliability Standards are provided below. Where a conflict exists between the definition provided here and the definition in the Glossary, the definition in the Glossary shall control.

Most Severe Single Contingency:
The Balancing Contingency Event, due to a single contingency identified using system models maintained within the RSG or a BA's area that is not part of a RSG, that would result in the greatest loss (measured in Megawatts (MWs) of resource output used by the RSG or a BA that is not participating as a member of a RSG at the time of the event to meet Firm Demand and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the Sink Balancing Authority).

Balancing Contingency Event:
Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by one minute or less.

A. Sudden loss of generation:
   a. Due to:
      i. unit tripping, or
      ii. loss of generator Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's System, or
      iii. sudden unplanned outage of transmission Facility.
   b. And that causes an unexpected change to the responsible entity's Area Control ~~Area~~ Error (ACE).

B. Sudden loss of an Import, due to forced outage of transmission equipment that causes an unexpected imbalance between generation and Demand on the Interconnection.

C. Sudden restoration of a Demand that was used as a resource that causes an unexpected change to the responsible entity's ACE.

Interconnection:
A geographic area in which the operation of Bulk Power System components is synchronized such that the failure of one or more of such components may adversely affect the ability of the operators of other components within the system to maintain Reliable Operation of the Facilities within their control. When capitalized, any one of the four major electric system networks in North America: Eastern, Western, ERCOT and Quebec.

Proposal

The Interconnection RLPC is calculated based on a resource loss in accordance with the following process:

NERC will request ~~Balancing Authorities~~BAs to provide: their two largest resource loss values and largest resource loss due to an N-1 or N-2 RAS event or largest resource as described above. This will facilitate comparison between the existing Interconnection RLPC values and the RLPC values in use. This data submission will be needed to complete the calculation of the RLPC and IFRO.

~~NERC will request Balancing Authorities or Frequency Response Sharing Groups to provide: their two largest resource loss values and largest resource loss due to an N-1 or N-2 RAS event or largest resource as described above. This will facilitate comparison between the existing Interconnection RLPC values and the RLPC values in use. This data submission will be voluntary on the part of the Balancing Authorities but will be needed to complete the calculation of the RLPC and IFRO.~~

~~Balancing Authorities~~BAs determine the two largest ~~potential~~ resource losses for the next operating year based on a review of the following items:

- The two largest Balancing Contingency Events due to a single contingency identified using system models in terms of loss measured by megawatt loss in a normal system configuration (N-0). (An abnormal system configuration is not used to determine the RLPC.)
- The two largest units in the BA Area, regardless of shared ownership/responsibility.
- The two largest Remedial Action Scheme (RAS) resource losses (if any) which are initiated by single (N-1) contingency events.

The BA provides these two numbers determined above as Resource Loss A and Resource Loss B in the FRS Form 1.

The BA should then provide the largest resource loss due to RAS operations (if any) which is initiated by a multiple contingency (N-2) event (RLPC cannot be lower than this value). If th~~is~~e RAS impacts more than a single BA, one BA is asked to take the lead and sum all resources lost due to the RAS event and provide that information.

The calculated RLPC should meet or exceed any credible N-2 resource loss event.
The host BA (or planned host BA) where jointly-owned resources are physically located, should be the only BA to report that resource. The full ratings of the resource, not the fractional shares, should be reported.

Direct-current (DC) ties to asynchronous resources (such as DC ties between Interconnections, or the Manitoba Hydro Dorsey bi-pole ties to their northern asynchronous generation). DC lines such as the Pacific DC Intertie, which ties two sections of the same synchronous interconnection together, should not be reported. A single pole block with normal clearing in a monopole or bi-pole high-voltage direct current system is a single contingency.

For a hypothetical four-BA Interconnection, Plant 1, in BA1, has two generators rated at 1200 MW each. Plant 2, in BA2 has a generator rated at 1400 MW. BA2's next largest contingency is 1000 MW. The two largest resource losses for BA3 and BA4 are listed below.

BA1	Resource Loss A = 1200 MW	Resource Loss B = 1200 MW	Both at Plant 1 (N-2)
BA2	Resource Loss A= 1400 MW	Resource Loss B = 1000 MW	Electrically separate
BA3	Resource Loss A = 1000 MW	Resource Loss B = 800 MW	Electrically separate
BA4	Resource Loss A = 1500 MW (DC TIE)	Resource Loss B= 500 MW	Electrically separate

The ERO would apply the RLPC selection methodology described above to determine the RLPC for the Interconnection. Using this methodology, results in the following:

Largest Resource Loss = 1500 MW
Second Largest Resource Loss = 1400 MW
Summation of two largest resource losses = 2900 MW
Interconnection RLPC = 2900 MW

If only the N-2 Event was applied, the RLPC for the Interconnection would be 2400 MW. The summation of the two largest Interconnection Resource Losses will equal or exceed, but never fall short of, the N-2 Event scenario.

In order to evaluate RAS resource loss, single (N-1) and multiple (N-2) contingency events should be evaluated.

Hypothetically, in an Interconnection:

BA1 RAS = 2850 MW N-2 RAS event
BA1 Resource Loss A = 1150 MW
BA1 Resource Loss B = 800 MW
BA2 Resource Loss A = 1380 MW
BA2 Resource Loss B = 1380 MW
BA3 RAS = 1000 MW N-1 RAS event
BA3 Resource Loss A = 800 MW
BA3 Resource Loss B = 700 MW

In this ~~case~~case, the ERO would determine the RLPC as ~~follows,~~follows~~;~~: the summation of the two largest resource losses ~~are~~is 2760 MW. Since the N-2 RAS event exceeds the summation of the two largest single contingency events, the RLPC is the N-2 RAS event, or 2850 MW.

~~North American~~ Interconnection ~~RPLC~~ RLPC Values

Based on initial review, the numbers below ~~are believed to~~would be representative of the RLPC for each Interconnection.

Eastern Interconnection:
Present RLPC = 4500 MW Load Credit = 0 MW
~~MSSC1~~RESOURCE LOSS A = 1732 MW
~~MSSC2~~RESOURCE LOSS B = 1477 MW
Proposed RLPC = 3209 MW

Western Interconnection:
Present RLPC = 2626 MW Load Credit = 120 MW
~~MSSC1~~RESOURCE LOSS A = 1505 MW
~~MSSC2~~RESOURCE LOSS B = 1344 MW
N-2 RAS = 2850 MW
Proposed RLPC = 2850 MW

ERCOT:
Present RLPC = 2750 MW Load Credit = 1209 MW
~~MSSC1~~RESOURCE LOSS A = 1375 MW
~~MSSC2~~RESOURCE LOSS B = 1375 MW
Proposed RLPC = 2750 MW

Quebec Interconnection:
Present RLPC = 1700 MW Load Credit = 0 MW
~~MSSC1~~RESOURCE LOSS A = 1000 MW
~~MSSC2~~RESOURCE LOSS B = 1000 MW
Proposed RLPC = 2000 MW

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

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 initial ballot	August 2018 – September 2018
10-day final ballot	September 2018
NERC Board adoption	November 2018

Upon Board adoption, the rationale boxes will be moved to the Supplemental Material Section.

A. Introduction

1. Title: Physical Security

2. Number: CIP-014-32

3. Purpose: To identify and protect Transmission stations and Transmission substations, and their associated primary control centers, that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection.

4. Applicability:

4.1. Functional Entities:

4.1.1 Transmission Owner that owns a Transmission station or Transmission substation that meets any of the following criteria:

4.1.1.1 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.

4.1.1.2 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

4.1.1.3 Transmission Facilities at a single station or substation location that are identified by the ~~its Reliability Coordinator,~~ Planning Coordinator~~,~~ or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation ~~as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies~~.

4.1.1.4 Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.

4.1.2 Transmission Operator.

Exemption: Facilities in a "protected area," as defined in 10 C.F.R. § 73.2, within the scope of a security plan approved or accepted by the Nuclear Regulatory Commission are not subject to this Standard; or, Facilities within the scope of a security plan approved or accepted by the Canadian Nuclear Safety Commission are not subject to this Standard.

5. Effective Dates:

See Implementation Plan for CIP-014-32.

6. Background:

~~This~~ Reliability Standard CIP-014-2 addresses the directives from the FERC order issued March 7, 2014, *Reliability Standards for Physical Security Measures*, 146 FERC ¶ 61,166 (2014), which required NERC to develop a physical security reliability standard(s) to identify and protect facilities that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection.

B. Requirements and Measures

R1. Each Transmission Owner shall perform an initial risk assessment and subsequent risk assessments of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria specified in Applicability Section 4.1.1. The initial and subsequent risk assessments shall consist of a transmission analysis or transmission analyses designed to identify the Transmission station(s) and Transmission substation(s) that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection. *[VRF: High; Time-Horizon: Long-term Planning]*

1.1. Subsequent risk assessments shall be performed:

- At least once every 30 calendar months for a Transmission Owner that has identified in its previous risk assessment (as verified according to Requirement R2) one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection; or

- At least once every 60 calendar months for a Transmission Owner that has not identified in its previous risk assessment (as verified according to Requirement R2) any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection.

1.2. The Transmission Owner shall identify the primary control center that operationally controls each Transmission station or Transmission substation identified in the Requirement R1 risk assessment.

M1. Examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation of the risk assessment of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria in Applicability Section 4.1.1 as specified in Requirement R1. Additionally, examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation of the identification of the primary control center that operationally controls each Transmission station or Transmission substation identified in the Requirement R1 risk assessment as specified in Requirement R1, Part 1.2.

R2. Each Transmission Owner shall have an unaffiliated third party verify the risk assessment performed under Requirement R1. The verification may occur concurrent with or after the risk assessment performed under Requirement R1. *[VRF: Medium; Time-Horizon: Long-term Planning]*

2.1. Each Transmission Owner shall select an unaffiliated verifying entity that is either:

- A registered Planning Coordinator, Transmission Planner, or Reliability Coordinator; or
- An entity that has transmission planning or analysis experience.

2.2. The unaffiliated third party verification shall verify the Transmission Owner's risk assessment performed under Requirement R1, which may include recommendations for the addition or deletion of a Transmission station(s) or Transmission substation(s). The Transmission Owner shall ensure the verification is completed within 90 calendar days following the completion of the Requirement R1 risk assessment.

2.3. If the unaffiliated verifying entity recommends that the Transmission Owner add a Transmission station(s) or Transmission substation(s) to, or remove a Transmission station(s) or Transmission substation(s) from, its identification under Requirement R1, the Transmission Owner shall either, within 60 calendar days of completion of the verification, for each recommended addition or removal of a Transmission station or Transmission substation:

- Modify its identification under Requirement R1 consistent with the recommendation; or
- Document the technical basis for not modifying the identification in accordance with the recommendation.

2.4. Each Transmission Owner shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party verifier and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.

M2. Examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation that the Transmission Owner completed an unaffiliated third party verification of the Requirement R1 risk assessment and satisfied all of the applicable provisions of Requirement R2, including, if applicable, documenting the technical basis for not modifying the Requirement R1 identification as specified under Part 2.3. Additionally, examples of evidence may include, but are not limited to, written or electronic documentation of procedures to protect information under Part 2.4.

R3. For a primary control center(s) identified by the Transmission Owner according to Requirement R1, Part 1.2 that a) operationally controls an identified Transmission station or Transmission substation verified according to Requirement R2, and b) is not under the operational control of the Transmission Owner: the Transmission Owner shall, within seven calendar days following completion of Requirement R2, notify the Transmission Operator that has operational control of the primary control center of

such identification and the date of completion of Requirement R2. *[VRF: Lower; Time-Horizon: Long-term Planning]*

3.1. If a Transmission station or Transmission substation previously identified under Requirement R1 and verified according to Requirement R2 is removed from the identification during a subsequent risk assessment performed according to Requirement R1 or a verification according to Requirement R2, then the Transmission Owner shall, within seven calendar days following the verification or the subsequent risk assessment, notify the Transmission Operator that has operational control of the primary control center of the removal.

M3. Examples of acceptable evidence may include, but are not limited to, dated written or electronic notifications or communications that the Transmission Owner notified each Transmission Operator, as applicable, according to Requirement R3.

R4. Each Transmission Owner that identified a Transmission station, Transmission substation, or a primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall conduct an evaluation of the potential threats and vulnerabilities of a physical attack to each of their respective Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2. The evaluation shall consider the following: *[VRF: Medium; Time-Horizon: Operations Planning, Long-term Planning]*

4.1. Unique characteristics of the identified and verified Transmission station(s), Transmission substation(s), and primary control center(s);

4.2. Prior history of attack on similar facilities taking into account the frequency, geographic proximity, and severity of past physical security related events; and

4.3. Intelligence or threat warnings received from sources such as law enforcement, the Electric Reliability Organization (ERO), the Electricity Sector Information Sharing and Analysis Center (ES-ISAC), U.S. federal and/or Canadian governmental agencies, or their successors.

M4. Examples of evidence may include, but are not limited to, dated written or electronic documentation that the Transmission Owner or Transmission Operator conducted an evaluation of the potential threats and vulnerabilities of a physical attack to their respective Transmission station(s), Transmission substation(s) and primary control center(s) as specified in Requirement R4.

R5. Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall develop and implement a documented physical security plan(s) that covers their respective Transmission station(s), Transmission substation(s), and primary control center(s). The physical security plan(s) shall be

developed within 120 calendar days following the completion of Requirement R2 and executed according to the timeline specified in the physical security plan(s). The physical security plan(s) shall include the following attributes: *[VRF: High; Time-Horizon: Long-term Planning]*

5.1. Resiliency or security measures designed collectively to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R4.

5.2. Law enforcement contact and coordination information.

5.3. A timeline for executing the physical security enhancements and modifications specified in the physical security plan.

5.4. Provisions to evaluate evolving physical threats, and their corresponding security measures, to the Transmission station(s), Transmission substation(s), or primary control center(s).

M5. Examples of evidence may include, but are not limited to, dated written or electronic documentation of its physical security plan(s) that covers their respective identified and verified Transmission station(s), Transmission substation(s), and primary control center(s) as specified in Requirement R5, and additional evidence demonstrating execution of the physical security plan according to the timeline specified in the physical security plan.

R6. Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall have an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5. The review may occur concurrently with or after completion of the evaluation performed under Requirement R4 and the security plan development under Requirement R5. *[VRF: Medium; Time-Horizon: Long-term Planning]*

6.1. Each Transmission Owner and Transmission Operator shall select an unaffiliated third party reviewer from the following:

- An entity or organization with electric industry physical security experience and whose review staff has at least one member who holds either a Certified Protection Professional (CPP) or Physical Security Professional (PSP) certification.
- An entity or organization approved by the ERO.
- A governmental agency with physical security expertise.

- An entity or organization with demonstrated law enforcement, government, or military physical security expertise.

6.2. The Transmission Owner or Transmission Operator, respectively, shall ensure that the unaffiliated third party review is completed within 90 calendar days of completing the security plan(s) developed in Requirement R5. The unaffiliated third party review may, but is not required to, include recommended changes to the evaluation performed under Requirement R4 or the security plan(s) developed under Requirement R5.

6.3. If the unaffiliated third party reviewer recommends changes to the evaluation performed under Requirement R4 or security plan(s) developed under Requirement R5, the Transmission Owner or Transmission Operator shall, within 60 calendar days of the completion of the unaffiliated third party review, for each recommendation:

- Modify its evaluation or security plan(s) consistent with the recommendation; or

- Document the reason(s) for not modifying the evaluation or security plan(s) consistent with the recommendation.

6.4. Each Transmission Owner and Transmission Operator shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party reviewer and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.

M6. Examples of evidence may include, but are not limited to, written or electronic documentation that the Transmission Owner or Transmission Operator had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 as specified in Requirement R6 including, if applicable, documenting the reasons for not modifying the evaluation or security plan(s) in accordance with a recommendation under Part 6.3. Additionally, examples of evidence may include, but are not limited to, written or electronic documentation of procedures to protect information under Part 6.4.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence during an on-site visit to show that it was compliant for the full time period since the last audit.

The Transmission Owner and Transmission Operator shall keep data or evidence to show compliance, as identified below, unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation.

The responsible entities shall retain documentation as evidence for three years.

If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records, subject to the confidentiality provisions of Section 1500 of the Rules of Procedure and the provisions of Section 1.4 below.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints Text

1.4. Additional Compliance Information

Confidentiality: To protect the confidentiality and sensitive nature of the evidence for demonstrating compliance with this standard, all evidence will be retained at the Transmission Owner's and Transmission Operator's facilities.

2. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Long-term Planning**	**High**	The Transmission Owner performed an initial risk assessment but did so after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to two calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could	The Transmission Owner performed an initial risk assessment but did so more than two calendar months after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to four calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable	The Transmission Owner performed an initial risk assessment but did so more than four calendar months after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to six calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could	The Transmission Owner performed an initial risk assessment but did so more than six calendar months after the date specified in the implementation plan for performing the initial risk assessment; OR The Transmission Owner failed to perform an initial risk assessment; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 30 calendar months but less than or equal to 32 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an	or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 32 calendar months but less than or equal to 34 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an	result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 34 calendar months but less than or equal to 36 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection	stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after more than 36 calendar months; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability,

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Interconnection performed a subsequent risk assessment but did so after 60 calendar months but less than or equal to 62 calendar months.	Interconnection performed a subsequent risk assessment but did so after 62 calendar months but less than or equal to 64 calendar months.	performed a subsequent risk assessment but did so after 64 calendar months but less than or equal to 66 calendar months; OR The Transmission Owner performed a risk assessment but failed to include Part 1.2.	uncontrolled separation, or Cascading within an Interconnection failed to perform a risk assessment; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after more than 66 calendar months;

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						OR The Transmission Owner that has not identified in its previous risk assessment any Transmission station and Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection failed to perform a subsequent risk assessment.
R2	**Long-term Planning**	**Medium**	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so in more than 90 calendar days but	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 100 calendar days but	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 110 calendar days but less than or equal to	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 120 calendar days

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			less than or equal to 100 calendar days following completion of Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part 2.3 but did so more than 60 calendar days and less than or equal to 70 calendar days from completion of the third party verification.	less than or equal to 110 calendar days following completion of Requirement R1; Or The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part 2.3 but did so more than 70 calendar days and less than or equal to 80 calendar days from completion of the third party verification.	120 calendar days following completion of Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part 2.3 but did so more than 80 calendar days from completion of the third party verification; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed	following completion of Requirement R1; OR The Transmission Owner failed to have an unaffiliated third party verify the risk assessment performed under Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but failed to implement procedures for protecting information per Part 2.4.

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					under Requirement R1 but failed to modify or document the technical basis for not modifying its identification under R1 as required by Part 2.3.	
R3	**Long-term Planning**	**Lower**	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than seven calendar days and less than or equal to nine calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than nine calendar days and less than or equal to 11 calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than 11 calendar days and less than or equal to 13 calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that operates the primary control center	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than 13 calendar days following the completion of Requirement R2; OR The Transmission Owner failed to notify the Transmission Operator that it operates a control

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			operates the primary control center of the removal from the identification in Requirement R1 but did so more than seven calendar days and less than or equal to nine calendar days following the verification or the subsequent risk assessment.	operates the primary control center of the removal from the identification in Requirement R1 but did so more than nine calendar days and less than or equal to 11 calendar days following the verification or the subsequent risk assessment.	of the removal from the identification in Requirement R1 but did so more than 11 calendar days and less than or equal to 13 calendar days following the verification or the subsequent risk assessment.	center identified in Requirement R1; OR The Transmission Owner notified the Transmission Operator that operates the primary control center of the removal from the identification in Requirement R1 but did so more than 13 calendar days following the verification or the subsequent risk assessment. OR The Transmission Owner failed to notify the Transmission Operator that operates the primary control center of the removal from the

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						identification in Requirement R1.
R4	**Operations Planning, Long-term Planning**	**Medium**	N/A	The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but failed to consider one of Parts 4.1 through 4.3 in the evaluation.	The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but failed to consider two of Parts 4.1 through 4.3 in the evaluation.	The Responsible Entity failed to conduct an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1; OR The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						substation(s), and primary control center(s) identified in Requirement R1 but failed to consider Parts 4.1 through 4.3.
R5	**Long-term Planning**	**High**	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 120 calendar days but less than or equal to 130 calendar days after completing Requirement R2; OR	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 130 calendar days but less than or equal to 140 calendar days after completing Requirement R2; OR	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 140 calendar days but less than or equal to 150 calendar days after completing Requirement R2; OR	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 150 calendar days after completing the verification in Requirement R2; OR

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include one of Parts 5.1 through 5.4 in the plan.	The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include two of Parts 5.1 through 5.4 in the plan.	The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include three of Parts 5.1 through 5.4 in the plan.	The Responsible Entity failed to develop and implement a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2. OR The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						primary control center(s) identified in Requirement R1 and verified according to Requirement 2 but failed to include Parts 5.1 through 5.4 in the plan.
R6	**Long-term Planning**	**Medium**	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so in more than 90 calendar days but less than or equal to 100 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so in more than 100 calendar days but less than or equal to 110 calendar days; OR The Responsible Entity had an unaffiliated third party review the	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so more than 110 calendar days but less than or equal to 120 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security	The Responsible Entity failed to have an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 in more than 120 calendar days; OR The Responsible Entity failed to have an unaffiliated third party review the evaluation performed under

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			under Requirement R4 and the security plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 60 calendar days and less than or equal to 70 calendar days following completion of the third party review.	evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 70 calendar days and less than or equal to 80 calendar days following completion of the third party review.	plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 80 calendar days following completion of the third party review; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did not document the reason for not modifying the security plan(s) as specified in Part 6.3.	Requirement R4 and the security plan(s) developed under Requirement R5; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but failed to implement procedures for protecting information per Part 6.4.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	October 1, 2015	Effective Date	New
2	April 16, 2015	Revised to meet FERC Order 802 directive to remove “widespread”.	Revision
2	May 7, 2015	Adopted by the NERC Board of Trustees	
2	July 14, 2015	FERC Letter Order in Docket No. RD15-4-000 approving CIP-014-2	

Guidelines and Technical Basis

Section 4 Applicability

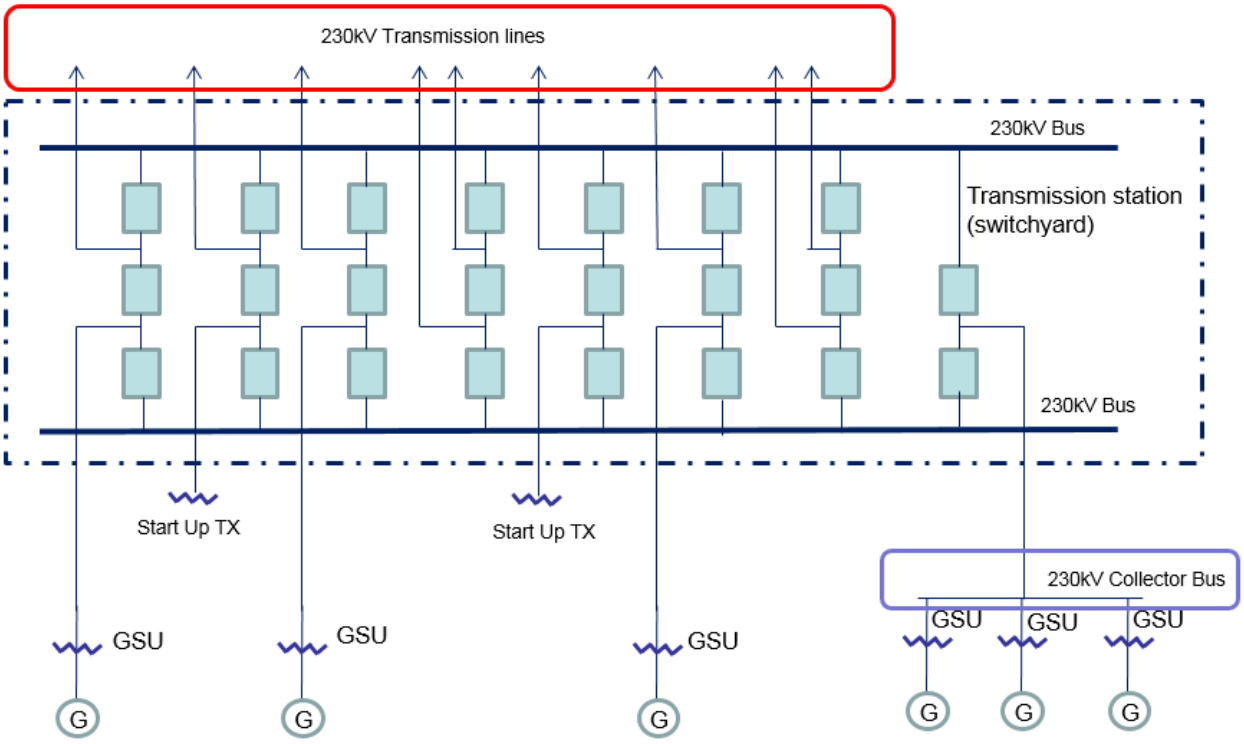
The purpose of Reliability Standard CIP-014 is to protect Transmission stations and Transmission substations, and their associated primary control centers that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. To properly include those entities that own or operate such Facilities, the Reliability Standard CIP-014 first applies to Transmission Owners that own Transmission Facilities that meet the specific criteria in Applicability Section 4.1.1.1 through 4.1.1.4. The Facilities described in Applicability Section 4.1.1.1 through 4.1.1.4 mirror those Transmission Facilities that meet the bright line criteria for "Medium Impact" Transmission Facilities under Attachment 1 of Reliability Standard CIP-002-5.1. Each Transmission Owner that owns Transmission Facilities that meet the criteria in Section 4.1.1.1 through 4.1.1.4 is required to perform a risk assessment as specified in Requirement R1 to identify its Transmission stations and Transmission substations, and their associated primary control centers, that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. The Standard Drafting Team (SDT) expects this population will be small and that many Transmission Owners that meet the applicability of this standard will not actually identify any such Facilities. Only those Transmission Owners with Transmission stations or Transmission substations identified in the risk assessment (and verified under Requirement R2) have performance obligations under Requirements R3 through R6.

This standard also applies to Transmission Operators. A Transmission Operator's obligations under the standard, however, are only triggered if the Transmission Operator is notified by an applicable Transmission Owner under Requirement R3 that the Transmission Operator operates a primary control center that operationally controls a Transmission station(s) or Transmission substation(s) identified in the Requirement R1 risk assessment. A primary control center operationally controls a Transmission station or Transmission substation when the control center's electronic actions can cause direct physical action at the identified Transmission station or Transmission substation, such as opening a breaker, as opposed to a control center that only has information from the Transmission station or Transmission substation and must coordinate direct action through another entity. Only Transmission Operators who are notified that they have primary control centers under this standard have performance obligations under Requirements R4 through R6. In other words, primary control center for purposes of this Standard is the control center that the Transmission Owner or Transmission Operator, respectively, uses as its primary, permanently-manned site to physically operate a Transmission station or Transmission substation that is identified in Requirement R1 and verified in Requirement R2. Control centers that provide back-up capability are not applicable, as they are a form of resiliency and intentionally redundant.

The SDT considered several options for bright line criteria that could be used to determine applicability and provide an initial threshold that defines the set of Transmission stations and Transmission substations that would meet the directives of the FERC order on physical security (*i.e.*, those that could cause instability, uncontrolled separation, or Cascading within an

Interconnection). The SDT determined that using the criteria for Medium Impact Transmission Facilities in Attachment 1 of CIP-002-5.1 would provide a conservative threshold for defining which Transmission stations and Transmission substations must be included in the risk assessment in Requirement R1 of CIP-014. Additionally, the SDT concluded that using the CIP-002-5.1 Medium Impact criteria was appropriate because it has been approved by stakeholders, NERC, and FERC, and its use provides a technically sound basis to determine which Transmission Owners should conduct the risk assessment. As described in CIP-002-5.1, the failure of a Transmission station or Transmission substation that meets the Medium Impact criteria could have the capability to result in ~~exceeding one or more Interconnection Reliability Operating Limits (IROLs)~~instability, uncontrolled separation, or Cascading. The SDT understands that using this bright line criteria to determine applicability may require some Transmission Owners to perform risk assessments under Requirement R1 that will result in a finding that none of their Transmission stations or Transmission substations would pose a risk of instability, uncontrolled separation, or Cascading within an Interconnection. However, the SDT determined that higher bright lines could not be technically justified to ensure inclusion of all Transmission stations and Transmission substations, and their associated primary control centers that, if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. Further guidance and technical basis for the bright line criteria for Medium Impact Facilities can be found in the Guidelines and Technical Basis section of CIP-002-5.1.

Additionally, the SDT determined that it was not necessary to include Generator Operators and Generator Owners in the Reliability Standard. First, Transmission stations or Transmission substations interconnecting generation facilities are considered when determining applicability. Transmission Owners will consider those Transmission stations and Transmission substations that include a Transmission station on the high side of the Generator Step-up transformer (GSU) using Applicability Section 4.1.1.1 and 4.1.1.2. As an example, a Transmission station or Transmission substation identified as a Transmission Owner facility that interconnects generation will be subject to the Requirement R1 risk assessment if it operates at 500kV or greater or if it is connected at 200 kV – 499kV to three or more other Transmission stations or Transmission substations and has an "aggregate weighted value" exceeding 3000 according to the table in Applicability Section 4.1.1.2. Second, the Transmission analysis or analyses conducted under Requirement R1 should take into account the impact of the loss of generation connected to applicable Transmission stations or Transmission substations. Additionally, the FERC order does not explicitly mention generation assets and is reasonably understood to focus on the most critical Transmission Facilities. The diagram below shows an example of a station.



Also, the SDT uses the phrase "Transmission stations or Transmission 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 (switching stations or switchyards). Therefore, the SDT chose to use both "station" and "substation" to refer to the locations where groups of Transmission Facilities exist.

On the issue of joint ownership, the SDT recognizes that this issue is not unique to CIP-014, and expects that the applicable Transmission Owners and Transmission Operators will develop memorandums of understanding, agreements, Coordinated Functional Registrations, or procedures, etc., to designate responsibilities under CIP-014 when joint ownership is at issue, which is similar to what many entities have completed for other Reliability Standards.

The language contained in the applicability section regarding the collector bus is directly copied from CIP-002-5.1, Attachment 1, and has no additional meaning within the CIP-014 standard.

Requirement R1

The initial risk assessment required under Requirement R1 must be completed on or before the effective date of the standard. Subsequent risk assessments are to be performed at least once every 30 or 60 months depending on the results of the previous risk assessment per Requirement R1, Part 1.1. In performing the risk assessment under Requirement R1, the

Transmission Owner should first identify their population of Transmission stations and Transmission substations that meet the criteria contained in Applicability Section 4.1.1. Requirement R1 then requires the Transmission Owner to perform a risk assessment, consisting of a transmission analysis, to determine which of those Transmission stations and Transmission Substations if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection. The requirement is not to require identification of, and thus, not intended to bring within the scope of the standard a Transmission station or Transmission substation unless the applicable Transmission Owner determines through technical studies and analyses based on objective analysis, technical expertise, operating experience and experienced judgment that the loss of such facility would have a critical impact on the operation of the Interconnection in the event the asset is rendered inoperable or damaged. In the November 20, 2014 Order, FERC reiterated that "only an instability that has a "critical impact on the operation of the interconnection" warrants finding that the facility causing the instability is critical under Requirement R1." The Transmission Owner may determine the criteria for critical impact by considering, among other criteria, any of the following:

- Criteria or methodology used by Transmission Planners or Planning Coordinators in TPL-001-4, Requirement R6
- NERC EOP-004-2 reporting criteria
- Area or magnitude of potential impact

The standard does not mandate the specific analytical method for performing the risk assessment. The Transmission Owner has the discretion to choose the specific method that best suites its needs. As an example, an entity may perform a Power Flow analysis and stability analysis at a variety of load levels.

Performing Risk Assessments

The Transmission Owner has the discretion to select a transmission analysis method that fits its facts and system circumstances. To mandate a specific approach is not technically desirable and may lead to results that fail to adequately consider regional, topological, and system circumstances. The following guidance is only an example on how a Transmission Owner may perform a power flow and/or stability analysis to identify those Transmission stations and Transmission substations that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. An entity could remove all lines, without regard to the voltage level, to a single Transmission station or Transmission substation and review the simulation results to assess system behavior to determine if Cascading of Transmission Facilities, uncontrolled separation, or voltage or frequency instability is likely to occur over a significant area of the Interconnection. Using engineering judgment, the Transmission Owner (possibly in consultation with regional planning or operation committees and/or ISO/RTO committee input) should develop criteria (e.g. imposing a fault near the removed Transmission station or Transmission substation) to identify a contingency or parameters that result in potential instability, uncontrolled separation, or Cascading within an Interconnection. Regional consultation on these matters is likely to be

helpful and informative, given that the inputs for the risk assessment and the attributes of what constitutes instability, uncontrolled separation, or Cascading within an Interconnection will likely vary from region-to-region or from ISO-to-ISO based on topology, system characteristics, and system configurations. Criteria could also include post-contingency facilities loadings above a certain emergency rating or failure of a power flow case to converge. Available special protection systems (SPS), if any, could be applied to determine if the system experiences any additional instability which may result in uncontrolled separation. Example criteria may include:

(a) Thermal overloads beyond facility emergency ratings;

(b) Voltage deviation exceeding ± 10%; or

(c) Cascading outage/voltage collapse; or

(d) Frequency below under-frequency load shed points

Periodicity

A Transmission Owner who identifies one or more Transmission stations or Transmission substations (as verified under Requirement R2) that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection is required to conduct a risk assessment at least once every 30 months. This period ensures that the risk assessment remains current with projected conditions and configurations in the planned system. This risk assessment, as the initial assessment, must consider applicable planned Transmission stations and Transmission substations to be in service within 24 months. The 30 month timeframe aligns with the 24 month planned to be in service date because the Transmission Owner is provided the flexibility, depending on its planning cycle and the frequency in which it may plan to construct a new Transmission station or Transmission substation to more closely align these dates. The requirement is to conduct the risk assessment at least once every 30 months, so for a Transmission Owner that believes it is better to conduct a risk assessment once every 24 months, because of its planning cycle, it has the flexibility to do so.

Transmission Owners that have not identified any Transmission stations or Transmission substations (as verified under Requirement R2) that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection are unlikely to see changes to their risk assessment in the Near-Term Planning Horizon. Consequently, a 60 month periodicity for completing a subsequent risk assessment is specified.

Identification of Primary Control Centers

After completing the risk assessment specified in Requirement R1, it is important to additionally identify the primary control center that operationally controls each Transmission station or Transmission substation that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection. A primary control center "operationally controls" a Transmission station or Transmission substation when the control

center's electronic actions can cause direct physical actions at the identified Transmission station and Transmission substation, such as opening a breaker.

Requirement R2

This requirement specifies verification of the risk assessment performed under Requirement R1 by an entity other than the owner or operator of the Requirement R1 risk assessment.

A verification of the risk assessment by an unaffiliated third party, as specified in Requirement R2, could consist of:

1. Certifying that the Requirement R1 risk assessment considers the Transmission stations and Transmission substations identified in Applicability Section 4.1.1.
2. Review of the model used to conduct the risk assessment to ensure it contains sufficient system topology to identify Transmission stations and Transmission substations that if rendered inoperable or damaged could cause instability, uncontrolled separation, or Cascading within an Interconnection.
3. Review of the Requirement R1 risk assessment methodology.

This requirement provides the flexibility for a Transmission Owner to select from unaffiliated registered and non-registered entities with transmission planning or analysis experience to perform the verification of the Requirement R1 risk assessment. The term unaffiliated means that the selected verifying entity cannot be a corporate affiliate (*i.e.,* the verifying or third party reviewer cannot be an entity that corporately controls, is controlled by or is under common control with, the Transmission Owner). The verifying entity also cannot be a division of the Transmission Owner that operates as a functional unit.

The prohibition on registered entities using a corporate affiliate to conduct the verification, however, does not prohibit a governmental entity (e.g., a city, a municipality, a U.S. federal power marketing agency, or any other political subdivision of U.S. or Canadian federal, state, or provincial governments) from selecting as the verifying entity another governmental entity within the same political subdivision. For instance, a U.S. federal power marketing agency may select as its verifier another U.S. federal agency to conduct its verification so long as the selected entity has transmission planning or analysis experience. Similarly, a Transmission Owner owned by a Canadian province can use a separate agency of that province to perform the verification. The verifying entity, however, must still be a third party and cannot be a division of the registered entity that operates as a functional unit.

Requirement R2 also provides that the "verification may occur concurrent with or after the risk assessment performed under Requirement R1." This provision is designed to provide the Transmission Owner the flexibility to work with the verifying entity throughout (*i.e.,* concurrent with) the risk assessment, which for some Transmission Owners may be more efficient and effective. In other words, a Transmission Owner could collaborate with their unaffiliated verifying entity to perform the risk assessment under Requirement R1 such that both Requirement R1 and Requirement R2 are satisfied concurrently. The intent of Requirement R2 is to have an entity other than the owner or operator of the facility to be involved in the risk

assessment process and have an opportunity to provide input. Accordingly, Requirement R2 is designed to allow entities the discretion to have a two-step process, where the Transmission Owner performs the risk assessment and subsequently has a third party review that assessment, or a one-step process, where the entity collaborates with a third party to perform the risk assessment.

Characteristics to consider in selecting a third party reviewer could include:

- Registered Entity with applicable planning and reliability functions.
- Experience in power system studies and planning.
- The entity's understanding of the MOD standards, TPL standards, and facility ratings as they pertain to planning studies.
- The entity's familiarity with the Interconnection within which the Transmission Owner is located.

With respect to the requirement that Transmission owners develop and implement procedures for protecting confidential and sensitive information, the Transmission Owner could have a method for identifying documents that require confidential treatment. One mechanism for protecting confidential or sensitive information is to prohibit removal of sensitive or confidential information from the Transmission Owner's site. Transmission Owners could include such a prohibition in a non-disclosure agreement with the verifying entity.

A Technical feasibility study is not required in the Requirement R2 documentation of the technical basis for not modifying the identification in accordance with the recommendation.

On the issue of the difference between a verifier in Requirement R2 and a reviewer in Requirement R6, the SDT indicates that the verifier will confirm that the risk assessment was completed in accordance with Requirement R1, including the number of Transmission stations and substations identified, while the reviewer in Requirement R6 is providing expertise on the manner in which the evaluation of threats was conducted in accordance with Requirement R4, and the physical security plan in accordance with Requirement R5. In the latter situation there is no verification of a technical analysis, rather an application of experience and expertise to provide guidance or recommendations, if needed.

Parts 2.4 and 6.4 require the entities to have procedures to protect the confidentiality of sensitive or confidential information. Those procedures may include the following elements:

1. Control and retention of information on site for third party verifiers/reviewers.
2. Only "need to know" employees, etc., get the information.
3. Marking documents as confidential
4. Securely storing and destroying information when no longer needed.
5. Not releasing information outside the entity without, for example, General Counsel sign-off.

Requirement R3

Some Transmission Operators will have obligations under this standard for certain primary control centers. Those obligations, however, are contingent upon a Transmission Owner first completing the risk assessment specified by Requirement R1 and the verification specified by Requirement R2. Requirement R3 is intended to ensure that a Transmission Operator that has operational control of a primary control center identified in Requirement R1 receive notice so that the Transmission Operator may fulfill the rest of the obligations required in Requirements R4 through R6. Since the timing obligations in Requirements R4 through R6 are based upon completion of Requirement R2, the Transmission Owner must also include within the notice the date of completion of Requirement R2. Similarly, the Transmission Owner must notify the Transmission Operator of any removals from identification that result from a subsequent risk assessment under Requirement R1 or as a result of the verification process under Requirement R2.

Requirement R4

This requirement requires owners and operators of facilities identified by the Requirement R1 risk assessment and that are verified under Requirement R2 to conduct an assessment of potential threats and vulnerabilities to those Transmission stations, Transmission substations, and primary control centers using a tailored evaluation process. Threats and vulnerabilities may vary from facility to facility based on any number of factors that include, but are not limited to, location, size, function, existing physical security protections, and attractiveness as a target.

In order to effectively conduct a threat and vulnerability assessment, the asset owner may be the best source to determine specific site vulnerabilities, but current and evolving threats may best be determined by others in the intelligence or law enforcement communities. A number of resources have been identified in the standard, but many others exist and asset owners are not limited to where they may turn for assistance. Additional resources may include state or local fusion centers, U.S. Department of Homeland Security, Federal Bureau of Investigations (FBI), Public Safety Canada, Royal Canadian Mounted Police, and InfraGard chapters coordinated by the FBI.

The Responsible Entity is required to take a number of factors into account in Parts 4.1 to 4.3 in order to make a risk-based evaluation under Requirement R4.

To assist in determining the current threat for a facility, the prior history of attacks on similarly protected facilities should be considered when assessing probability and likelihood of occurrence at the facility in question.

Resources that may be useful in conducting threat and vulnerability assessments include:

- NERC Security Guideline for the Electricity Sector: Physical Security.
- NERC Security Guideline: Physical Security Response.
- ASIS International General Risk Assessment Guidelines.
- ASIS International Facilities Physical Security Measure Guideline.

- ASIS International Security Management Standard: Physical Asset Protection.
- Whole Building Design Guide - Threat/Vulnerability Assessments.

Requirement R5

This requirement specifies development and implementation of a security plan(s) designed to protect against attacks to the facilities identified in Requirement R1 based on the assessment performed under Requirement R4.

Requirement R5 specifies the following attributes for the physical security plan:

- *Resiliency or security measures designed collectively to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R4.*

  Resiliency may include, among other things:

  a. System topology changes,

  b. Spare equipment,

  c. Construction of a new Transmission station or Transmission substation.

  While most security measures will work together to collectively harden the entire site, some may be allocated to protect specific critical components. For example, if protection from gunfire is considered necessary, the entity may only install ballistic protection for critical components, not the entire site.

- *Law enforcement contact and coordination information.*

  Examples of such information may be posting 9-1-1 for emergency calls and providing substation safety and familiarization training for local and federal law enforcement, fire department, and Emergency Medical Services.

- *A timeline for executing the physical security enhancements and modifications specified in the physical security plan.*

  Entities have the flexibility to prioritize the implementation of the various resiliency or security enhancements and modifications in their security plan according to risk, resources, or other factors. The requirement to include a timeline in the physical security plan for executing the actual physical security enhancements and modifications does not also require that the enhancements and modifications be completed within 120 days. The actual timeline may extend beyond the 120 days, depending on the amount of work to be completed.

- *Provisions to evaluate evolving physical threats, and their corresponding security measures, to the Transmission station(s), Transmission substation(s), or primary control center(s).*

  A registered entity's physical security plan should include processes and responsibilities for obtaining and handling alerts, intelligence, and threat warnings from various

sources. Some of these sources could include the ERO, ES-ISAC, and US and/or Canadian federal agencies. This information should be used to reevaluate or consider changes in the security plan and corresponding security measures of the security plan found in R5.

Incremental changes made to the physical security plan prior to the next required third party review do not require additional third party reviews.

Requirement R6

This requirement specifies review by an entity other than the Transmission Owner or Transmission Operator with appropriate expertise for the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5. As with Requirement R2, the term unaffiliated means that the selected third party reviewer cannot be a corporate affiliate (*i.e.,* the third party reviewer cannot be an entity that corporately controls, is controlled by or is under common control with, the Transmission Operator). A third party reviewer also cannot be a division of the Transmission Operator that operates as a functional unit.

As noted in the guidance for Requirement R2, the prohibition on registered entities using a corporate affiliate to conduct the review, however, does not prohibit a governmental entity from selecting as the third party reviewer another governmental entity within the same political subdivision. For instance, a city or municipality may use its local enforcement agency, so long as the local law enforcement agency satisfies the criteria in Requirement R6. The third party reviewer, however, must still be a third party and cannot be a division of the registered entity that operates as a functional unit.

The Responsible Entity can select from several possible entities to perform the review:

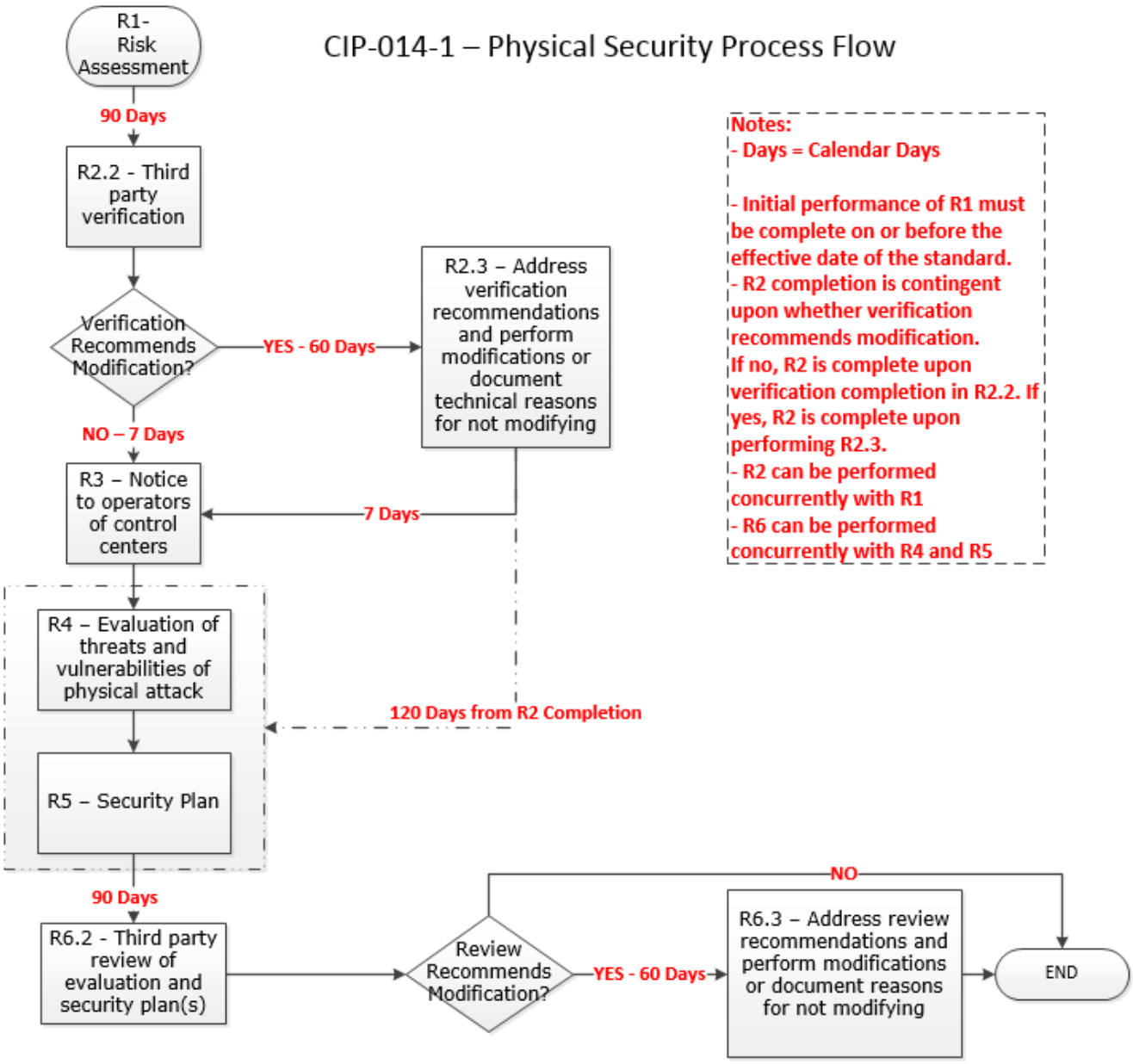
- *An entity or organization with electric industry physical security experience and whose review staff has at least one member who holds either a Certified Protection Professional (CPP) or Physical Security Professional (PSP) certification.*

  In selecting CPP and PSP for use in this standard, the SDT believed it was important that if a private entity such as a consulting or security firm was engaged to conduct the third party review, they must tangibly demonstrate competence to conduct the review. This includes electric industry physical security experience and either of the premier security industry certifications sponsored by ASIS International. The ASIS certification program was initiated in 1977, and those that hold the CPP certification are board certified in security management. Those that hold the PSP certification are board certified in physical security.

- *An entity or organization approved by the ERO.*
- *A governmental agency with physical security expertise.*
- *An entity or organization with demonstrated law enforcement, government, or military physical security expertise.*

As with the verification under Requirement R2, Requirement R6 provides that the "review may occur concurrently with or after completion of the evaluation performed under Requirement R4 and the security plan development under Requirement R5." This provision is designed to provide applicable Transmission Owners and Transmission Operators the flexibility to work with the third party reviewer throughout (*i.e.,* concurrent with) the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5, which for some Responsible Entities may be more efficient and effective. In other words, a Transmission Owner or Transmission Operator could collaborate with their unaffiliated third party reviewer to perform an evaluation of potential threats and vulnerabilities (Requirement R4) and develop a security plan (Requirement R5) to satisfy Requirements R4 through R6 simultaneously. The intent of Requirement R6 is to have an entity other than the owner or operator of the facility to be involved in the Requirement R4 evaluation and the development of the Requirement R5 security plans and have an opportunity to provide input on the evaluation and the security plan. Accordingly, Requirement R6 is designed to allow entities the discretion to have a two-step process, where the Transmission Owner performs the evaluation and develops the security plan itself and then has a third party review that assessment, or a one-step process, where the entity collaborates with a third party to perform the evaluation and develop the security plan.

Timeline


CIP-014-1 – Physical Security Process Flow
R1- Risk Assessment
90 Days
R2.2 - Third party verification
Verification Recommends Modification?
YES - 60 Days
R2.3 – Address verification recommendations and perform modifications or document technical reasons for not modifying
NO – 7 Days
R3 – Notice to operators of control centers
7 Days
R4 – Evaluation of threats and vulnerabilities of physical attack
120 Days from R2 Completion
R5 – Security Plan
90 Days
R6.2 - Third party review of evaluation and security plan(s)
Review Recommends Modification?
YES - 60 Days
R6.3 – Address review recommendations and perform modifications or document reasons for not modifying
NO
END
Notes:
- Days = Calendar Days
- Initial performance of R1 must be complete on or before the effective date of the standard.
- R2 completion is contingent upon whether verification recommends modification. If no, R2 is complete upon verification completion in R2.2. If yes, R2 is complete upon performing R2.3.
- R2 can be performed concurrently with R1
- R6 can be performed concurrently with R4 and R5

Rationale

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

Rationale for Requirement R1:
This requirement meets the FERC directive from paragraph 6 of its March 7, 2014 order on physical security to perform a risk assessment to identify which facilities if rendered inoperable or damaged could impact an Interconnection through instability, uncontrolled separation, or cascading failures. The requirement is not intended to bring within the scope of the standard a Transmission station or Transmission substation unless the applicable Transmission Owner determines through technical studies and analyses based on objective analysis, technical expertise, operating experience and experienced judgment that the loss of such facility would have a critical impact on the operation of the Interconnection in the event the asset is rendered inoperable or damaged. In the November 20, 2014 Order, FERC reiterated that "only an instability that has a "critical impact on the operation of the interconnection" warrants finding that the facility causing the instability is critical under Requirement R1." The Transmission Owner may determine the criteria for critical impact by considering, among other criteria, any of the following:

- Criteria or methodology used by Transmission Planners or Planning Coordinators in TPL-001-4, Requirement R6
- NERC EOP-004-2 reporting criteria
- Area or magnitude of potential impact

Requirement R1 also meets the FERC directive for periodic reevaluation of the risk assessment by requiring the risk assessment to be performed every 30 months (or 60 months for an entity that has not identified in a previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection).

After identifying each Transmission station and Transmission substation that meets the criteria in Requirement R1, it is important to additionally identify the primary control center that operationally controls that Transmission station or Transmission substation (*i.e.,* the control center whose electronic actions can cause direct physical actions at the identified Transmission station and Transmission substation, such as opening a breaker, compared to a control center that only has the ability to monitor the Transmission station and Transmission substation and, therefore, must coordinate direct physical action through another entity).

Rationale for Requirement R2:
This requirement meets the FERC directive from paragraph 11 in the order on physical security requiring verification by an entity other than the owner or operator of the risk assessment performed under Requirement R1.

This requirement provides the flexibility for a Transmission Owner to select registered and non-registered entities with transmission planning or analysis experience to perform the verification of the Requirement R1 risk assessment. The term "unaffiliated" means that the selected verifying entity cannot be a corporate affiliate (*i.e.*, the verifying entity cannot be an entity that controls, is controlled by, or is under common control with, the Transmission owner). The verifying entity also cannot be a division of the Transmission Owner that operates as a functional unit. The term "unaffiliated" is not intended to prohibit a governmental entity from using another government entity to be a verifier under Requirement R2.

Requirement R2 also provides the Transmission Owner the flexibility to work with the verifying entity throughout the Requirement R1 risk assessment, which for some Transmission Owners may be more efficient and effective. In other words, a Transmission Owner could coordinate with their unaffiliated verifying entity to perform a Requirement R1 risk assessment to satisfy both Requirement R1 and Requirement R2 concurrently.

Planning Coordinator is a functional entity listed in Part 2.1. The Planning Coordinator and Planning Authority are the same entity as shown in the NERC Glossary of Terms Used in NERC Reliability Standards.

Rationale for Requirement R3:
Some Transmission Operators will have obligations under this standard for certain primary control centers. Those obligations, however, are contingent upon a Transmission Owner first identifying which Transmission stations and Transmission substations meet the criteria specified by Requirement R1, as verified according to Requirement R2. This requirement is intended to ensure that a Transmission Operator that has operational control of a primary control center identified in Requirement R1, Part 1.2 of a Transmission station or Transmission substation verified according to Requirement R2 receives notice of such identification so that the Transmission Operator may timely fulfill its resulting obligations under Requirements R4 through R6. Since the timing obligations in Requirements R4 through R6 are based upon completion of Requirement R2, the Transmission Owner must also include notice of the date of completion of Requirement R2. Similarly, the Transmission Owner must notify the Transmission Operator of any removals from identification that result from a subsequent risk assessment under Requirement R1 or the verification process under Requirement R2.

Rationale for Requirement R4:
This requirement meets the FERC directive from paragraph 8 in the order on physical security that the reliability standard must require tailored evaluation of potential threats and vulnerabilities to facilities identified in Requirement R1 and verified according to Requirement R2. Threats and vulnerabilities may vary from facility to facility based on factors such as the facility's location, size, function, existing protections, and attractiveness of the target. As such, the requirement does not mandate a one-size-fits-all approach but requires entities to account for the unique characteristics of their facilities.

Requirement R4 does not explicitly state when the evaluation of threats and vulnerabilities must occur or be completed. However, Requirement R5 requires that the entity's security

plan(s), which is dependent on the Requirement R4 evaluation, must be completed within 120 calendar days following completion of Requirement R2. Thus, an entity has the flexibility when to complete the Requirement R4 evaluation, provided that it is completed in time to comply with the requirement in Requirement R5 to develop a physical security plan 120 calendar days following completion of Requirement R2.

Rationale for Requirement R5:
This requirement meets the FERC directive from paragraph 9 in the order on physical security requiring the development and implementation of a security plan(s) designed to protect against attacks to the facilities identified in Requirement R1 based on the assessment performed under Requirement R4.

Rationale for Requirement R6:
This requirement meets the FERC directive from paragraph 11 in the order on physical security requiring review by an entity other than the owner or operator with appropriate expertise of the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5.

As with the verification required by Requirement R2, Requirement R6 provides Transmission Owners and Transmission Operators the flexibility to work with the third party reviewer throughout the Requirement R4 evaluation and the development of the Requirement R5 security plan(s). This would allow entities to satisfy their obligations under Requirement R6 concurrent with the satisfaction of their obligations under Requirements R4 and R5.

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

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 initial ballot	August 2018 – September 2018
10-day final ballot	September 2018
NERC Board adoption	November 2018

Upon Board adoption, the rationale boxes will be moved to the Supplemental Material Section.

A. Introduction

1. Title: Physical Security

2. Number: CIP-014-3

3. Purpose: To identify and protect Transmission stations and Transmission substations, and their associated primary control centers, that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection.

4. Applicability:

4.1. Functional Entities:

4.1.1 Transmission Owner that owns a Transmission station or Transmission substation that meets any of the following criteria:

4.1.1.1 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.

4.1.1.2 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

4.1.1.3 Transmission Facilities at a single station or substation location that are identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation.

4.1.1.4 Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.

4.1.2 Transmission Operator.

Exemption: Facilities in a "protected area," as defined in 10 C.F.R. § 73.2, within the scope of a security plan approved or accepted by the Nuclear Regulatory Commission are not subject to this Standard; or, Facilities within the scope of a security plan approved or accepted by the Canadian Nuclear Safety Commission are not subject to this Standard.

5. Effective Dates:

See Implementation Plan for CIP-014-3.

6. Background:

Reliability Standard CIP-014-2 addresses the directives from the FERC order issued March 7, 2014, *Reliability Standards for Physical Security Measures*, 146 FERC ¶ 61,166 (2014), which required NERC to develop a physical security reliability standard(s) to identify and protect facilities that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection.

B. Requirements and Measures

R1. Each Transmission Owner shall perform an initial risk assessment and subsequent risk assessments of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria specified in Applicability Section 4.1.1. The initial and subsequent risk assessments shall consist of a transmission analysis or transmission analyses designed to identify the Transmission station(s) and Transmission substation(s) that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection. *[VRF: High; Time-Horizon: Long-term Planning]*

1.1. Subsequent risk assessments shall be performed:

- At least once every 30 calendar months for a Transmission Owner that has identified in its previous risk assessment (as verified according to Requirement R2) one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection; or

- At least once every 60 calendar months for a Transmission Owner that has not identified in its previous risk assessment (as verified according to Requirement R2) any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection.

1.2. The Transmission Owner shall identify the primary control center that operationally controls each Transmission station or Transmission substation identified in the Requirement R1 risk assessment.

M1. Examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation of the risk assessment of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria in Applicability Section 4.1.1 as specified in Requirement R1. Additionally, examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation of the identification of the primary control center that operationally controls each Transmission station or Transmission substation identified in the Requirement R1 risk assessment as specified in Requirement R1, Part 1.2.

R2. Each Transmission Owner shall have an unaffiliated third party verify the risk assessment performed under Requirement R1. The verification may occur concurrent with or after the risk assessment performed under Requirement R1. *[VRF: Medium; Time-Horizon: Long-term Planning]*

2.1. Each Transmission Owner shall select an unaffiliated verifying entity that is either:

- A registered Planning Coordinator, Transmission Planner, or Reliability Coordinator; or

- An entity that has transmission planning or analysis experience.

2.2. The unaffiliated third party verification shall verify the Transmission Owner's risk assessment performed under Requirement R1, which may include recommendations for the addition or deletion of a Transmission station(s) or Transmission substation(s). The Transmission Owner shall ensure the verification is completed within 90 calendar days following the completion of the Requirement R1 risk assessment.

2.3. If the unaffiliated verifying entity recommends that the Transmission Owner add a Transmission station(s) or Transmission substation(s) to, or remove a Transmission station(s) or Transmission substation(s) from, its identification under Requirement R1, the Transmission Owner shall either, within 60 calendar days of completion of the verification, for each recommended addition or removal of a Transmission station or Transmission substation:

- Modify its identification under Requirement R1 consistent with the recommendation; or

- Document the technical basis for not modifying the identification in accordance with the recommendation.

2.4. Each Transmission Owner shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party verifier and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.

M2. Examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation that the Transmission Owner completed an unaffiliated third party verification of the Requirement R1 risk assessment and satisfied all of the applicable provisions of Requirement R2, including, if applicable, documenting the technical basis for not modifying the Requirement R1 identification as specified under Part 2.3. Additionally, examples of evidence may include, but are not limited to, written or electronic documentation of procedures to protect information under Part 2.4.

R3. For a primary control center(s) identified by the Transmission Owner according to Requirement R1, Part 1.2 that a) operationally controls an identified Transmission station or Transmission substation verified according to Requirement R2, and b) is not under the operational control of the Transmission Owner: the Transmission Owner shall, within seven calendar days following completion of Requirement R2, notify the Transmission Operator that has operational control of the primary control center of

such identification and the date of completion of Requirement R2. *[VRF: Lower; Time-Horizon: Long-term Planning]*

3.1. If a Transmission station or Transmission substation previously identified under Requirement R1 and verified according to Requirement R2 is removed from the identification during a subsequent risk assessment performed according to Requirement R1 or a verification according to Requirement R2, then the Transmission Owner shall, within seven calendar days following the verification or the subsequent risk assessment, notify the Transmission Operator that has operational control of the primary control center of the removal.

M3. Examples of acceptable evidence may include, but are not limited to, dated written or electronic notifications or communications that the Transmission Owner notified each Transmission Operator, as applicable, according to Requirement R3.

R4. Each Transmission Owner that identified a Transmission station, Transmission substation, or a primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall conduct an evaluation of the potential threats and vulnerabilities of a physical attack to each of their respective Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2. The evaluation shall consider the following: *[VRF: Medium; Time-Horizon: Operations Planning, Long-term Planning]*

4.1. Unique characteristics of the identified and verified Transmission station(s), Transmission substation(s), and primary control center(s);

4.2. Prior history of attack on similar facilities taking into account the frequency, geographic proximity, and severity of past physical security related events; and

4.3. Intelligence or threat warnings received from sources such as law enforcement, the Electric Reliability Organization (ERO), the Electricity Sector Information Sharing and Analysis Center (ES-ISAC), U.S. federal and/or Canadian governmental agencies, or their successors.

M4. Examples of evidence may include, but are not limited to, dated written or electronic documentation that the Transmission Owner or Transmission Operator conducted an evaluation of the potential threats and vulnerabilities of a physical attack to their respective Transmission station(s), Transmission substation(s) and primary control center(s) as specified in Requirement R4.

R5. Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall develop and implement a documented physical security plan(s) that covers their respective Transmission station(s), Transmission substation(s), and primary control center(s). The physical security plan(s) shall be

developed within 120 calendar days following the completion of Requirement R2 and executed according to the timeline specified in the physical security plan(s). The physical security plan(s) shall include the following attributes: *[VRF: High; Time-Horizon: Long-term Planning]*

5.1. Resiliency or security measures designed collectively to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R4.

5.2. Law enforcement contact and coordination information.

5.3. A timeline for executing the physical security enhancements and modifications specified in the physical security plan.

5.4. Provisions to evaluate evolving physical threats, and their corresponding security measures, to the Transmission station(s), Transmission substation(s), or primary control center(s).

M5. Examples of evidence may include, but are not limited to, dated written or electronic documentation of its physical security plan(s) that covers their respective identified and verified Transmission station(s), Transmission substation(s), and primary control center(s) as specified in Requirement R5, and additional evidence demonstrating execution of the physical security plan according to the timeline specified in the physical security plan.

R6. Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall have an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5. The review may occur concurrently with or after completion of the evaluation performed under Requirement R4 and the security plan development under Requirement R5. *[VRF: Medium; Time-Horizon: Long-term Planning]*

6.1. Each Transmission Owner and Transmission Operator shall select an unaffiliated third party reviewer from the following:

- An entity or organization with electric industry physical security experience and whose review staff has at least one member who holds either a Certified Protection Professional (CPP) or Physical Security Professional (PSP) certification.
- An entity or organization approved by the ERO.
- A governmental agency with physical security expertise.

- An entity or organization with demonstrated law enforcement, government, or military physical security expertise.

6.2. The Transmission Owner or Transmission Operator, respectively, shall ensure that the unaffiliated third party review is completed within 90 calendar days of completing the security plan(s) developed in Requirement R5. The unaffiliated third party review may, but is not required to, include recommended changes to the evaluation performed under Requirement R4 or the security plan(s) developed under Requirement R5.

6.3. If the unaffiliated third party reviewer recommends changes to the evaluation performed under Requirement R4 or security plan(s) developed under Requirement R5, the Transmission Owner or Transmission Operator shall, within 60 calendar days of the completion of the unaffiliated third party review, for each recommendation:

- Modify its evaluation or security plan(s) consistent with the recommendation; or

- Document the reason(s) for not modifying the evaluation or security plan(s) consistent with the recommendation.

6.4. Each Transmission Owner and Transmission Operator shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party reviewer and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.

M6. Examples of evidence may include, but are not limited to, written or electronic documentation that the Transmission Owner or Transmission Operator had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 as specified in Requirement R6 including, if applicable, documenting the reasons for not modifying the evaluation or security plan(s) in accordance with a recommendation under Part 6.3. Additionally, examples of evidence may include, but are not limited to, written or electronic documentation of procedures to protect information under Part 6.4.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence during an on-site visit to show that it was compliant for the full time period since the last audit.

The Transmission Owner and Transmission Operator shall keep data or evidence to show compliance, as identified below, unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation.

The responsible entities shall retain documentation as evidence for three years.

If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records, subject to the confidentiality provisions of Section 1500 of the Rules of Procedure and the provisions of Section 1.4 below.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints Text

1.4. Additional Compliance Information

Confidentiality: To protect the confidentiality and sensitive nature of the evidence for demonstrating compliance with this standard, all evidence will be retained at the Transmission Owner’s and Transmission Operator’s facilities.

2. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Long-term Planning**	**High**	The Transmission Owner performed an initial risk assessment but did so after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to two calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could	The Transmission Owner performed an initial risk assessment but did so more than two calendar months after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to four calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable	The Transmission Owner performed an initial risk assessment but did so more than four calendar months after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to six calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could	The Transmission Owner performed an initial risk assessment but did so more than six calendar months after the date specified in the implementation plan for performing the initial risk assessment; OR The Transmission Owner failed to perform an initial risk assessment; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 30 calendar months but less than or equal to 32 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an	or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 32 calendar months but less than or equal to 34 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an	result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 34 calendar months but less than or equal to 36 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection	stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after more than 36 calendar months; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability,

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Interconnection performed a subsequent risk assessment but did so after 60 calendar months but less than or equal to 62 calendar months.	Interconnection performed a subsequent risk assessment but did so after 62 calendar months but less than or equal to 64 calendar months.	performed a subsequent risk assessment but did so after 64 calendar months but less than or equal to 66 calendar months; OR The Transmission Owner performed a risk assessment but failed to include Part 1.2.	uncontrolled separation, or Cascading within an Interconnection failed to perform a risk assessment; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after more than 66 calendar months;

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						OR The Transmission Owner that has not identified in its previous risk assessment any Transmission station and Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection failed to perform a subsequent risk assessment.
R2	**Long-term Planning**	**Medium**	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so in more than 90 calendar days but	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 100 calendar days but	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 110 calendar days but less than or equal to	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 120 calendar days

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			less than or equal to 100 calendar days following completion of Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part 2.3 but did so more than 60 calendar days and less than or equal to 70 calendar days from completion of the third party verification.	less than or equal to 110 calendar days following completion of Requirement R1; Or The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part 2.3 but did so more than 70 calendar days and less than or equal to 80 calendar days from completion of the third party verification.	120 calendar days following completion of Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part 2.3 but did so more than 80 calendar days from completion of the third party verification; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed	following completion of Requirement R1; OR The Transmission Owner failed to have an unaffiliated third party verify the risk assessment performed under Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but failed to implement procedures for protecting information per Part 2.4.

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					under Requirement R1 but failed to modify or document the technical basis for not modifying its identification under R1 as required by Part 2.3.	
R3	**Long-term Planning**	**Lower**	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than seven calendar days and less than or equal to nine calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than nine calendar days and less than or equal to 11 calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than 11 calendar days and less than or equal to 13 calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that operates the primary control center	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than 13 calendar days following the completion of Requirement R2; OR The Transmission Owner failed to notify the Transmission Operator that it operates a control

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			operates the primary control center of the removal from the identification in Requirement R1 but did so more than seven calendar days and less than or equal to nine calendar days following the verification or the subsequent risk assessment.	operates the primary control center of the removal from the identification in Requirement R1 but did so more than nine calendar days and less than or equal to 11 calendar days following the verification or the subsequent risk assessment.	of the removal from the identification in Requirement R1 but did so more than 11 calendar days and less than or equal to 13 calendar days following the verification or the subsequent risk assessment.	center identified in Requirement R1; OR The Transmission Owner notified the Transmission Operator that operates the primary control center of the removal from the identification in Requirement R1 but did so more than 13 calendar days following the verification or the subsequent risk assessment. OR The Transmission Owner failed to notify the Transmission Operator that operates the primary control center of the removal from the

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						identification in Requirement R1.
R4	**Operations Planning, Long-term Planning**	**Medium**	N/A	The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but failed to consider one of Parts 4.1 through 4.3 in the evaluation.	The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but failed to consider two of Parts 4.1 through 4.3 in the evaluation.	The Responsible Entity failed to conduct an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1; OR The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						substation(s), and primary control center(s) identified in Requirement R1 but failed to consider Parts 4.1 through 4.3.
R5	**Long-term Planning**	**High**	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 120 calendar days but less than or equal to 130 calendar days after completing Requirement R2; OR	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 130 calendar days but less than or equal to 140 calendar days after completing Requirement R2; OR	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 140 calendar days but less than or equal to 150 calendar days after completing Requirement R2; OR	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 150 calendar days after completing the verification in Requirement R2; OR

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include one of Parts 5.1 through 5.4 in the plan.	The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include two of Parts 5.1 through 5.4 in the plan.	The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include three of Parts 5.1 through 5.4 in the plan.	The Responsible Entity failed to develop and implement a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2. OR The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						primary control center(s) identified in Requirement R1 and verified according to Requirement 2 but failed to include Parts 5.1 through 5.4 in the plan.
R6	**Long-term Planning**	**Medium**	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so in more than 90 calendar days but less than or equal to 100 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so in more than 100 calendar days but less than or equal to 110 calendar days; OR The Responsible Entity had an unaffiliated third party review the	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so more than 110 calendar days but less than or equal to 120 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security	The Responsible Entity failed to have an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 in more than 120 calendar days; OR The Responsible Entity failed to have an unaffiliated third party review the evaluation performed under

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			under Requirement R4 and the security plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 60 calendar days and less than or equal to 70 calendar days following completion of the third party review.	evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 70 calendar days and less than or equal to 80 calendar days following completion of the third party review.	plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 80 calendar days following completion of the third party review; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did not document the reason for not modifying the security plan(s) as specified in Part 6.3.	Requirement R4 and the security plan(s) developed under Requirement R5; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but failed to implement procedures for protecting information per Part 6.4.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	October 1, 2015	Effective Date	New
2	April 16, 2015	Revised to meet FERC Order 802 directive to remove “widespread”.	Revision
2	May 7, 2015	Adopted by the NERC Board of Trustees	
2	July 14, 2015	FERC Letter Order in Docket No. RD15-4-000 approving CIP-014-2	

Guidelines and Technical Basis

Section 4 Applicability

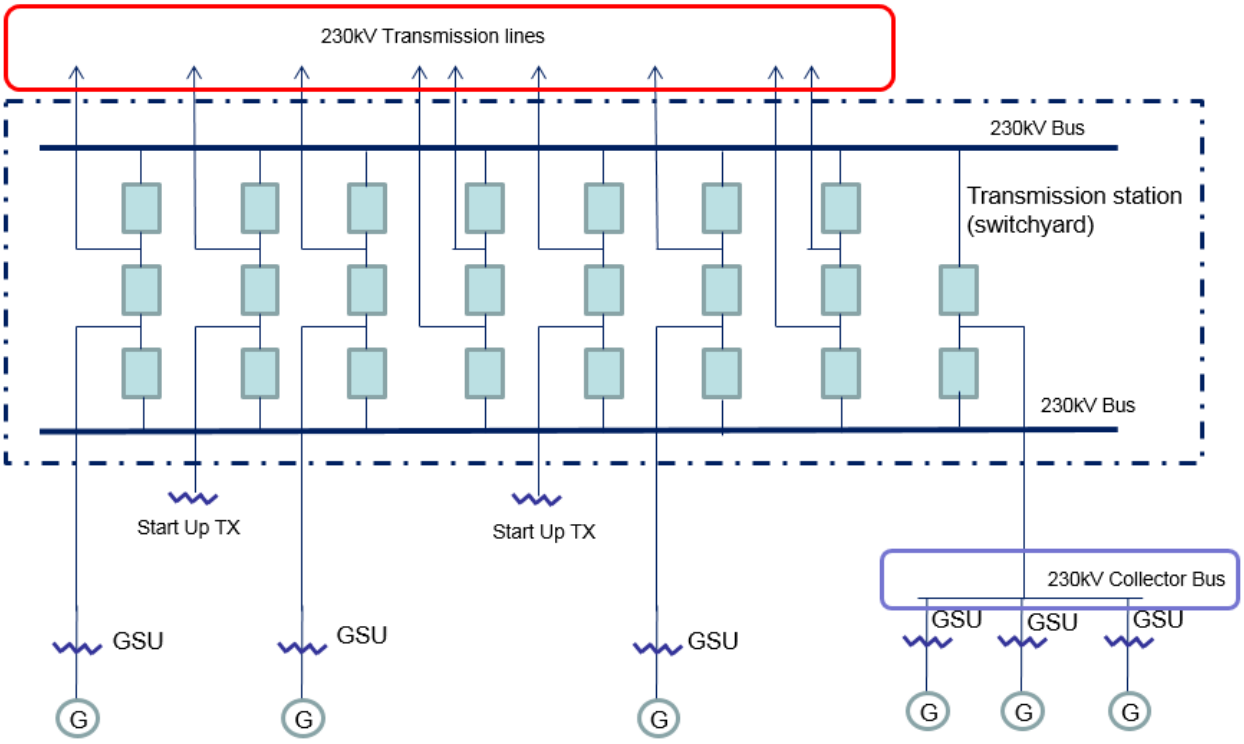
The purpose of Reliability Standard CIP-014 is to protect Transmission stations and Transmission substations, and their associated primary control centers that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. To properly include those entities that own or operate such Facilities, the Reliability Standard CIP-014 first applies to Transmission Owners that own Transmission Facilities that meet the specific criteria in Applicability Section 4.1.1.1 through 4.1.1.4. The Facilities described in Applicability Section 4.1.1.1 through 4.1.1.4 mirror those Transmission Facilities that meet the bright line criteria for "Medium Impact" Transmission Facilities under Attachment 1 of Reliability Standard CIP-002-5.1. Each Transmission Owner that owns Transmission Facilities that meet the criteria in Section 4.1.1.1 through 4.1.1.4 is required to perform a risk assessment as specified in Requirement R1 to identify its Transmission stations and Transmission substations, and their associated primary control centers, that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. The Standard Drafting Team (SDT) expects this population will be small and that many Transmission Owners that meet the applicability of this standard will not actually identify any such Facilities. Only those Transmission Owners with Transmission stations or Transmission substations identified in the risk assessment (and verified under Requirement R2) have performance obligations under Requirements R3 through R6.

This standard also applies to Transmission Operators. A Transmission Operator's obligations under the standard, however, are only triggered if the Transmission Operator is notified by an applicable Transmission Owner under Requirement R3 that the Transmission Operator operates a primary control center that operationally controls a Transmission station(s) or Transmission substation(s) identified in the Requirement R1 risk assessment. A primary control center operationally controls a Transmission station or Transmission substation when the control center's electronic actions can cause direct physical action at the identified Transmission station or Transmission substation, such as opening a breaker, as opposed to a control center that only has information from the Transmission station or Transmission substation and must coordinate direct action through another entity. Only Transmission Operators who are notified that they have primary control centers under this standard have performance obligations under Requirements R4 through R6. In other words, primary control center for purposes of this Standard is the control center that the Transmission Owner or Transmission Operator, respectively, uses as its primary, permanently-manned site to physically operate a Transmission station or Transmission substation that is identified in Requirement R1 and verified in Requirement R2. Control centers that provide back-up capability are not applicable, as they are a form of resiliency and intentionally redundant.

The SDT considered several options for bright line criteria that could be used to determine applicability and provide an initial threshold that defines the set of Transmission stations and Transmission substations that would meet the directives of the FERC order on physical security (*i.e.*, those that could cause instability, uncontrolled separation, or Cascading within an

Interconnection). The SDT determined that using the criteria for Medium Impact Transmission Facilities in Attachment 1 of CIP-002-5.1 would provide a conservative threshold for defining which Transmission stations and Transmission substations must be included in the risk assessment in Requirement R1 of CIP-014. Additionally, the SDT concluded that using the CIP-002-5.1 Medium Impact criteria was appropriate because it has been approved by stakeholders, NERC, and FERC, and its use provides a technically sound basis to determine which Transmission Owners should conduct the risk assessment. As described in CIP-002-5.1, the failure of a Transmission station or Transmission substation that meets the Medium Impact criteria could have the capability to result in instability, uncontrolled separation, or Cascading. The SDT understands that using this bright line criteria to determine applicability may require some Transmission Owners to perform risk assessments under Requirement R1 that will result in a finding that none of their Transmission stations or Transmission substations would pose a risk of instability, uncontrolled separation, or Cascading within an Interconnection. However, the SDT determined that higher bright lines could not be technically justified to ensure inclusion of all Transmission stations and Transmission substations, and their associated primary control centers that, if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. Further guidance and technical basis for the bright line criteria for Medium Impact Facilities can be found in the Guidelines and Technical Basis section of CIP-002-5.1.

Additionally, the SDT determined that it was not necessary to include Generator Operators and Generator Owners in the Reliability Standard. First, Transmission stations or Transmission substations interconnecting generation facilities are considered when determining applicability. Transmission Owners will consider those Transmission stations and Transmission substations that include a Transmission station on the high side of the Generator Step-up transformer (GSU) using Applicability Section 4.1.1.1 and 4.1.1.2. As an example, a Transmission station or Transmission substation identified as a Transmission Owner facility that interconnects generation will be subject to the Requirement R1 risk assessment if it operates at 500kV or greater or if it is connected at 200 kV – 499kV to three or more other Transmission stations or Transmission substations and has an "aggregate weighted value" exceeding 3000 according to the table in Applicability Section 4.1.1.2. Second, the Transmission analysis or analyses conducted under Requirement R1 should take into account the impact of the loss of generation connected to applicable Transmission stations or Transmission substations. Additionally, the FERC order does not explicitly mention generation assets and is reasonably understood to focus on the most critical Transmission Facilities. The diagram below shows an example of a station.



Also, the SDT uses the phrase "Transmission stations or Transmission 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 (switching stations or switchyards). Therefore, the SDT chose to use both "station" and "substation" to refer to the locations where groups of Transmission Facilities exist.

On the issue of joint ownership, the SDT recognizes that this issue is not unique to CIP-014, and expects that the applicable Transmission Owners and Transmission Operators will develop memorandums of understanding, agreements, Coordinated Functional Registrations, or procedures, etc., to designate responsibilities under CIP-014 when joint ownership is at issue, which is similar to what many entities have completed for other Reliability Standards.

The language contained in the applicability section regarding the collector bus is directly copied from CIP-002-5.1, Attachment 1, and has no additional meaning within the CIP-014 standard.

Requirement R1

The initial risk assessment required under Requirement R1 must be completed on or before the effective date of the standard. Subsequent risk assessments are to be performed at least once every 30 or 60 months depending on the results of the previous risk assessment per Requirement R1, Part 1.1. In performing the risk assessment under Requirement R1, the

Transmission Owner should first identify their population of Transmission stations and Transmission substations that meet the criteria contained in Applicability Section 4.1.1. Requirement R1 then requires the Transmission Owner to perform a risk assessment, consisting of a transmission analysis, to determine which of those Transmission stations and Transmission Substations if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection. The requirement is not to require identification of, and thus, not intended to bring within the scope of the standard a Transmission station or Transmission substation unless the applicable Transmission Owner determines through technical studies and analyses based on objective analysis, technical expertise, operating experience and experienced judgment that the loss of such facility would have a critical impact on the operation of the Interconnection in the event the asset is rendered inoperable or damaged. In the November 20, 2014 Order, FERC reiterated that "only an instability that has a "critical impact on the operation of the interconnection" warrants finding that the facility causing the instability is critical under Requirement R1." The Transmission Owner may determine the criteria for critical impact by considering, among other criteria, any of the following:

- Criteria or methodology used by Transmission Planners or Planning Coordinators in TPL-001-4, Requirement R6
- NERC EOP-004-2 reporting criteria
- Area or magnitude of potential impact

The standard does not mandate the specific analytical method for performing the risk assessment. The Transmission Owner has the discretion to choose the specific method that best suites its needs. As an example, an entity may perform a Power Flow analysis and stability analysis at a variety of load levels.

Performing Risk Assessments

The Transmission Owner has the discretion to select a transmission analysis method that fits its facts and system circumstances. To mandate a specific approach is not technically desirable and may lead to results that fail to adequately consider regional, topological, and system circumstances. The following guidance is only an example on how a Transmission Owner may perform a power flow and/or stability analysis to identify those Transmission stations and Transmission substations that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. An entity could remove all lines, without regard to the voltage level, to a single Transmission station or Transmission substation and review the simulation results to assess system behavior to determine if Cascading of Transmission Facilities, uncontrolled separation, or voltage or frequency instability is likely to occur over a significant area of the Interconnection. Using engineering judgment, the Transmission Owner (possibly in consultation with regional planning or operation committees and/or ISO/RTO committee input) should develop criteria (e.g. imposing a fault near the removed Transmission station or Transmission substation) to identify a contingency or parameters that result in potential instability, uncontrolled separation, or Cascading within an Interconnection. Regional consultation on these matters is likely to be

helpful and informative, given that the inputs for the risk assessment and the attributes of what constitutes instability, uncontrolled separation, or Cascading within an Interconnection will likely vary from region-to-region or from ISO-to-ISO based on topology, system characteristics, and system configurations. Criteria could also include post-contingency facilities loadings above a certain emergency rating or failure of a power flow case to converge. Available special protection systems (SPS), if any, could be applied to determine if the system experiences any additional instability which may result in uncontrolled separation. Example criteria may include:

(a) Thermal overloads beyond facility emergency ratings;

(b) Voltage deviation exceeding ± 10%; or

(c) Cascading outage/voltage collapse; or

(d) Frequency below under-frequency load shed points

Periodicity

A Transmission Owner who identifies one or more Transmission stations or Transmission substations (as verified under Requirement R2) that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection is required to conduct a risk assessment at least once every 30 months. This period ensures that the risk assessment remains current with projected conditions and configurations in the planned system. This risk assessment, as the initial assessment, must consider applicable planned Transmission stations and Transmission substations to be in service within 24 months. The 30 month timeframe aligns with the 24 month planned to be in service date because the Transmission Owner is provided the flexibility, depending on its planning cycle and the frequency in which it may plan to construct a new Transmission station or Transmission substation to more closely align these dates. The requirement is to conduct the risk assessment at least once every 30 months, so for a Transmission Owner that believes it is better to conduct a risk assessment once every 24 months, because of its planning cycle, it has the flexibility to do so.

Transmission Owners that have not identified any Transmission stations or Transmission substations (as verified under Requirement R2) that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection are unlikely to see changes to their risk assessment in the Near-Term Planning Horizon. Consequently, a 60 month periodicity for completing a subsequent risk assessment is specified.

Identification of Primary Control Centers

After completing the risk assessment specified in Requirement R1, it is important to additionally identify the primary control center that operationally controls each Transmission station or Transmission substation that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection. A primary control center “operationally controls” a Transmission station or Transmission substation when the control

center's electronic actions can cause direct physical actions at the identified Transmission station and Transmission substation, such as opening a breaker.

Requirement R2

This requirement specifies verification of the risk assessment performed under Requirement R1 by an entity other than the owner or operator of the Requirement R1 risk assessment.

A verification of the risk assessment by an unaffiliated third party, as specified in Requirement R2, could consist of:

1. Certifying that the Requirement R1 risk assessment considers the Transmission stations and Transmission substations identified in Applicability Section 4.1.1.
2. Review of the model used to conduct the risk assessment to ensure it contains sufficient system topology to identify Transmission stations and Transmission substations that if rendered inoperable or damaged could cause instability, uncontrolled separation, or Cascading within an Interconnection.
3. Review of the Requirement R1 risk assessment methodology.

This requirement provides the flexibility for a Transmission Owner to select from unaffiliated registered and non-registered entities with transmission planning or analysis experience to perform the verification of the Requirement R1 risk assessment. The term unaffiliated means that the selected verifying entity cannot be a corporate affiliate (*i.e.,* the verifying or third party reviewer cannot be an entity that corporately controls, is controlled by or is under common control with, the Transmission Owner). The verifying entity also cannot be a division of the Transmission Owner that operates as a functional unit.

The prohibition on registered entities using a corporate affiliate to conduct the verification, however, does not prohibit a governmental entity (e.g., a city, a municipality, a U.S. federal power marketing agency, or any other political subdivision of U.S. or Canadian federal, state, or provincial governments) from selecting as the verifying entity another governmental entity within the same political subdivision. For instance, a U.S. federal power marketing agency may select as its verifier another U.S. federal agency to conduct its verification so long as the selected entity has transmission planning or analysis experience. Similarly, a Transmission Owner owned by a Canadian province can use a separate agency of that province to perform the verification. The verifying entity, however, must still be a third party and cannot be a division of the registered entity that operates as a functional unit.

Requirement R2 also provides that the "verification may occur concurrent with or after the risk assessment performed under Requirement R1." This provision is designed to provide the Transmission Owner the flexibility to work with the verifying entity throughout (*i.e.,* concurrent with) the risk assessment, which for some Transmission Owners may be more efficient and effective. In other words, a Transmission Owner could collaborate with their unaffiliated verifying entity to perform the risk assessment under Requirement R1 such that both Requirement R1 and Requirement R2 are satisfied concurrently. The intent of Requirement R2 is to have an entity other than the owner or operator of the facility to be involved in the risk

assessment process and have an opportunity to provide input. Accordingly, Requirement R2 is designed to allow entities the discretion to have a two-step process, where the Transmission Owner performs the risk assessment and subsequently has a third party review that assessment, or a one-step process, where the entity collaborates with a third party to perform the risk assessment.

Characteristics to consider in selecting a third party reviewer could include:

- Registered Entity with applicable planning and reliability functions.
- Experience in power system studies and planning.
- The entity's understanding of the MOD standards, TPL standards, and facility ratings as they pertain to planning studies.
- The entity's familiarity with the Interconnection within which the Transmission Owner is located.

With respect to the requirement that Transmission owners develop and implement procedures for protecting confidential and sensitive information, the Transmission Owner could have a method for identifying documents that require confidential treatment. One mechanism for protecting confidential or sensitive information is to prohibit removal of sensitive or confidential information from the Transmission Owner's site. Transmission Owners could include such a prohibition in a non-disclosure agreement with the verifying entity.

A Technical feasibility study is not required in the Requirement R2 documentation of the technical basis for not modifying the identification in accordance with the recommendation.

On the issue of the difference between a verifier in Requirement R2 and a reviewer in Requirement R6, the SDT indicates that the verifier will confirm that the risk assessment was completed in accordance with Requirement R1, including the number of Transmission stations and substations identified, while the reviewer in Requirement R6 is providing expertise on the manner in which the evaluation of threats was conducted in accordance with Requirement R4, and the physical security plan in accordance with Requirement R5. In the latter situation there is no verification of a technical analysis, rather an application of experience and expertise to provide guidance or recommendations, if needed.

Parts 2.4 and 6.4 require the entities to have procedures to protect the confidentiality of sensitive or confidential information. Those procedures may include the following elements:

1. Control and retention of information on site for third party verifiers/reviewers.
2. Only "need to know" employees, etc., get the information.
3. Marking documents as confidential
4. Securely storing and destroying information when no longer needed.
5. Not releasing information outside the entity without, for example, General Counsel sign-off.

Requirement R3

Some Transmission Operators will have obligations under this standard for certain primary control centers. Those obligations, however, are contingent upon a Transmission Owner first completing the risk assessment specified by Requirement R1 and the verification specified by Requirement R2. Requirement R3 is intended to ensure that a Transmission Operator that has operational control of a primary control center identified in Requirement R1 receive notice so that the Transmission Operator may fulfill the rest of the obligations required in Requirements R4 through R6. Since the timing obligations in Requirements R4 through R6 are based upon completion of Requirement R2, the Transmission Owner must also include within the notice the date of completion of Requirement R2. Similarly, the Transmission Owner must notify the Transmission Operator of any removals from identification that result from a subsequent risk assessment under Requirement R1 or as a result of the verification process under Requirement R2.

Requirement R4

This requirement requires owners and operators of facilities identified by the Requirement R1 risk assessment and that are verified under Requirement R2 to conduct an assessment of potential threats and vulnerabilities to those Transmission stations, Transmission substations, and primary control centers using a tailored evaluation process. Threats and vulnerabilities may vary from facility to facility based on any number of factors that include, but are not limited to, location, size, function, existing physical security protections, and attractiveness as a target.

In order to effectively conduct a threat and vulnerability assessment, the asset owner may be the best source to determine specific site vulnerabilities, but current and evolving threats may best be determined by others in the intelligence or law enforcement communities. A number of resources have been identified in the standard, but many others exist and asset owners are not limited to where they may turn for assistance. Additional resources may include state or local fusion centers, U.S. Department of Homeland Security, Federal Bureau of Investigations (FBI), Public Safety Canada, Royal Canadian Mounted Police, and InfraGard chapters coordinated by the FBI.

The Responsible Entity is required to take a number of factors into account in Parts 4.1 to 4.3 in order to make a risk-based evaluation under Requirement R4.

To assist in determining the current threat for a facility, the prior history of attacks on similarly protected facilities should be considered when assessing probability and likelihood of occurrence at the facility in question.

Resources that may be useful in conducting threat and vulnerability assessments include:

- NERC Security Guideline for the Electricity Sector: Physical Security.
- NERC Security Guideline: Physical Security Response.
- ASIS International General Risk Assessment Guidelines.
- ASIS International Facilities Physical Security Measure Guideline.

- ASIS International Security Management Standard: Physical Asset Protection.
- Whole Building Design Guide - Threat/Vulnerability Assessments.

Requirement R5

This requirement specifies development and implementation of a security plan(s) designed to protect against attacks to the facilities identified in Requirement R1 based on the assessment performed under Requirement R4.

Requirement R5 specifies the following attributes for the physical security plan:

- *Resiliency or security measures designed collectively to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R4.*

  Resiliency may include, among other things:

  a. System topology changes,

  b. Spare equipment,

  c. Construction of a new Transmission station or Transmission substation.

  While most security measures will work together to collectively harden the entire site, some may be allocated to protect specific critical components. For example, if protection from gunfire is considered necessary, the entity may only install ballistic protection for critical components, not the entire site.

- *Law enforcement contact and coordination information.*

  Examples of such information may be posting 9-1-1 for emergency calls and providing substation safety and familiarization training for local and federal law enforcement, fire department, and Emergency Medical Services.

- *A timeline for executing the physical security enhancements and modifications specified in the physical security plan.*

  Entities have the flexibility to prioritize the implementation of the various resiliency or security enhancements and modifications in their security plan according to risk, resources, or other factors. The requirement to include a timeline in the physical security plan for executing the actual physical security enhancements and modifications does not also require that the enhancements and modifications be completed within 120 days. The actual timeline may extend beyond the 120 days, depending on the amount of work to be completed.

- *Provisions to evaluate evolving physical threats, and their corresponding security measures, to the Transmission station(s), Transmission substation(s), or primary control center(s).*

  A registered entity's physical security plan should include processes and responsibilities for obtaining and handling alerts, intelligence, and threat warnings from various

sources. Some of these sources could include the ERO, ES-ISAC, and US and/or Canadian federal agencies. This information should be used to reevaluate or consider changes in the security plan and corresponding security measures of the security plan found in R5.

Incremental changes made to the physical security plan prior to the next required third party review do not require additional third party reviews.

Requirement R6

This requirement specifies review by an entity other than the Transmission Owner or Transmission Operator with appropriate expertise for the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5. As with Requirement R2, the term unaffiliated means that the selected third party reviewer cannot be a corporate affiliate (*i.e.,* the third party reviewer cannot be an entity that corporately controls, is controlled by or is under common control with, the Transmission Operator). A third party reviewer also cannot be a division of the Transmission Operator that operates as a functional unit.

As noted in the guidance for Requirement R2, the prohibition on registered entities using a corporate affiliate to conduct the review, however, does not prohibit a governmental entity from selecting as the third party reviewer another governmental entity within the same political subdivision. For instance, a city or municipality may use its local enforcement agency, so long as the local law enforcement agency satisfies the criteria in Requirement R6. The third party reviewer, however, must still be a third party and cannot be a division of the registered entity that operates as a functional unit.

The Responsible Entity can select from several possible entities to perform the review:

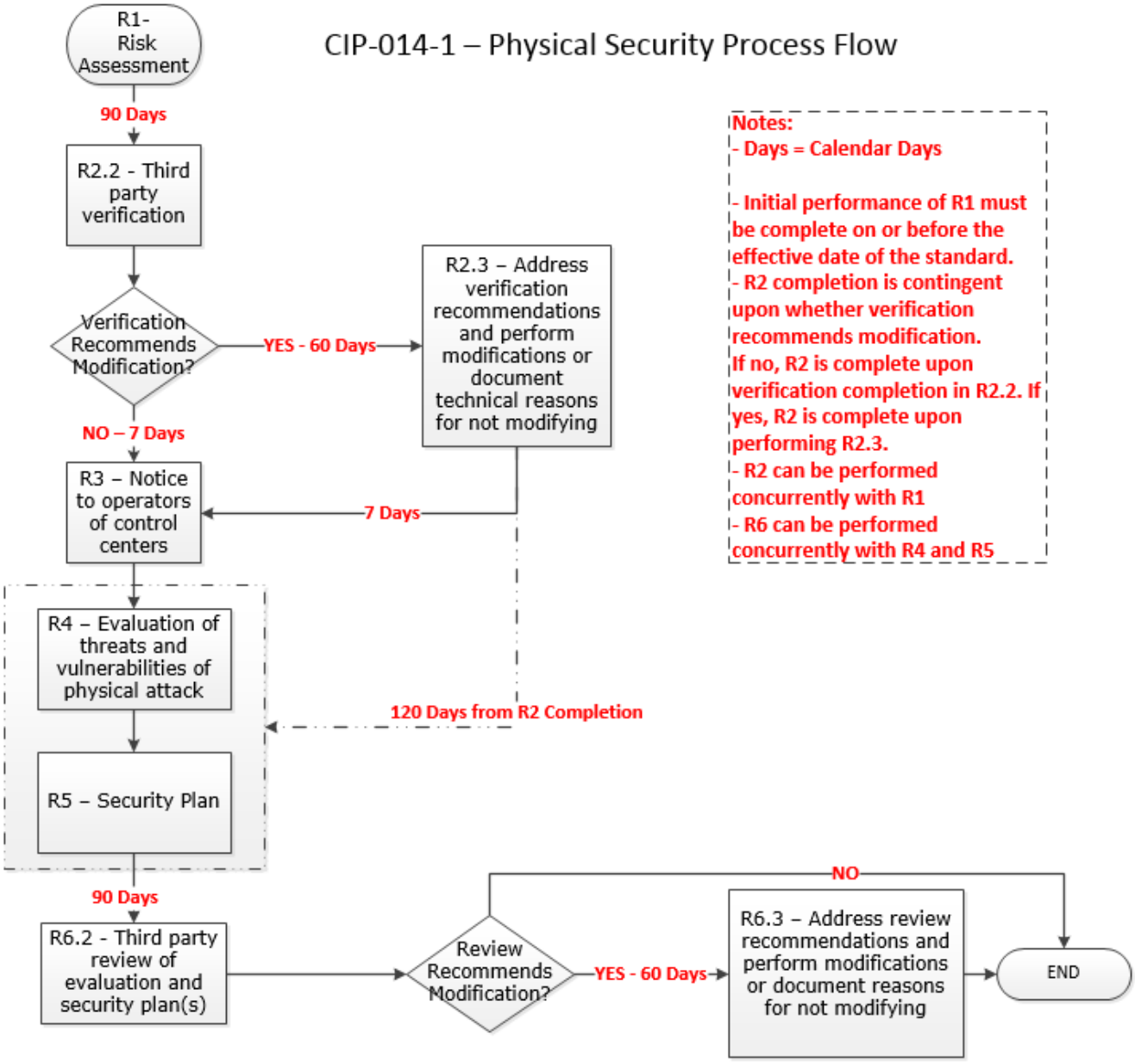
- *An entity or organization with electric industry physical security experience and whose review staff has at least one member who holds either a Certified Protection Professional (CPP) or Physical Security Professional (PSP) certification.*

  In selecting CPP and PSP for use in this standard, the SDT believed it was important that if a private entity such as a consulting or security firm was engaged to conduct the third party review, they must tangibly demonstrate competence to conduct the review. This includes electric industry physical security experience and either of the premier security industry certifications sponsored by ASIS International. The ASIS certification program was initiated in 1977, and those that hold the CPP certification are board certified in security management. Those that hold the PSP certification are board certified in physical security.

- *An entity or organization approved by the ERO.*
- *A governmental agency with physical security expertise.*
- *An entity or organization with demonstrated law enforcement, government, or military physical security expertise.*

As with the verification under Requirement R2, Requirement R6 provides that the "review may occur concurrently with or after completion of the evaluation performed under Requirement R4 and the security plan development under Requirement R5." This provision is designed to provide applicable Transmission Owners and Transmission Operators the flexibility to work with the third party reviewer throughout (*i.e.,* concurrent with) the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5, which for some Responsible Entities may be more efficient and effective. In other words, a Transmission Owner or Transmission Operator could collaborate with their unaffiliated third party reviewer to perform an evaluation of potential threats and vulnerabilities (Requirement R4) and develop a security plan (Requirement R5) to satisfy Requirements R4 through R6 simultaneously. The intent of Requirement R6 is to have an entity other than the owner or operator of the facility to be involved in the Requirement R4 evaluation and the development of the Requirement R5 security plans and have an opportunity to provide input on the evaluation and the security plan. Accordingly, Requirement R6 is designed to allow entities the discretion to have a two-step process, where the Transmission Owner performs the evaluation and develops the security plan itself and then has a third party review that assessment, or a one-step process, where the entity collaborates with a third party to perform the evaluation and develop the security plan.

Timeline


CIP-014-1 – Physical Security Process Flow
R1- Risk Assessment
90 Days
R2.2 - Third party verification
Verification Recommends Modification?
YES - 60 Days
R2.3 – Address verification recommendations and perform modifications or document technical reasons for not modifying
NO – 7 Days
7 Days
R3 – Notice to operators of control centers
R4 – Evaluation of threats and vulnerabilities of physical attack
120 Days from R2 Completion
R5 – Security Plan
90 Days
R6.2 - Third party review of evaluation and security plan(s)
Review Recommends Modification?
YES - 60 Days
NO
R6.3 – Address review recommendations and perform modifications or document reasons for not modifying
END
Notes:
- Days = Calendar Days
- Initial performance of R1 must be complete on or before the effective date of the standard.
- R2 completion is contingent upon whether verification recommends modification. If no, R2 is complete upon verification completion in R2.2. If yes, R2 is complete upon performing R2.3.
- R2 can be performed concurrently with R1
- R6 can be performed concurrently with R4 and R5

Rationale

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

Rationale for Requirement R1:
This requirement meets the FERC directive from paragraph 6 of its March 7, 2014 order on physical security to perform a risk assessment to identify which facilities if rendered inoperable or damaged could impact an Interconnection through instability, uncontrolled separation, or cascading failures. The requirement is not intended to bring within the scope of the standard a Transmission station or Transmission substation unless the applicable Transmission Owner determines through technical studies and analyses based on objective analysis, technical expertise, operating experience and experienced judgment that the loss of such facility would have a critical impact on the operation of the Interconnection in the event the asset is rendered inoperable or damaged. In the November 20, 2014 Order, FERC reiterated that "only an instability that has a "critical impact on the operation of the interconnection" warrants finding that the facility causing the instability is critical under Requirement R1." The Transmission Owner may determine the criteria for critical impact by considering, among other criteria, any of the following:

- Criteria or methodology used by Transmission Planners or Planning Coordinators in TPL-001-4, Requirement R6
- NERC EOP-004-2 reporting criteria
- Area or magnitude of potential impact

Requirement R1 also meets the FERC directive for periodic reevaluation of the risk assessment by requiring the risk assessment to be performed every 30 months (or 60 months for an entity that has not identified in a previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection).

After identifying each Transmission station and Transmission substation that meets the criteria in Requirement R1, it is important to additionally identify the primary control center that operationally controls that Transmission station or Transmission substation (*i.e.,* the control center whose electronic actions can cause direct physical actions at the identified Transmission station and Transmission substation, such as opening a breaker, compared to a control center that only has the ability to monitor the Transmission station and Transmission substation and, therefore, must coordinate direct physical action through another entity).

Rationale for Requirement R2:
This requirement meets the FERC directive from paragraph 11 in the order on physical security requiring verification by an entity other than the owner or operator of the risk assessment performed under Requirement R1.

This requirement provides the flexibility for a Transmission Owner to select registered and non-registered entities with transmission planning or analysis experience to perform the verification of the Requirement R1 risk assessment. The term "unaffiliated" means that the selected verifying entity cannot be a corporate affiliate (*i.e.*, the verifying entity cannot be an entity that controls, is controlled by, or is under common control with, the Transmission owner). The verifying entity also cannot be a division of the Transmission Owner that operates as a functional unit. The term "unaffiliated" is not intended to prohibit a governmental entity from using another government entity to be a verifier under Requirement R2.

Requirement R2 also provides the Transmission Owner the flexibility to work with the verifying entity throughout the Requirement R1 risk assessment, which for some Transmission Owners may be more efficient and effective. In other words, a Transmission Owner could coordinate with their unaffiliated verifying entity to perform a Requirement R1 risk assessment to satisfy both Requirement R1 and Requirement R2 concurrently.

Planning Coordinator is a functional entity listed in Part 2.1. The Planning Coordinator and Planning Authority are the same entity as shown in the NERC Glossary of Terms Used in NERC Reliability Standards.

Rationale for Requirement R3:
Some Transmission Operators will have obligations under this standard for certain primary control centers. Those obligations, however, are contingent upon a Transmission Owner first identifying which Transmission stations and Transmission substations meet the criteria specified by Requirement R1, as verified according to Requirement R2. This requirement is intended to ensure that a Transmission Operator that has operational control of a primary control center identified in Requirement R1, Part 1.2 of a Transmission station or Transmission substation verified according to Requirement R2 receives notice of such identification so that the Transmission Operator may timely fulfill its resulting obligations under Requirements R4 through R6. Since the timing obligations in Requirements R4 through R6 are based upon completion of Requirement R2, the Transmission Owner must also include notice of the date of completion of Requirement R2. Similarly, the Transmission Owner must notify the Transmission Operator of any removals from identification that result from a subsequent risk assessment under Requirement R1 or the verification process under Requirement R2.

Rationale for Requirement R4:
This requirement meets the FERC directive from paragraph 8 in the order on physical security that the reliability standard must require tailored evaluation of potential threats and vulnerabilities to facilities identified in Requirement R1 and verified according to Requirement R2. Threats and vulnerabilities may vary from facility to facility based on factors such as the facility's location, size, function, existing protections, and attractiveness of the target. As such, the requirement does not mandate a one-size-fits-all approach but requires entities to account for the unique characteristics of their facilities.

Requirement R4 does not explicitly state when the evaluation of threats and vulnerabilities must occur or be completed. However, Requirement R5 requires that the entity's security

plan(s), which is dependent on the Requirement R4 evaluation, must be completed within 120 calendar days following completion of Requirement R2. Thus, an entity has the flexibility when to complete the Requirement R4 evaluation, provided that it is completed in time to comply with the requirement in Requirement R5 to develop a physical security plan 120 calendar days following completion of Requirement R2.

Rationale for Requirement R5:
This requirement meets the FERC directive from paragraph 9 in the order on physical security requiring the development and implementation of a security plan(s) designed to protect against attacks to the facilities identified in Requirement R1 based on the assessment performed under Requirement R4.

Rationale for Requirement R6:
This requirement meets the FERC directive from paragraph 11 in the order on physical security requiring review by an entity other than the owner or operator with appropriate expertise of the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5.

As with the verification required by Requirement R2, Requirement R6 provides Transmission Owners and Transmission Operators the flexibility to work with the third party reviewer throughout the Requirement R4 evaluation and the development of the Requirement R5 security plan(s). This would allow entities to satisfy their obligations under Requirement R6 concurrent with the satisfaction of their obligations under Requirements R4 and R5.

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

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 initial ballot	August 2018 – September 2018
10-day final ballot	September 2018
NERC Board adoption	November 2018

A. Introduction

1. **Title:** Transmission Vegetation Management

2. **Number:** FAC-003-54

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

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Applicable Transmission Owners

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

   4.1.2. Applicable Generator Owners

   4.1.2.1. Generator Owners that own generation Facilities defined in 4.3.

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

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

   4.2.2. Each overhead transmission line operated below 200kV, identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation.~~identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator.~~

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

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

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

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

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

4.3.1.1. Operated at 200kV or higher; or

4.3.1.2. Operated below 200kV and are identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation.~~identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator~~; or

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

5. Effective Date: See Implementation Plan

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

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

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

c) Competency-based defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: *who, under what*

[2] *Id.*

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

conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?

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

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

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

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

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

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

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

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

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

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

B. Requirements and Measures

R1. Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the Minimum Vegetation Clearance Distance (MVCD) of its applicable line(s), ~~which are either an element of an IROL, or an element of a Major WECC Transfer Path;~~ operating within their Rating and all

Rated Electrical Operating Conditions of the types shown below[4] *[Violation Risk Factor: High] [Time Horizon: Real-time]*:

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

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

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

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

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

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

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

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

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

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

[7] *Id.*

[8] *Id.*

~~[9] See footnote 4.~~

~~[10] See footnote 5.~~

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

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

~~2.4.~~2.1. ~~An encroachment due to vegetation growth into the line MVCD that caused a vegetation-related Sustained Outage.[13]~~

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

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

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

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

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

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

M4. Each applicable Transmission Owner and applicable Generator Owner that has a confirmed vegetation condition likely to cause a Fault at any moment will have evidence that it notified the control center holding switching authority for the

~~[11] See footnote 6.~~
~~[12] *Id.*~~

~~[13] *Id.*~~

associated transmission line without any intentional time delay. Examples of evidence may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders. (R4)

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

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

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

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

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

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

Examples of reasons for modification to annual plan may include [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]:

7.1. Change in expected growth rate/environmental factors

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

7.3. Rescheduling work between growing seasons

7.4. Crew or contractor availability/Mutual assistance agreements

7.5. Identified unanticipated high priority work

7.6. Weather conditions/Accessibility

7.7. Permitting delays

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

7.9. Emerging technologies

M7. Each applicable Transmission Owner and applicable Generator Owner has evidence that it completed its annual vegetation work plan for its applicable lines. Examples of acceptable forms of evidence may include a copy of the completed annual work plan (as finally modified), dated work orders, dated invoices, or dated inspection records. (R7)

C. Compliance

1. Compliance Monitoring Process

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

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

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

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

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

1.3. Compliance Monitoring and Enforcement Program

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

1.4. Additional Compliance Information

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

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

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

- Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, that are identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only), as Facilities that if lost or degraded are expected to result in instances of instability,

Cascading, or uncontrolled separation~~as an element of an IROL or Major WECC Transfer Path~~, by vegetation inside and/or outside of the ROW;

- Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, but are not identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lostor degraded are expected to result in instances of instability, Cascading, or uncontrolled separation~~as an element of an IROL or Major WECC Transfer Path~~, by vegetation inside and/or outside of the ROW;
- Category 2A — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines that are identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are epected to result in instances of instability, Cascading, or uncontrolled separation~~as an element of an IROL or Major WECC Transfer Path~~, from within the ROW;
- Category 2B — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines, but are not identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation~~as an element of an IROL or Major WECC Transfer Path~~, from within the ROW;
- Category 3 — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines from outside the ROW;
- Category 4A — Blowing together: Sustained Outages caused by vegetation and applicable lines that are identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation~~as an element of an IROL or Major WECC Transfer Path~~, blowing together from within the ROW;
- Category 4B — Blowing together: Sustained Outages caused by vegetation and applicable lines, but are not identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation~~as an element of an IROL or Major WECC Transfer Path~~, blowing together from within the ROW.

The Regional Entity will report the outage information provided by applicable Transmission Owners and applicable Generator Owners, as per

the above, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported Sustained Outages.

Violation Severity Levels (Table 1)

R #	Table 1: Violation Severity Levels (VSL)			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.			The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation ~~as an element of an IROL or Major WECC transfer path~~ and encroachment into the MVCD as identified in FAC-003-4-Table 2 was observed in real time absent a Sustained Outage.	The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation ~~as an element of an IROL or Major WECC transfer path~~ and a vegetation-related Sustained Outage was caused by one of the following: • *A fall-in from inside the active transmission line ROW*

				• *Blowing together of applicable lines and vegetation located inside the active transmission line ROW* • *A grow-in*
R2.			~~The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-4 Table 2 was observed in real time absent a Sustained Outage.~~	~~The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and a vegetation-related Sustained Outage was caused by one of the following:~~ • ~~*A fall-in from inside the active transmission line ROW*~~ • ~~*Blowing together of applicable lines and vegetation located inside the active transmission line ROW*~~ • ~~*A grow-in*~~
R3.		The responsible entity has maintenance strategies or documented procedures or	The responsible entity has maintenance strategies or documented procedures or	The responsible entity does not have any maintenance strategies or documented

		processes or specifications but has not accounted for the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the responsible entity's applicable lines. (Requirement R3, Part 3.2.)	processes or specifications but has not accounted for the movement of transmission line conductors under their Rating and all Rated Electrical Operating Conditions, for the responsible entity's applicable lines. (Requirement R3, Part 3.1.)	procedures or processes or specifications used to prevent the encroachment of vegetation into the MVCD, for the responsible entity's applicable lines.
R4.			The responsible entity experienced a confirmed vegetation threat and notified the control center holding switching authority for that applicable line, but there was intentional delay in that notification.	The responsible entity experienced a confirmed vegetation threat and did not notify the control center holding switching authority for that applicable line.
R5.				The responsible entity did not take corrective action when it was constrained from performing planned vegetation work where an applicable line was put at potential risk.
R6.	The responsible entity failed to inspect 5% or less of its applicable lines (measured in units of choice - circuit, pole	The responsible entity failed to inspect more than 5% up to and including 10% of its applicable lines (measured in	The responsible entity failed to inspect more than 10% up to and including 15% of its applicable lines (measured in	The responsible entity failed to inspect more than 15% of its applicable lines (measured in units of choice

	line, line miles or kilometers, etc.)	units of choice - circuit, pole line, line miles or kilometers, etc.).	units of choice - circuit, pole line, line miles or kilometers, etc.).	- circuit, pole line, line miles or kilometers, etc.).
R7.	The responsible entity failed to complete 5% or less of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 5% and up to and including 10% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 10% and up to and including 15% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 15% of its annual vegetation work plan for its applicable lines (as finally modified).

D. Regional Variances

None.

E. Associated Documents

- FAC-003-4 Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	January 20, 2006	1. Added “Standard Development Roadmap.” 2. Changed “60” to “Sixty” in section A, 5.2. 3. Added “Proposed Effective Date: April 7, 2006” to footer. 4. Added “Draft 3: November 17, 2005” to footer.	New
1	April 4, 2007	Regulatory Approval - Effective Date	New

2	November 3, 2011	Adopted by the NERC Board of Trustees	New
2	March 21, 2013	FERC Order issued approving FAC-003-2 (Order No. 777) FERC Order No. 777 was issued on March 21, 2013 directing NERC to "conduct or contract testing to obtain empirical data and submit a report to the Commission providing the results of the testing."[16]	Revisions
2	May 9, 2013	Board of Trustees adopted the modification of the VRF for Requirement R2 of FAC-003-2 by raising the VRF from "Medium" to "High."	Revisions
3	May 9, 2013	FAC-003-3 adopted by Board of Trustees	Revisions
3	September 19, 2013	A FERC order was issued on September 19, 2013, approving FAC-003-3. This standard became enforceable on July 1, 2014 for Transmission Owners. For Generator Owners, R3 became enforceable on January 1, 2015 and all other requirements (R1, R2, R4, R5, R6, and R7) became enforceable on January 1, 2016.	Revisions
3	November 22, 2013	Updated the VRF for R2 from "Medium" to "High" per a Final Rule issued by FERC	Revisions
3	July 30, 2014	Transferred the effective dates section from FAC-003-2 (for Transmission Owners) into FAC-003-3, per the FAC-003-3 implementation plan	Revisions

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

4	February 11, 2016	Adopted by Board of Trustees. Adjusted MVCD values in Table 2 for alternating current systems, consistent with findings reported in report filed on August 12, 2015 in Docket No. RM12-4-002 consistent with FERC's directive in Order No. 777, and based on empirical testing results for flashover distances between conductors and vegetation.	Revisions
4	March 9, 2016	Corrected subpart 7.10 to M7, corrected value of .07 to .7	Errata
4	April 26, 2016	FERC Letter Order approving FAC-003-4. Docket No. RD16-4-000.	

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

For **Alternating Current** Voltages (feet)

(AC) Nominal System Voltage (KV)+	(AC) Maximum System Voltage (kV)[18]	MVCD (feet) Over sea level up to 500 ft	MVCD feet Over 500 ft up to 1000 ft	MVCD feet Over 1000 ft up to 2000 ft	MVCD feet Over 2000 ft up to 3000 ft	MVCD feet Over 3000 ft up to 4000 ft	MVCD feet Over 4000 ft up to 5000 ft	MVCD feet Over 5000 ft up to 6000 ft	MVCD feet Over 6000 ft up to 7000 ft	MVCD feet Over 7000 ft up to 8000 ft	MVCD feet Over 8000 ft up to 9000 ft	MVCD feet Over 9000 ft up to 10000 ft	MVCD feet Over 10000 ft up to 11000 ft	MVCD feet Over 11000 ft up to 12000 ft	MVCD feet Over 12000 ft up to 13000 ft	MVCD feet Over 13000 ft up to 14000 ft	MVCD feet Over 14000 ft up to 15000 ft
765	800	11.6ft	11.7ft	11.9ft	12.1ft	12.2ft	12.4ft	12.6ft	12.8ft	13.0ft	13.1ft	13.3ft	13.5ft	13.7ft	13.9ft	14.1ft	14.3ft
500	550	7.0ft	7.1ft	7.2ft	7.4ft	7.5ft	7.6ft	7.8ft	7.9ft	8.1ft	8.2ft	8.3ft	8.5ft	8.6ft	8.8ft	8.9ft	9.1ft
345	362[19]	4.3ft	4.3ft	4.4ft	4.5ft	4.6ft	4.7ft	4.8ft	4.9ft	5.0ft	5.1ft	5.2ft	5.3ft	5.4ft	5.5ft	5.6ft	5.7ft
287	302	5.2ft	5.3ft	5.4ft	5.5ft	5.6ft	5.7ft	5.8ft	5.9ft	6.1ft	6.2ft	6.3ft	6.4ft	6.5ft	6.6ft	6.8ft	6.9ft
230	242	4.0ft	4.1ft	4.2ft	4.3ft	4.3ft	4.4ft	4.5ft	4.6ft	4.7ft	4.8ft	4.9ft	5.0ft	5.1ft	5.2ft	5.3ft	5.4ft
161*	169	2.7ft	2.7ft	2.8ft	2.9ft	2.9ft	3.0ft	3.0ft	3.1ft	3.2ft	3.3ft	3.3ft	3.4ft	3.5ft	3.6ft	3.7ft	3.8ft
138*	145	2.3ft	2.3ft	2.4ft	2.4ft	2.5ft	2.5ft	2.6ft	2.7ft	2.7ft	2.8ft	2.8ft	2.9ft	3.0ft	3.0ft	3.1ft	3.2ft
115*	121	1.9ft	1.9ft	1.9ft	2.0ft	2.0ft	2.1ft	2.1ft	2.2ft	2.2ft	2.3ft	2.3ft	2.4ft	2.5ft	2.5ft	2.6ft	2.7ft
88*	100	1.5ft	1.5ft	1.6ft	1.6ft	1.7ft	1.7ft	1.8ft	1.8ft	1.8ft	1.9ft	1.9ft	2.0ft	2.0ft	2.1ft	2.2ft	2.2ft
69*	72	1.1ft	1.1ft	1.1ft	1.2ft	1.2ft	1.2ft	1.2ft	1.3ft	1.3ft	1.3ft	1.4ft	1.4ft	1.4ft	1.5ft	1.6ft	1.6ft

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

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

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

[19] The change in transient overvoltage factors in the calculations are the driver in the decrease in MVCDs for voltages of 345 kV and above. Refer to pp.29-31 in the Supplemental Materials for additional information.

[+] *Table 2 – Table of MVCD values at a 1.0 gap factor (in U.S. customary units), which is located in the EPRI report filed with FERC on August 12, 2015. (The 14000-15000 foot values were subsequently provided by EPRI in an updated Table 2 on December 1, 2015, filed with the FAC-003-4 Petition at FERC)*

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[20]

For **Alternating Current** Voltages (meters)

(AC) Nominal System Voltage (KV)[+]	(AC) Maximum System Voltage (kV)[21]	MVCD meters Over sea level up to 153 m	MVCD meters Over 153m up to 305m	MVCD meters Over 305m up to 610m	MVCD meters Over 610m up to 915m	MVCD meters Over 915m up to 1220m	MVCD meters Over 1220m up to 1524m	MVCD meters Over 1524m up to 1829m	MVCD meters Over 1829m up to 2134m	MVCD meters Over 2134m up to 2439m	MVCD meters Over 2439m up to 2744m	MVCD meters Over 2744m up to 3048m	MVCD meters Over 3048m up to 3353m	MVCD meters Over 3353m up to 3657m	MVCD meters Over 3657m up to 3962m	MVCD meters Over 3962 m up to 4268 m	MVCD meters Over 4268 m up to 4572 m
765	800	3.6m	3.6m	3.6m	3.7m	3.7m	3.8m	3.8m	3.9m	4.0m	4.0m	4.1m	4.1m	4.2m	4.2m	4.3m	4.4m
500	550	2.1m	2.2m	2.2m	2.3m	2.3m	2.3m	2.4m	2.4m	2.5m	2..5m	2.5m	2.6m	2.6m	2.7m	2.7m	2.7m
345	362[22]	1.3m	1.3m	1.3m	1.4m	1.4m	1.4m	1.5m	1.5m	1.5m	1.6m	1.6m	1.6m	1.6m	1.7m	1.7m	1.8m
287	302	1.6m	1.6m	1.7m	1.7m	1.7m	1.7m	1.8m	1.8m	1.9m	1.9m	1.9m	2.0m	2.0m	2.0m	2.1m	2.1m
230	242	1.2m	1.3m	1.3m	1.3m	1.3m	1.3m	1.4m	1.4m	1.4m	1.5m	1.5m	1.5m	1.6m	1.6m	1.6m	1.6m
161*	169	0.8m	0.8m	0.9m	0.9m	0.9m	0.9m	0.9m	1.0m	1.0m	1.0m	1.0m	1.0m	1.1m	1.1m	1.1m	1.1m
138*	145	0.7m	0.7m	0.7m	0.7m	0.7m	0.7m	0.8m	0.8m	0.8m	0.9m	0.9m	0.9m	0.9m	0.9m	1.0m	1.0m
115*	121	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.7m	0.7m	0.7m	0.7m	0.7m	0.8m	0.8m	0.8m	0.8m
88*	100	0.4m	0.4m	0.5m	0.5m	0.5m	0.5m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.7m	0.7m
69*	72	0.3m	0.3m	0.3m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.5m	0.5m	0.5m

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

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

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

[22] The change in transient overvoltage factors in the calculations are the driver in the decrease in MVCDs for voltages of 345 kV and above. Refer to pp.29-31 in the supplemental materials for additional information.

[+] Table 2 – Table of MVCD values at a 1.0 gap factor (in U.S. customary units), which is located in the EPRI report filed with FERC on August 12, 2015. (The 14000-15000 foot values were subsequently provided by EPRI in an updated Table 2 on December 1, 2015, filed with the FAC-003-4 Petition at FERC)

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[23]

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

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

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

Guideline and Technical Basis

Effective dates:

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

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

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

Defined Terms:

Explanation for revising the definition of ROW:

The current NERC glossary definition of Right of Way has been modified to include Generator Owners and to address the matter set forth in Paragraph 734 of FERC Order 693. The Order pointed out that Transmission Owners may in some cases own more property or rights than are needed to reliably operate transmission lines. This definition represents a slight but significant departure from the strict legal definition of "right of way" in that this definition is based on engineering and construction considerations that establish the width of a corridor from a technical basis. The pre-2007 maintenance records are included in the current definition to allow the use of such vegetation widths if there were no engineering or construction standards that referenced the width of right of way to be maintained for vegetation on a particular line but the evidence exists in maintenance records for a width that was in fact maintained prior to this standard becoming mandatory. Such widths may be the only information available for lines that had limited or no vegetation easement rights and were typically maintained primarily to ensure public safety. This standard does not require additional easement rights to be purchased to satisfy a minimum right of way width that did not exist prior to this standard becoming mandatory.

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

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

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

RM12-4-000, the gap factor used in the Gallet equation required adjustment from 1.3 to 1.0. This resulted in increased MVCD values for all alternating current system voltages identified. The adjusted MVCD values, reflecting the 1.0 gap factor, are included in Table 2 of version 4 of FAC-003.

The air gap testing completed by EPRI per FERC Order No. 777 established that trees with large spreading canopies growing directly below energized high voltage conductors create the greatest likelihood of an air gap flash over incident and was a key driver in changing the gap factor to a more conservative value of 1.0 in version 4 of this standard.

Requirements R1 and R2:

R1 and R2 are performance-based requirements. The reliability objective or outcome to be achieved is the management of vegetation such that there are no vegetation encroachments within a minimum distance of transmission lines. Content-wise, R1 and R2 are the same requirements; however, they apply to different Facilities. Both R1 and R2 require each applicable Transmission Owner or applicable Generator Owner to manage vegetation to prevent encroachment within the MVCD of transmission lines. R1 is applicable to lines that are identified as an element ~~of an IROL or Major WECC Transfer Path~~by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation. R2 is applicable to all other lines that are not identified as an element by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation~~pursuant to FAC-015-1 Requirement R4elements of IROLs, and not elements of Major WECC Transfer Paths~~.

The separation of applicability (between R1 and R2) recognizes that inadequate vegetation management for an applicable line has been identified as an element by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lostor degraded are expected to result in instances of instability, Cascading, or uncontrolled separation~~that is an element of an IROL or a Major WECC Transfer Path~~ is a greater risk to the interconnected electric transmission system than applicable lines that ~~are not elements of IROLs or Major WECC Transfer Paths~~have not been identified as such. Applicable lines that ~~are not elements of IROLs or Major WECC Transfer Paths~~have not been identified as such do require effective vegetation management, but these lines are comparatively less operationally significant.

Requirements R1 and R2 state that if inadequate vegetation management allows vegetation to encroach within the MVCD distance as shown in Table 2, it is a violation of the standard. Table 2 distances are the minimum clearances that will prevent spark-over based on the Gallet equations. These requirements assume that transmission lines and their conductors are operating within their Rating. If a line conductor is intentionally or inadvertently operated beyond its Rating and Rated Electrical Operating Condition (potentially in violation of other standards), the occurrence

of a clearance encroachment may occur solely due to that condition. For example, emergency actions taken by an applicable Transmission Owner or applicable Generator Owner or Reliability Coordinator to protect an Interconnection may cause excessive sagging and an outage. Another example would be ice loading beyond the line's Rating and Rated Electrical Operating Condition. Such vegetation-related encroachments and outages are not violations of this standard.

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

With this approach, the VSLs for R1 and R2 are structured such that they directly correlate to the severity of a failure of an applicable Transmission Owner or applicable Generator Owner to manage vegetation and to the corresponding performance level of the Transmission Owner's vegetation program's ability to meet the objective of "preventing the risk of those vegetation related outages that could lead to Cascading." Thus violation severity increases with an applicable Transmission Owner's or applicable Generator Owner's inability to meet this goal and its potential of leading to a Cascading event. The additional benefits of such a combination are that it simplifies the standard and clearly defines performance for compliance. A performance-based requirement of this nature will promote high quality, cost effective vegetation management programs that will deliver the overall end result of improved reliability to the system.

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

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

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

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

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

1. *the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated*
2. *the work methods that the applicable Transmission Owner or applicable Generator Owner uses to control vegetation*
3. *a stated Vegetation Inspection frequency*
4. *an annual work plan*

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

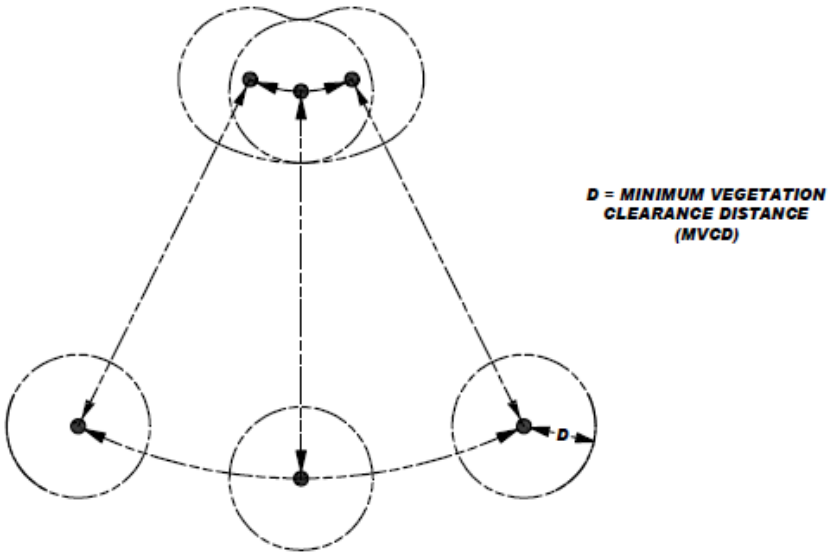


Figure 1

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

Requirement R4:
R4 is a risk-based requirement. It focuses on preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Fault risk when a vegetation threat is confirmed. R4 involves the notification of potentially threatening vegetation conditions, without any intentional delay, to the control center holding switching authority for that specific transmission line. Examples of acceptable unintentional delays may include communication system problems (for example, cellular service or two-way radio disabled), crews located in remote field locations with no communication access, delays due to severe weather, etc.

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

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

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

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

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

This requirement is not intended to address situations where the transmission line is not at potential risk and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of herbicides to control incompatible vegetation outside of the MVCD, but agree to the use of mechanical clearing. In this case the applicable Transmission Owner or applicable Generator Owner is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.

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

- Identifying locations where the applicable Transmission Owner or applicable Generator Owner is constrained from performing planned vegetation maintenance work which potentially leaves the transmission line at risk.
- Developing the specific action to mitigate any potential risk associated with not performing the vegetation maintenance work as planned.

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

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

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

For example, when an applicable Transmission Owner or applicable Generator Owner operates 2,000 miles of applicable transmission lines this applicable Transmission Owner or applicable Generator Owner will be responsible for inspecting all the 2,000 miles of lines at least once during the calendar year. If one of the included lines was 100 miles long, and if it was not inspected during the year, then the amount failed to inspect would be 100/2000 = 0.05 or 5%. The "Low VSL" for R6 would apply in this example.

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

management maintenance approach which successfully prevents encroachment of vegetation into the MVCD.

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

The ability to modify the work plan allows the applicable Transmission Owner or applicable Generator Owner to change priorities or treatment methodologies during the year as conditions or situations dictate. For example recent line inspections may identify unanticipated high priority work, weather conditions (drought) could make herbicide application ineffective during the plan year, or a major storm could require redirecting local resources away from planned maintenance. This situation may also include complying with mutual assistance agreements by moving resources off the applicable Transmission Owner's or applicable Generator Owner's system to work on another system. Any of these examples could result in acceptable deferrals or additions to the annual work plan provided that they do not put the transmission system at risk of a vegetation encroachment.
In general, the vegetation management maintenance approach should use the full extent of the applicable Transmission Owner's or applicable Generator Owner's easement, fee simple and other legal rights allowed. A comprehensive approach that exercises the full extent of legal rights on the ROW is superior to incremental management because in the long term it reduces the overall potential for encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient.

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

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. Therefore, deferrals or relevant changes to the annual plan shall be

documented. Depending on the planning and documentation format used by the applicable Transmission Owner or applicable Generator Owner, evidence of successful annual work plan execution could consist of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, or paid invoices. Other evidence may include photographs, and walk-through reports.

Notes:

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

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

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

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

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

FAC-003-1 allowed Transmission Owners to use either Table 5 or Table 7 to establish the minimum clearance distances. Table 7 could be used if the Transmission Owner knew the maximum transient over-voltage factor for its system. Otherwise, Table 5 would have to be used. Table 5 represented minimum air insulation distances under the worst possible case for transient over-voltage factors. These worst case transient over-voltage factors were as follows: 3.5 for voltages up to 362 kV phase to phase; 3.0 for 500 - 550 kV phase to phase; and 2.5 for 765 to 800 kV phase to phase. These worst case over-voltage factors were also a cause for concern in this particular application of the distances.

In general, the worst case transient over-voltages occur on a transmission line that is inadvertently re-energized immediately after the line is de-energized and a trapped charge is

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

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

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

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

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

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

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

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

Comparison of spark-over distances computed using Gallet wet equations vs.

IEEE 516-2003 MAID distances

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

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

Rationale for Applicability (section 4.2.4):
The areas excluded in 4.2.4 were excluded based on comments from industry for reasons summarized as follows:

1) There is a very low risk from vegetation in this area. Based on an informal survey, no TOs reported such an event.
2) Substations, switchyards, and stations have many inspection and maintenance activities that are necessary for reliability. Those existing process manage the threat. As such, the formal steps in this standard are not well suited for this environment.
3) Specifically addressing the areas where the standard does and does not apply makes the standard clearer.

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

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

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

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

Rationale for R3:
The documentation provides a basis for evaluating the competency of the applicable Transmission Owner's or applicable Generator Owner's vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the

applicable Transmission Owner or applicable Generator Owner avoids vegetation-to-wire conflicts under all Ratings and all Rated Electrical Operating Conditions.

Rationale for R4:

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

Rationale for R5:

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

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

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

Rationale for R6:

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

Rationale for R7:

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

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

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 initial ballot	August 2018 – September 2018
10-day final ballot	September 2018
NERC Board adoption	November 2018

A. Introduction

1. **Title:** Transmission Vegetation Management

2. **Number:** FAC-003-5

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

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Applicable Transmission Owners

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

   4.1.2. Applicable Generator Owners

   4.1.2.1. Generator Owners that own generation Facilities defined in 4.3.

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

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

   4.2.2. Each overhead transmission line operated below 200kV, identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation.

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

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

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

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

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

4.3.1.1. Operated at 200kV or higher; or

4.3.1.2. Operated below 200kV and are identified by the Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation.; or

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

5. Effective Date: See Implementation Plan

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

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

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

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

[2] *Id.*

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

outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?

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

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

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

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

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

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

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

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

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

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

B. Requirements and Measures

R1. Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the Minimum Vegetation Clearance Distance (MVCD) of its applicable line(s), operating within their Rating and all Rated

Electrical Operating Conditions of the types shown below[4] *[Violation Risk Factor: High] [Time Horizon: Real-time]*:

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

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

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

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

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

R2. [Reserved for future use]

2.1.

M2. [Reserved for future use]

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

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

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

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

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

[7] *Id.*

[8] *Id.*

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

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

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

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

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

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

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

year and with no more than 18 calendar months between inspections on the same ROW[9] [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

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

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

- **7.1.** Change in expected growth rate/environmental factors
- **7.2.** Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner[10]
- **7.3.** Rescheduling work between growing seasons
- **7.4.** Crew or contractor availability/Mutual assistance agreements
- **7.5.** Identified unanticipated high priority work
- **7.6.** Weather conditions/Accessibility
- **7.7.** Permitting delays
- **7.8.** Land ownership changes/Change in land use by the landowner
- **7.9.** Emerging technologies

M7. Each applicable Transmission Owner and applicable Generator Owner has evidence that it completed its annual vegetation work plan for its applicable lines. Examples of acceptable forms of evidence may include a copy of the completed annual work plan

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

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

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

C. Compliance

1. Compliance Monitoring Process

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

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

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

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

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

1.4. Additional Compliance Information

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

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

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

- Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, that are identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only), as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation, by vegetation inside and/or outside of the ROW;

- Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, but are not identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lostor degraded are expected to result in instances of instability, Cascading, or uncontrolled separation, by vegetation inside and/or outside of the ROW;

- Category 2A — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines that are identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are epected to result in instances of instability, Cascading, or uncontrolled separation, from within the ROW;

- Category 2B — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines, but are not identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation, from within the ROW;

- Category 3 — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines from outside the ROW;

- Category 4A — Blowing together: Sustained Outages caused by vegetation and applicable lines that are identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation, blowing together from within the ROW;
- Category 4B — Blowing together: Sustained Outages caused by vegetation and applicable lines, but are not identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation, blowing together from within the ROW.

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

Violation Severity Levels (Table 1)

R #	Table 1: Violation Severity Levels (VSL)			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.			The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation and encroachment into the MVCD as identified in FAC-003-4-Table 2 was observed in real time absent a Sustained Outage.	The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation and a vegetation-related Sustained Outage was caused by one of the following: • *A fall-in from inside the active transmission line ROW* • *Blowing together of applicable lines and*

				vegetation located inside the active transmission line ROW • *A grow-in*
R2.				•
R3.		The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the responsible entity's applicable lines. (Requirement R3, Part 3.2.)	The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the movement of transmission line conductors under their Rating and all Rated Electrical Operating Conditions, for the responsible entity's applicable lines. (Requirement R3, Part 3.1.)	The responsible entity does not have any maintenance strategies or documented procedures or processes or specifications used to prevent the encroachment of vegetation into the MVCD, for the responsible entity's applicable lines.
R4.			The responsible entity experienced a confirmed vegetation threat and notified the control center holding switching authority for that applicable line, but there was intentional delay in that notification.	The responsible entity experienced a confirmed vegetation threat and did not notify the control center holding switching authority for that applicable line.
R5.				The responsible entity did not take corrective action

				when it was constrained from performing planned vegetation work where an applicable line was put at potential risk.
R6.	The responsible entity failed to inspect 5% or less of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.)	The responsible entity failed to inspect more than 5% up to and including 10% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The responsible entity failed to inspect more than 10% up to and including 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The responsible entity failed to inspect more than 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).
R7.	The responsible entity failed to complete 5% or less of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 5% and up to and including 10% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 10% and up to and including 15% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 15% of its annual vegetation work plan for its applicable lines (as finally modified).

D. Regional Variances

None.

E. Associated Documents

- FAC-003-4 Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	January 20, 2006	1. Added "Standard Development Roadmap." 2. Changed "60" to "Sixty" in section A, 5.2. 3. Added "Proposed Effective Date: April 7, 2006" to footer. 4. Added "Draft 3: November 17, 2005" to footer.	New
1	April 4, 2007	Regulatory Approval - Effective Date	New
2	November 3, 2011	Adopted by the NERC Board of Trustees	New
2	March 21, 2013	FERC Order issued approving FAC-003-2 (Order No. 777) FERC Order No. 777 was issued on March 21, 2013 directing NERC to "conduct or contract testing to obtain empirical data and submit a report to the Commission providing the results of the testing."[11]	Revisions
2	May 9, 2013	Board of Trustees adopted the modification of the VRF for Requirement R2 of FAC-003-2 by raising the VRF from "Medium" to "High."	Revisions
3	May 9, 2013	FAC-003-3 adopted by Board of Trustees	Revisions
3	September 19, 2013	A FERC order was issued on September 19, 2013, approving FAC-003-3. This standard became enforceable on July 1, 2014 for Transmission Owners. For Generator Owners, R3 became enforceable on January 1, 2015 and all other	Revisions

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

		requirements (R1, R2, R4, R5, R6, and R7) became enforceable on January 1, 2016.	
3	November 22, 2013	Updated the VRF for R2 from “Medium” to “High” per a Final Rule issued by FERC	Revisions
3	July 30, 2014	Transferred the effective dates section from FAC-003-2 (for Transmission Owners) into FAC-003-3, per the FAC-003-3 implementation plan	Revisions
4	February 11, 2016	Adopted by Board of Trustees. Adjusted MVCD values in Table 2 for alternating current systems, consistent with findings reported in report filed on August 12, 2015 in Docket No. RM12-4-002 consistent with FERC’s directive in Order No. 777, and based on empirical testing results for flashover distances between conductors and vegetation.	Revisions
4	March 9, 2016	Corrected subpart 7.10 to M7, corrected value of .07 to .7	Errata
4	April 26, 2016	FERC Letter Order approving FAC-003-4. Docket No. RD16-4-000.	

FAC-003 — TABLE 2 — Minimum Vegetation Clearance Distances (MVCD)[12]

For **Alternating Current** Voltages (feet)

(AC) Nominal System Voltage (KV)[+]	(AC) Maximum System Voltage (kV)[13]	MVCD (feet) Over sea level up to 500 ft	MVCD feet Over 500 ft up to 1000 ft	MVCD feet Over 1000 ft up to 2000 ft	MVCD feet Over 2000 ft up to 3000 ft	MVCD feet Over 3000 ft up to 4000 ft	MVCD feet Over 4000 ft up to 5000 ft	MVCD feet Over 5000 ft up to 6000 ft	MVCD feet Over 6000 ft up to 7000 ft	MVCD feet Over 7000 ft up to 8000 ft	MVCD feet Over 8000 ft up to 9000 ft	MVCD feet Over 9000 ft up to 10000 ft	MVCD feet Over 10000 ft up to 11000 ft	MVCD feet Over 11000 ft up to 12000 ft	MVCD feet Over 12000 ft up to 13000 ft	MVCD feet Over 13000 ft up to 14000 ft	MVCD feet Over 14000 ft up to 15000 ft
765	800	11.6ft	11.7ft	11.9ft	12.1ft	12.2ft	12.4ft	12.6ft	12.8ft	13.0ft	13.1ft	13.3ft	13.5ft	13.7ft	13.9ft	14.1ft	14.3ft
500	550	7.0ft	7.1ft	7.2ft	7.4ft	7.5ft	7.6ft	7.8ft	7.9ft	8.1ft	8.2ft	8.3ft	8.5ft	8.6ft	8.8ft	8.9ft	9.1ft
345	362[14]	4.3ft	4.3ft	4.4ft	4.5ft	4.6ft	4.7ft	4.8ft	4.9ft	5.0ft	5.1ft	5.2ft	5.3ft	5.4ft	5.5ft	5.6ft	5.7ft
287	302	5.2ft	5.3ft	5.4ft	5.5ft	5.6ft	5.7ft	5.8ft	5.9ft	6.1ft	6.2ft	6.3ft	6.4ft	6.5ft	6.6ft	6.8ft	6.9ft
230	242	4.0ft	4.1ft	4.2ft	4.3ft	4.3ft	4.4ft	4.5ft	4.6ft	4.7ft	4.8ft	4.9ft	5.0ft	5.1ft	5.2ft	5.3ft	5.4ft
161*	169	2.7ft	2.7ft	2.8ft	2.9ft	2.9ft	3.0ft	3.0ft	3.1ft	3.2ft	3.3ft	3.3ft	3.4ft	3.5ft	3.6ft	3.7ft	3.8ft
138*	145	2.3ft	2.3ft	2.4ft	2.4ft	2.5ft	2.5ft	2.6ft	2.7ft	2.7ft	2.8ft	2.8ft	2.9ft	3.0ft	3.0ft	3.1ft	3.2ft
115*	121	1.9ft	1.9ft	1.9ft	2.0ft	2.0ft	2.1ft	2.1ft	2.2ft	2.2ft	2.3ft	2.3ft	2.4ft	2.5ft	2.5ft	2.6ft	2.7ft
88*	100	1.5ft	1.5ft	1.6ft	1.6ft	1.7ft	1.7ft	1.8ft	1.8ft	1.8ft	1.9ft	1.9ft	2.0ft	2.0ft	2.1ft	2.2ft	2.2ft
69*	72	1.1ft	1.1ft	1.1ft	1.2ft	1.2ft	1.2ft	1.2ft	1.3ft	1.3ft	1.3ft	1.4ft	1.4ft	1.4ft	1.5ft	1.6ft	1.6ft

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

[+] *Table 2 – Table of MVCD values at a 1.0 gap factor (in U.S. customary units), which is located in the EPRI report filed with FERC on August 12, 2015. (The 14000-15000 foot values were subsequently provided by EPRI in an updated Table 2 on December 1, 2015, filed with the FAC-003-4 Petition at FERC)*

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

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

[14] The change in transient overvoltage factors in the calculations are the driver in the decrease in MVCDs for voltages of 345 kV and above. Refer to pp.29-31 in the Supplemental Materials for additional information.

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[15]

For **Alternating Current** Voltages (meters)

(AC) Nominal System Voltage (KV)[+]	(AC) Maximum System Voltage (kV)[16]	MVCD meters Over sea level up to 153 m	MVCD meters Over 153m up to 305m	MVCD meters Over 305m up to 610m	MVCD meters Over 610m up to 915m	MVCD meters Over 915m up to 1220m	MVCD meters Over 1220m up to 1524m	MVCD meters Over 1524m up to 1829m	MVCD meters Over 1829m up to 2134m	MVCD meters Over 2134m up to 2439m	MVCD meters Over 2439m up to 2744m	MVCD meters Over 2744m up to 3048m	MVCD meters Over 3048m up to 3353m	MVCD meters Over 3353m up to 3657m	MVCD meters Over 3657m up to 3962m	MVCD meters Over 3962 m up to 4268 m	MVCD meters Over 4268m up to 4572m
765	800	3.6m	3.6m	3.6m	3.7m	3.7m	3.8m	3.8m	3.9m	4.0m	4.0m	4.1m	4.1m	4.2m	4.2m	4.3m	4.4m
500	550	2.1m	2.2m	2.2m	2.3m	2.3m	2.3m	2.4m	2.4m	2.5m	2..5m	2.5m	2.6m	2.6m	2.7m	2.7m	2.7m
345	362[17]	1.3m	1.3m	1.3m	1.4m	1.4m	1.4m	1.5m	1.5m	1.5m	1.6m	1.6m	1.6m	1.6m	1.7m	1.7m	1.8m
287	302	1.6m	1.6m	1.7m	1.7m	1.7m	1.7m	1.8m	1.8m	1.9m	1.9m	1.9m	2.0m	2.0m	2.0m	2.1m	2.1m
230	242	1.2m	1.3m	1.3m	1.3m	1.3m	1.3m	1.4m	1.4m	1.4m	1.5m	1.5m	1.5m	1.6m	1.6m	1.6m	1.6m
161*	169	0.8m	0.8m	0.9m	0.9m	0.9m	0.9m	0.9m	1.0m	1.0m	1.0m	1.0m	1.0m	1.1m	1.1m	1.1m	1.1m
138*	145	0.7m	0.7m	0.7m	0.7m	0.7m	0.7m	0.8m	0.8m	0.8m	0.9m	0.9m	0.9m	0.9m	0.9m	1.0m	1.0m
115*	121	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.7m	0.7m	0.7m	0.7m	0.7m	0.8m	0.8m	0.8m	0.8m
88*	100	0.4m	0.4m	0.5m	0.5m	0.5m	0.5m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.7m	0.7m
69*	72	0.3m	0.3m	0.3m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.5m	0.5m	0.5m

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

[+] *Table 2 – Table of MVCD values at a 1.0 gap factor (in U.S. customary units), which is located in the EPRI report filed with FERC on August 12, 2015. (The 14000-15000 foot values were subsequently provided by EPRI in an updated Table 2 on December 1, 2015, filed with the FAC-003-4 Petition at FERC)*

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

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

[17] The change in transient overvoltage factors in the calculations are the driver in the decrease in MVCDs for voltages of 345 kV and above. Refer to pp.29-31 in the supplemental materials for additional information.

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[18]

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

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

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

Guideline and Technical Basis

Effective dates:

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

The special case is needed because the Planning Coordinators may designate lines below 200 kV, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation, in a future Planning Year (PY). For example, studies by the Planning Coordinator in 2015 may identify a line to have that designation beginning in PY 2025, ten years after the planning study is performed. It is not intended for the Standard to be immediately applicable to, or in effect for, that line until that future PY begins. The effective date provision for such lines ensures that the line will become subject to the standard on January 1 of the PY specified with an allowance of at least 12 months for the applicable Transmission Owner or applicable Generator Owner to make the necessary preparations to achieve compliance on that line. A line operating below 200kV designated by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network.

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

Defined Terms:

Explanation for revising the definition of ROW:
The current NERC glossary definition of Right of Way has been modified to include Generator Owners and to address the matter set forth in Paragraph 734 of FERC Order 693. The Order pointed out that Transmission Owners may in some cases own more property or rights than are needed to reliably operate transmission lines. This definition represents a slight but significant

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

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

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

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

The air gap testing completed by EPRI per FERC Order No. 777 established that trees with large spreading canopies growing directly below energized high voltage conductors create the greatest likelihood of an air gap flash over incident and was a key driver in changing the gap factor to a more conservative value of 1.0 in version 4 of this standard.

Requirements R1 and R2:
R1 and R2 are performance-based requirements. The reliability objective or outcome to be achieved is the management of vegetation such that there are no vegetation encroachments within a minimum distance of transmission lines. Content-wise, R1 and R2 are the same requirements; however, they apply to different Facilities. Both R1 and R2 require each applicable Transmission Owner or applicable Generator Owner to manage vegetation to prevent encroachment within the MVCD of transmission lines. R1 is applicable to lines that are identified as an element by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation. R2 is applicable to all other lines that are not identified as an element by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation.

The separation of applicability (between R1 and R2) recognizes that inadequate vegetation management for an applicable line has been identified as an element by the Planning Coordinator, per its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability Assessment (Planning Coordinator only) as Facilities that if lostor degraded are expected to result in instances of instability, Cascading, or uncontrolled separation is a greater risk to the interconnected electric transmission system than applicable lines that have not been identified as such. Applicable lines that have not been identified as such do require effective vegetation management, but these lines are comparatively less operationally significant.

Requirements R1 and R2 state that if inadequate vegetation management allows vegetation to encroach within the MVCD distance as shown in Table 2, it is a violation of the standard. Table 2 distances are the minimum clearances that will prevent spark-over based on the Gallet equations. These requirements assume that transmission lines and their conductors are operating within their Rating. If a line conductor is intentionally or inadvertently operated beyond its Rating and Rated Electrical Operating Condition (potentially in violation of other standards), the occurrence of a clearance encroachment may occur solely due to that condition. For example, emergency actions taken by an applicable Transmission Owner or applicable Generator Owner or Reliability Coordinator to protect an Interconnection may cause excessive sagging and an outage. Another example would be ice loading beyond the line's Rating and Rated Electrical Operating Condition. Such vegetation-related encroachments and outages are not violations of this standard.

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

With this approach, the VSLs for R1 and R2 are structured such that they directly correlate to the severity of a failure of an applicable Transmission Owner or applicable Generator Owner to manage vegetation and to the corresponding performance level of the Transmission Owner's vegetation program's ability to meet the objective of "preventing the risk of those vegetation related outages that could lead to Cascading." Thus violation severity increases with an applicable Transmission Owner's or applicable Generator Owner's inability to meet this goal and its potential of leading to a Cascading event. The additional benefits of such a combination are that it simplifies the standard and clearly defines performance for compliance. A performance-based requirement of this nature will promote high quality, cost effective vegetation management programs that will deliver the overall end result of improved reliability to the system.

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

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

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

An adequate transmission vegetation management program formally establishes the approach the applicable Transmission Owner or applicable Generator Owner uses to plan and perform vegetation work to prevent transmission Sustained Outages and minimize risk to the transmission system. The approach provides the basis for evaluating the intent, allocation of appropriate resources, and the competency of the applicable Transmission Owner or applicable Generator Owner in managing vegetation. There are many acceptable approaches to manage

vegetation and avoid Sustained Outages. However, the applicable Transmission Owner or applicable Generator Owner must be able to show the documentation of its approach and how it conducts work to maintain clearances.

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

1. *the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated*
2. *the work methods that the applicable Transmission Owner or applicable Generator Owner uses to control vegetation*
3. *a stated Vegetation Inspection frequency*
4. *an annual work plan*

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

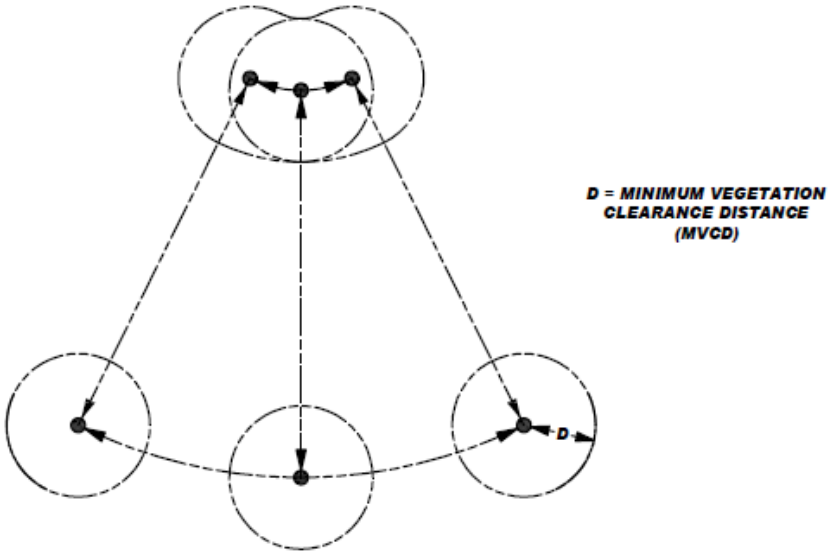

Figure 1

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

Requirement R4:
R4 is a risk-based requirement. It focuses on preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Fault risk when a vegetation threat is confirmed. R4 involves the notification of potentially threatening vegetation conditions, without any intentional delay, to the control center holding switching authority for that specific transmission line. Examples of acceptable unintentional delays may include communication system problems (for example, cellular service or two-way radio disabled), crews located in remote field locations with no communication access, delays due to severe weather, etc.

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

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

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

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

Requirement R5:
R5 is a risk-based requirement. It focuses upon preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Sustained

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

This requirement is not intended to address situations where the transmission line is not at potential risk and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of herbicides to control incompatible vegetation outside of the MVCD, but agree to the use of mechanical clearing. In this case the applicable Transmission Owner or applicable Generator Owner is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.

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

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

Requirement R6:
R6 is a risk-based requirement. This requirement sets a minimum time period for completing Vegetation Inspections. The provision that Vegetation Inspections can be performed in conjunction with general line inspections facilitates a Transmission Owner's ability to meet this requirement. However, the applicable Transmission Owner or applicable Generator Owner may determine that more frequent vegetation specific inspections are needed to maintain

reliability levels, based on factors such as anticipated growth rates of the local vegetation, length of the local growing season, limited ROW width, and local rainfall. Therefore it is expected that some transmission lines may be designated with a higher frequency of inspections.

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

For example, when an applicable Transmission Owner or applicable Generator Owner operates 2,000 miles of applicable transmission lines this applicable Transmission Owner or applicable Generator Owner will be responsible for inspecting all the 2,000 miles of lines at least once during the calendar year. If one of the included lines was 100 miles long, and if it was not inspected during the year, then the amount failed to inspect would be 100/2000 = 0.05 or 5%. The "Low VSL" for R6 would apply in this example.

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

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

The ability to modify the work plan allows the applicable Transmission Owner or applicable Generator Owner to change priorities or treatment methodologies during the year as conditions or situations dictate. For example recent line inspections may identify unanticipated high priority work, weather conditions (drought) could make herbicide application ineffective during the plan year, or a major storm could require redirecting local resources away from planned maintenance. This situation may also include complying with mutual assistance agreements by moving resources off the applicable Transmission Owner's or applicable Generator Owner's system to work on another system. Any of these examples could result in acceptable deferrals or additions to the annual work plan provided that they do not put the transmission system at risk of a vegetation encroachment.
In general, the vegetation management maintenance approach should use the full extent of the applicable Transmission Owner's or applicable Generator Owner's easement, fee simple and other legal rights allowed. A comprehensive approach that exercises the full extent of legal rights on the ROW is superior to incremental management because in the long term it reduces the overall potential for encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient.

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

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

Notes:

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

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

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

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

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

FAC-003-1 allowed Transmission Owners to use either Table 5 or Table 7 to establish the minimum clearance distances. Table 7 could be used if the Transmission Owner knew the maximum transient over-voltage factor for its system. Otherwise, Table 5 would have to be used. Table 5 represented minimum air insulation distances under the worst possible case for transient over-voltage factors. These worst case transient over-voltage factors were as follows: 3.5 for voltages up to 362 kV phase to phase; 3.0 for 500 - 550 kV phase to phase; and 2.5 for 765 to 800 kV phase to phase. These worst case over-voltage factors were also a cause for concern in this particular application of the distances.

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

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

Even though these transient over-voltages will not be experienced at locations remote from the bus at which they are created, in order to be conservative, it is assumed that all nearby ac lines

are subjected to this same level of over-voltage. Thus, a maximum transient over-voltage factor of 2.0 per unit for transmission lines operated at 302 kV and below was considered to be a realistic maximum in this application. Likewise, for ac transmission lines operated at Maximum System Voltages of 362 kV and above a transient over-voltage factor of 1.4 per unit was considered a realistic maximum.

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

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

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

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

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

Comparison of spark-over distances computed using Gallet wet equations vs.

IEEE 516-2003 MAID distances

(AC) **Nom System** **Voltage (kV)**	**(AC)** **Max System** **Voltage (kV)**	**Transient** **Over-voltage** **Factor (T)**	**Clearance (ft.)** **Gallet (wet)** **@ Alt. 3000 feet**	Table 7 (Table D.5 for feet) **IEEE 516-2003** **MAID (ft)** **@ Alt. 3000 feet**

765	800	2.0	14.36	13.95
500	550	2.4	11.0	10.07
345	362	3.0	8.55	7.47
230	242	3.0	5.28	4.2
115	121	3.0	2.46	2.1

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

Rationale for Applicability (section 4.2.4):
The areas excluded in 4.2.4 were excluded based on comments from industry for reasons summarized as follows:

1) There is a very low risk from vegetation in this area. Based on an informal survey, no TOs reported such an event.
2) Substations, switchyards, and stations have many inspection and maintenance activities that are necessary for reliability. Those existing process manage the threat. As such, the formal steps in this standard are not well suited for this environment.
3) Specifically addressing the areas where the standard does and does not apply makes the standard clearer.

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

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

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

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

Rationale for R3:
The documentation provides a basis for evaluating the competency of the applicable Transmission Owner’s or applicable Generator Owner’s vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the

applicable Transmission Owner or applicable Generator Owner avoids vegetation-to-wire conflicts under all Ratings and all Rated Electrical Operating Conditions.

Rationale for R4:

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

Rationale for R5:

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

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

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

Rationale for R6:

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

Rationale for R7:

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

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

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
45-day formal comment period with initial ballot	09/29/17 – 11/14/17

Anticipated Actions	Date
45-day formal comment period with additional ballot	August 2018 – October 2018
10-day final ballot	October 2018
NERC Board adoption	November 2018

A. Introduction

1. **Title:** System Operating Limits Methodology for the Operations Horizon

2. **Number:** FAC-011-4

3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Reliability Coordinator

5. **Effective Date:** See Implementation Plan for Project 2015-09.

B. Requirements and Measures

R1. Each Reliability Coordinator shall have a documented methodology for establishing SOLs (i.e., SOL Methodology) within its Reliability Coordinator Area. *[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.

R2. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine ~~the applicable~~which owner-provided Facility Ratings are to be used in operations~~. The method shall address the use of common Facility Ratings between the Reliability Coordinator and~~ such that the Transmission ~~Operators in~~Operator and its Reliability Coordinator ~~Area~~use common Facility Ratings. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. 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]*

3.1. Require that each BES bus~~es~~/station~~s~~ have an associated System Voltage Limit, unless ~~except for~~ the Reliability Coordinators SOL Methodology specifically allows the exclusion of BES buses/stations ~~that may be excluded as specified in the Reliability Coordinator's SOL Methodology~~from the requirement to have an associated System Voltage Limit;

3.2. Require that System Voltage Limits respect ~~the~~voltage-based Facility ~~voltage~~ Ratings;

3.3. Require that System Voltage Limits are ~~higher~~greater than or equal to in-service relay settings for under voltage load shedding ~~(UVLS) relay settings~~systems and Undervoltage Load Shedding Programs;

3.4. Identify the lowest allowable System Voltage Limit;

3.5. ~~Address~~Require ~~-~~the use of common System Voltage Limits between the ~~Reliability Coordinator and the~~ Transmission ~~Operators in~~Operator and its Reliability Coordinator ~~Area~~ and provide the method for determining the common System Voltage Limits to be used in operations;

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]*

4.1. Specify stability performance criteria, including any margins applied. The criteria shall, at a minimum, include the following:

4.1.1. steady-state voltage stability;

4.1.2. transient voltage response;

4.1.3. ~~angular~~unit stability; and

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~~stability limits are ~~identified~~determined, 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 and other automatic post-Contingency mitigation actions in establishing stability limits used in operations. ~~;~~

~~4.6.~~4.7. State that the ~~planned~~ use of underfrequency load shedding (UFLS) ~~is~~programs and Undervoltage Load Shedding Programs are 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~~identify in its SOL Methodology the ~~method for identifying the single Contingencies and multiple Contingencies~~Contingency events for use in determining stability limits and performing Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs~~).~~) for the area under study. The ~~method~~SOL Methodology shall ~~include~~: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1. ~~The~~Specify 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~~Normal Clearing, or without a Fault:

- generator;
- transmission circuit;
- transformer;
- shunt device; or
- single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

5.2. ~~Any~~Identify any additional single or multiple Contingency events or types of ~~single~~ Contingency events ~~identified~~for use in performing Operational Planning Analysis and Real-time Assessments.

~~5.2.~~5.3. Identify any additional single or multiple Contingency events or types of Contingency events 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~~Describe the method(s) for identifying which, if any, of the Contingency events provided by the Planning Coordinator or Transmission Planner in accordance with FAC-015-1, Requirement ~~R6 to identify the Contingencies for~~R4, to use in determining stability limits.

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, at a minimum, the following Bulk Electric System performance criteria: *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

6.1. The actual pre-Contingency state (Real-time monitoring and Real-time Assessment) and anticipated pre-Contingency state (Operational Planning Analysis) demonstrates the following:

6.1.1. Flow through Facilities are within Normal Ratings; however, Emergency Ratings may be used when System adjustments to return the flow within its Normal Rating could be executed and completed within the specified time duration of those Emergency Ratings.

6.1.2. Voltages are within normal System Voltage Limits; however, emergency System Voltage Limits may be used when System adjustments to return the voltage within its normal System Voltage Limits could be executed and completed within the specified time duration of those emergency System Voltage Limits.

6.1.3. Instability, Cascading or uncontrolled separation do not occur.

6.2. The evaluation of potential single Contingencies listed in Part 5.1.1 against the actual pre-Contingency state (Real-time monitoring and Real-time Assessments) and anticipated pre-Contingency state (Operational Planning Analysis) demonstrates the following:

6.2.1. Flow through Facilities are within applicable Emergency Ratings, provided that System adjustments could be executed and completed within the specified time duration of those Emergency Ratings. Flow through a Facility must not be above the Facility's highest Emergency Rating.

6.2.2. Voltages are within emergency System Voltage Limits.

6.2.3. Instability, Cascading or uncontrolled separation do not occur.

6.3. The evaluation of the potential Contingencies identified in Part 5.2 against the actual pre-Contingency state (Real-time monitoring and Real-time Assessments) and anticipated pre-Contingency state (Operational Planning Analysis) demonstrates that instability, Cascading, or uncontrolled separation does not occur.

6.4. The evaluation of the potential Contingencies identified in Part 5.3 demonstrates that instability does not occur.

6.5. In determining the System's response to any Contingency identified in Parts 5.1 through 5.3, planned load shedding is acceptable only after all other available System adjustments have been made.

M6. 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.

~~R6.~~R7. Each Reliability Coordinator shall include in its SOL Methodology: *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

~~6.1.~~7.1. A description of how to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs).

~~6.2.~~7.2. Criteria for determining when violating a SOL qualifies as an IROL and criteria for developing any associated IROL T_V.

~~M6.~~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 R6.

~~R7.~~R8. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to communicate their established SOLs ~~it established~~ to the ~~its~~ Reliability Coordinator~~(s)~~. The method shall address the periodicity for communicating established~~of~~ SOLs ~~communication~~. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

~~M7.~~M8. 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.

~~R8.~~R9. Each Reliability Coordinator shall provide its SOL Methodology ~~and any changes to the SOL Methodology prior to the effective date of the SOL Methodology,~~ to: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

~~8.1.~~9.1. Each~~Each adjacent Reliability Coordinator within an Interconnection, and each~~ Reliability Coordinator that requests and indicates it has a reliability-related need~~;~~ within 30 days of a request.

9.2. Each of the following entities prior to the effective date of the SOL methodology:

9.2.1. Each adjacent Reliability Coordinator within the same~~an~~ Interconnection;

~~8.1.1.~~9.2.2. Each Planning Coordinator and Transmission Planner that is responsible for planning any portion of the Reliability Coordinator Area;

~~8.1.2.~~9.2.3. Each Transmission Operator within its Reliability Coordinator Area~~.~~; and

9.2.4. Each Reliability Coordinator that has requested to receive updates and indicated it had a reliability-related need.

~~M8.~~M9. Acceptable evidence that the Reliability Coordinator provided its SOL Methodology to the entities identified in Requirement R8 may include, but is not limited to, dated electronic or hard copy documentation such as emails with receipts,

registered mail receipts, or postings to a secure web site with accompanying notification(s).

C. Compliance

1. Compliance Monitoring Process

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

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

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

- The Reliability Coordinator shall keep data or evidence of compliance with Requirements R1 through ~~R8~~R9 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.	N/A	N/A	N/A	The Reliability Coordinator did not have a SOL Methodology for establishing SOLs within its Reliability Coordinator Area.
R2.	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.
R3.	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.
R4.	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.
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.
R6.	The Reliability Coordinator failed to incorporate one of the Parts of Requirement R6 into its SOL Methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R6 into its SOL Methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R6 into its SOL Methodology.	The Reliability Coordinator failed to incorporate four of the Parts of Requirement R6 into its SOL Methodology.
~~R6~~R7.	N/A	N/A	The Reliability Coordinator failed to include Part ~~6~~7.1 (a description of how to identify the subset of SOLs that qualify as IROLs) in its SOL Methodology.	The Reliability Coordinator failed to include Parts ~~6~~7.1 and ~~6~~7.2 in its SOL Methodology.

			OR The Reliability Coordinator failed to include Part ~~6~~7.2 (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~~7.2 (criteria for developing any associated IROL T_v) in its SOL Methodology.	
~~R7~~R8.	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.
~~R8~~R9.	The Reliability Coordinator failed to provide its new or revised SOL Methodology to one of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR	The Reliability Coordinator failed to provide its new or revised SOL Methodology to two of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR	The Reliability Coordinator failed to provide its new or revised SOL Methodology to ~~one~~three of the parties specified in ~~Parts 8.1 through 8.3.~~Requirement	The Reliability Coordinator failed to provide its new or revised SOL Methodology to ~~two~~four or more of the parties specified in ~~Parts 8.1 through 8.3.~~Requirement

	The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part ~~8.4~~9.1 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 Requirement R9, Part ~~8.4~~9.1, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	R9, Part 9.2 prior to the effective date OR The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part ~~8.4~~9.1, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	R9, Part 9.2 prior to the effective date 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.~~Requirement R9, Part 9.2 OR The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part ~~8.4~~9.1, 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 Requirement R9, Part ~~8.4~~9.1.

D. Regional Variances

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.	
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4		Project 2015-09 – Adopt revisions to standard.	Revisions

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

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
45-day formal comment period with initial ballot	09/29/17 – 11/14/17

Anticipated Actions	Date
45-day formal comment period with additional ballot	August 2018 – October 2018
10-day final ballot	October 2018
NERC Board adoption	November 2018

A. Introduction

1. **Title:** System Operating Limits Methodology for the Operations Horizon

2. **Number:** FAC-011-4

3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Reliability Coordinator

5. **Effective Date:** See Implementation Plan for Project 2015-09.

B. Requirements and Measures

R1. Each Reliability Coordinator shall have a documented methodology for establishing SOLs (i.e., SOL Methodology) within its Reliability Coordinator Area. *[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.

R2. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine which owner-provided Facility Ratings are to be used in operations such that the Transmission Operator and its Reliability Coordinator use common Facility Ratings. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. 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]*

3.1. Require that each BES bus/station have an associated System Voltage Limit, unless the Reliability Coordinators SOL Methodology specifically allows the exclusion of BES buses/stations from the requirement to have an associated System Voltage Limit;

3.2. Require that System Voltage Limits respect voltage-based Facility Ratings;

3.3. Require that System Voltage Limits are greater than or equal to in-service relay settings for under voltage load shedding systems and Undervoltage Load Shedding Programs;

3.4. Identify the lowest allowable System Voltage Limit;

3.5. Require the use of common System Voltage Limits between the Transmission Operator and its Reliability Coordinator and provide the method for determining the common System Voltage Limits to be used in operations;

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]*

4.1. Specify stability performance criteria, including any margins applied. The criteria shall, at a minimum, include the following:

4.1.1. steady-state voltage stability;

4.1.2. transient voltage response;

4.1.3. unit stability; and

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 stability limits are determined, 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 and other automatic post-Contingency mitigation actions in establishing stability limits used in operations.

4.7. State that the use of underfrequency load shedding (UFLS) programs and Undervoltage Load Shedding Programs are 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 identify in its SOL Methodology the Contingency events for use in determining stability limits and performing Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs) for the area under study. The SOL Methodology shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1. Specify the following 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; or
- single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

5.2. Identify any additional single or multiple Contingency events or types of Contingency events for use in performing Operational Planning Analysis and Real-time Assessments.

5.3. Identify any additional single or multiple Contingency events or types of Contingency events for use in determining stability limits.

5.4. Describe the method(s) for identifying which, if any, of the Contingency events provided by the Planning Coordinator or Transmission Planner in accordance with FAC-015-1, Requirement R4, to use in determining stability limits.

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, at a minimum, the following Bulk Electric System performance criteria: *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

6.1. The actual pre-Contingency state (Real-time monitoring and Real-time Assessment) and anticipated pre-Contingency state (Operational Planning Analysis) demonstrates the following:

6.1.1. Flow through Facilities are within Normal Ratings; however, Emergency Ratings may be used when System adjustments to return the flow within its Normal Rating could be executed and completed within the specified time duration of those Emergency Ratings.

6.1.2. Voltages are within normal System Voltage Limits; however, emergency System Voltage Limits may be used when System adjustments to return the voltage within its normal System Voltage Limits could be executed and completed within the specified time duration of those emergency System Voltage Limits.

6.1.3. Instability, Cascading or uncontrolled separation do not occur.

6.2. The evaluation of potential single Contingencies listed in Part 5.1.1 against the actual pre-Contingency state (Real-time monitoring and Real-time Assessments) and anticipated pre-Contingency state (Operational Planning Analysis) demonstrates the following:

6.2.1. Flow through Facilities are within applicable Emergency Ratings, provided that System adjustments could be executed and completed within the specified time duration of those Emergency Ratings. Flow through a Facility must not be above the Facility's highest Emergency Rating.

6.2.2. Voltages are within emergency System Voltage Limits.

6.2.3. Instability, Cascading or uncontrolled separation do not occur.

6.3. The evaluation of the potential Contingencies identified in Part 5.2 against the actual pre-Contingency state (Real-time monitoring and Real-time Assessments) and anticipated pre-Contingency state (Operational Planning Analysis) demonstrates that instability, Cascading, or uncontrolled separation does not occur.

6.4. The evaluation of the potential Contingencies identified in Part 5.3 demonstrates that instability does not occur.

6.5. In determining the System's response to any Contingency identified in Parts 5.1 through 5.3, planned load shedding is acceptable only after all other available System adjustments have been made.

M6. 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: *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

7.1. A description of how to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs).

7.2. Criteria for determining when violating a SOL qualifies as an IROL and criteria for developing any associated IROL T_V.

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 R6.

R8. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to communicate their established SOLs to the Reliability Coordinator. The method shall address the periodicity for communicating established SOLs. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M8. 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.

R9. Each Reliability Coordinator shall provide its SOL Methodology to: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

9.1. Each Reliability Coordinator that requests and indicates it has a reliability-related need within 30 days of a request.

9.2. Each of the following entities prior to the effective date of the SOL methodology:

9.2.1. Each adjacent Reliability Coordinator within the same Interconnection;

9.2.2. Each Planning Coordinator and Transmission Planner that is responsible for planning any portion of the Reliability Coordinator Area;

9.2.3. Each Transmission Operator within its Reliability Coordinator Area; and

9.2.4. Each Reliability Coordinator that has requested to receive updates and indicated it had a reliability-related need.

M9. Acceptable evidence that the Reliability Coordinator provided its SOL Methodology to the entities identified in Requirement R8 may include, but is not limited to, dated electronic or hard copy documentation such as emails with receipts, registered mail receipts, or postings to a secure web site with accompanying notification(s).

C. Compliance

1. Compliance Monitoring Process

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

1.2. Evidence Retention:

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

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

- The Reliability Coordinator shall keep data or evidence of compliance with Requirements R1 through R9 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.	N/A	N/A	N/A	The Reliability Coordinator did not have a SOL Methodology for establishing SOLs within its Reliability Coordinator Area.
R2.	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.
R3.	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.
R4.	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.
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.
R6.	The Reliability Coordinator failed to incorporate one of the Parts of Requirement R6 into its SOL Methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R6 into its SOL Methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R6 into its SOL Methodology.	The Reliability Coordinator failed to incorporate four of the Parts of Requirement R6 into its SOL Methodology.
R7.	N/A	N/A	The Reliability Coordinator failed to include Part 7.1 (a description of how to identify the subset of SOLs that qualify as IROLs) in its SOL Methodology.	The Reliability Coordinator failed to include Parts 7.1 and 7.2 in its SOL Methodology.

			OR The Reliability Coordinator failed to include Part 7.2 (a criteria for determining when violating a SOL qualifies as an IROL in its SOL Methodology. OR The Reliability Coordinator failed to include Part 7.2 (criteria for developing any associated IROL T_v) in its SOL Methodology.	
R8.	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.
R9.	The Reliability Coordinator failed to provide its new or revised SOL Methodology to one of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR	The Reliability Coordinator failed to provide its new or revised SOL Methodology to two of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR	The Reliability Coordinator failed to provide its new or revised SOL Methodology to three of the parties specified in Requirement R9, Part 9.2 prior to the effective date OR	The Reliability Coordinator failed to provide its new or revised SOL Methodology to four or more of the parties specified in Requirement R9, Part 9.2 prior to the effective date

	The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1 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 Requirement R9, Part 9.1, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	OR The Reliability Coordinator failed to provide its new or revised SOL Methodology to one or more of the parties specified in Requirement R9, Part 9.2 OR The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Requirement R9, Part 9.1, 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 Requirement R9, Part 9.1.

D. Regional Variances

None.

E. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board	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: FERC Order 705	Revised
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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

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 initial ballot	August 2018 – September 2018
10-day final ballot	September 2018
NERC Board adoption	November 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:** Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon

2. **Number:** FAC-013-32

3. **Purpose:** To ensure that Planning Coordinators have a methodology for, and perform an annual assessment to identify potential future Transmission System weaknesses and limiting Facilities that could impact the Bulk Electric System's (BES) ability to reliably transfer energy in the Near-Term Transmission Planning Horizon.

4. **Applicability:**

   4.1. Planning Coordinators

5. **Effective Date:**

See Implementation Plan for FAC-013-3.

B. Requirements and Measures

R1. Each Planning Coordinator shall have a documented methodology it uses to perform an annual assessment of Transfer Capability in the Near-Term Transmission Planning Horizon (Transfer Capability methodology). The Transfer Capability methodology shall include, at a minimum, the following information: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. Criteria for the selection of the transfers to be assessed.

1.2. Reserved for future use~~A statement that the assessment shall respect known System Operating Limits (SOLs)~~.

1.3. A statement that the assumptions and criteria used to perform the assessment are consistent with the Planning Coordinator's Planning~~planning~~ Assessments~~practices~~.

1.4. A description of how each of the following assumptions and criteria used in performing the assessment are addressed:

1.4.1. Generation dispatch, including but not limited to long term planned outages, additions and retirements.

1.4.2. Transmission system topology, including but not limited to long term planned Transmission outages, additions, and retirements.

1.4.3. System demand.

1.4.4. Current approved and projected Transmission uses.

1.4.5. Parallel path (loop flow) adjustments.

1.4.6. Contingencies

1.4.7. Monitored Facilities.

1.5. A description of how simulations of transfers are performed through the adjustment of generation, Load or both.

M1. Each Planning Coordinator shall have a Transfer Capability methodology that includes the information specified in Requirement R1.

R2. Each Planning Coordinator shall issue its Transfer Capability methodology, and any revisions to the Transfer Capability methodology, to the following entities subject to the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

2.1. Distribute to the following prior to the effectiveness of such revisions:

2.1.1. Each Planning Coordinator adjacent to the Planning Coordinator's Planning Coordinator area or overlapping the Planning Coordinator's area.

2.1.2. Each Transmission Planner within the Planning Coordinator's Planning Coordinator area.

2.2. Distribute to each functional entity that has a reliability-related need for the Transfer Capability methodology and submits a request for that methodology within 30 calendar days of receiving that written request.

M2. Each Planning Coordinator shall have evidence such as dated e-mail or dated transmittal letters that it provided the new or revised Transfer Capability methodology in accordance with Requirement R2

R3. If a recipient of the Transfer Capability methodology provides documented concerns with the methodology, the Planning Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the Transfer Capability methodology and, if no change will be made to that Transfer Capability methodology, the reason why. *[Violation Risk Factor: Lower][Time Horizon: Long-term Planning]* (Retirement approved by FERC effective January 21, 2014.)

M3. Each Planning Coordinator shall have evidence, such as dated e-mail or dated transmittal letters, that the Planning Coordinator provided a written response to that commenter in accordance with Requirement R3. (Retirement approved by FERC effective January 21, 2014.)

R4. During each calendar year, each Planning Coordinator shall conduct simulations and document an assessment based on those simulations in accordance with its Transfer Capability methodology for at least one year in the Near-Term Transmission Planning Horizon. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M4. Each Planning Coordinator shall have evidence such as dated assessment results, that it conducted and documented a Transfer Capability assessment in accordance with Requirement R4.

R5. Each Planning Coordinator shall make the documented Transfer Capability assessment results available within 45 calendar days of the completion of the assessment to the recipients of its Transfer Capability methodology pursuant to Requirement R2, Parts 2.1 and Part 2.2. However, if a functional entity that has a reliability related need for the results of the annual assessment of the Transfer Capabilities makes a written request for such an assessment after the completion of the assessment, the Planning Coordinator shall make the documented Transfer Capability assessment results available to that entity within 45 calendar days of receipt of the request *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M5. Each Planning Coordinator shall have evidence, such as dated copies of e-mails or transmittal letters, that it made its documented Transfer Capability assessment available to the entities in accordance with Requirement R5

R6. If a recipient of a documented Transfer Capability assessment requests data to support the assessment results, the Planning Coordinator shall provide such data to that entity within 45 calendar days of receipt of the request. The provision of such data shall be subject to the legal and regulatory obligations of the Planning Coordinator's area regarding the disclosure of confidential and/or sensitive information. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M6. Each Planning Coordinator shall have evidence, such as dated copies of e-mails or transmittal letters, that it made its documented Transfer Capability assessment data available 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 Planning Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Planning Coordinator shall have its current Transfer Capability methodology and any prior versions of the Transfer Capability methodology that were in force since the last compliance audit to show compliance with Requirement R1.
- The Planning Coordinator shall retain evidence since its last compliance audit to show compliance with Requirement R2.
- The Planning Coordinator shall retain evidence to show compliance with Requirements R3, R4, R5 and R6 for the most recent assessment. (R3 retired-Retirement approved by FERC effective January 21, 2014.)
- If a Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time periods specified above, whichever is longer.

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

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

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Planning Coordinator has a Transfer Capability methodology but failed to address one or two of the items listed in Requirement R1, Part 1.4.	The Planning Coordinator has a Transfer Capability methodology, but failed to incorporate one of the following Parts of Requirement R1 into that methodology: • Part 1.1 • ~~Part 1.2~~ • Part 1.3 • Part 1.5 OR The Planning Coordinator has a Transfer Capability methodology but failed to address three of the items listed in Requirement R1, Part 1.4.	The Planning Coordinator has a Transfer Capability methodology, but failed to incorporate two of the following Parts of Requirement R1 into that methodology: • Part 1.1 • ~~Part 1.2~~ • Part 1.3 • Part 1.5 OR The Planning Coordinator has a Transfer Capability methodology but failed to address four of the items listed in Requirement R1, Part 1.4.	The Planning Coordinator did not have a Transfer Capability methodology. OR The Planning Coordinator has a Transfer Capability methodology, but failed to incorporate three or more of the following Parts of Requirement R1 into that methodology: • Part 1.1 • ~~Part 1.2~~ • Part 1.3 • Part 1.5 OR The Planning Coordinator has a Transfer Capability methodology but failed to address more than four of the items listed in Requirement R1, Part 1.4.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R2.	The Planning Coordinator notified one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology after its implementation, but not more than 30 calendar days after its implementation. OR The Planning Coordinator provided the transfer Capability methodology more than 30 calendar days but not more than 60 calendar days after the receipt of a request.	The Planning Coordinator notified one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology more than 30 calendar days after its implementation, but not more than 60 calendar days after its implementation. OR The Planning Coordinator provided the Transfer Capability methodology more than 60 calendar days but not more than 90 calendar days after receipt of a request	The Planning Coordinator notified one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology more than 60 calendar days, but not more than 90 calendar days after its implementation. OR The Planning Coordinator provided the Transfer Capability methodology more than 90 calendar days but not more than 120 calendar days after receipt of a request.	The Planning Coordinator failed to notify one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology more than 90 calendar days after its implementation. OR The Planning Coordinator provided the Transfer Capability methodology more than 120 calendar days after receipt of a request.
R3. (Retirement approved by FERC effective	The Planning Coordinator provided a documented response to a documented concern with its Transfer Capability methodology as required in Requirement	The Planning Coordinator provided a documented response to a documented concern with its Transfer Capability methodology as required in Requirement	The Planning Coordinator provided a documented response to a documented concern with its Transfer Capability methodology as required in Requirement	The Planning Coordinator failed to provide a documented response to a documented concern with its Transfer Capability methodology as required in

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
January 21, 2013.)	R3 more than 45 calendar days, but not more than 60 calendar days after receipt of the concern.	R3 more than 60 calendar days, but not more than 75 calendar days after receipt of the concern.	R3 more than 75 calendar days, but not more than 90 calendar days after receipt of the concern.	Requirement R3 by more than 90 calendar days after receipt of the concern. OR The Planning Coordinator failed to respond to a documented concern with its Transfer Capability methodology.
R4.	The Planning Coordinator conducted a Transfer Capability assessment outside the calendar year, but not by more than 30 calendar days.	The Planning Coordinator conducted a Transfer Capability assessment outside the calendar year, by more than 30 calendar days, but not by more than 60 calendar days.	The Planning Coordinator conducted a Transfer Capability assessment outside the calendar year, by more than 60 calendar days, but not by more than 90 calendar days.	The Planning Coordinator failed to conduct a Transfer Capability assessment outside the calendar year by more than 90 calendar days. OR The Planning Coordinator failed to conduct a Transfer Capability assessment.
R5.	The Planning Coordinator made its documented Transfer Capability assessment available to one or more of the	The Planning Coordinator made its Transfer Capability assessment available to one or more of the recipients of its	The Planning Coordinator made its Transfer Capability assessment available to one or more of the recipients of its	The Planning Coordinator failed to make its documented Transfer Capability assessment available to one or more of

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	recipients of its Transfer Capability methodology more than 45 calendar days after the requirements of R5,, but not more than 60 calendar days after completion of the assessment.	Transfer Capability methodology more than 60 calendar days after the requirements of R5, but not more than 75 calendar days after completion of the assessment.	Transfer Capability methodology more than 75 calendar days after the requirements of R5, but not more than 90 days after completion of the assessment.	the recipients of its Transfer Capability methodology more than 90 days after the requirements of R5. OR The Planning Coordinator failed to make its documented Transfer Capability assessment available to any of the recipients of its Transfer Capability methodology under the requirements of R5.
R6.	The Planning Coordinator provided the requested data as required in Requirement R6 more than 45 calendar days after receipt of the request for data, but not more than 60 calendar days after the receipt of the request for data.	The Planning Coordinator provided the requested data as required in Requirement R6 more than 60 calendar days after receipt of the request for data, but not more than 75 calendar days after the receipt of the request for data.	The Planning Coordinator provided the requested data as required in Requirement R6 more than 75 calendar days after receipt of the request for data, but not more than 90 calendar days after the receipt of the request for data.	The Planning Coordinator provided the requested data as required in Requirement R6 more than 90 after the receipt of the request for data. OR The Planning Coordinator failed to provide the

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				requested data as required in Requirement R6.

D. Regional Variances

None.

E. Associated Documents

Link to the Implementation Plan and other important associated documents.

Version History

Version	Date	Action	Change Tracking
1	08/01/05	1. Changed incorrect use of certain hyphens (-) to "en dash (–)." 2. Lower cased the word "draft" and "drafting team" where appropriate. 3. Changed Anticipated Action #5, page 1, from "30-day" to "Thirty-day." Added or removed "periods."	01/20/05
2	01/24/11	Approved by BOT	
2	11/17/11	FERC Order issued approving FAC-013-2	
2	05/17/12	FERC Order issued directing the VRF's for Requirements R1. and R4. be changed from "Lower" to "Medium." FERC Order issued correcting the High and Severe VSL language for R1.	
2	02/7/13	R3 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	11/21/13	R3 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	

Rationale

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

Rationale for R1:
Text, text, text

Rationale for R2:
Text, text, text

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

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 initial ballot	August 2018 – September 2018
10-day final ballot	September 2018
NERC Board adoption	November 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:** Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon

2. **Number:** FAC-013-3

3. **Purpose:** To ensure that Planning Coordinators have a methodology for, and perform an annual assessment to identify potential future Transmission System weaknesses and limiting Facilities that could impact the Bulk Electric System's (BES) ability to reliably transfer energy in the Near-Term Transmission Planning Horizon.

4. **Applicability:**

   4.1. Planning Coordinators

5. **Effective Date:**

See Implementation Plan for FAC-013-3.

B. Requirements and Measures

R1. Each Planning Coordinator shall have a documented methodology it uses to perform an annual assessment of Transfer Capability in the Near-Term Transmission Planning Horizon (Transfer Capability methodology). The Transfer Capability methodology shall include, at a minimum, the following information: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. Criteria for the selection of the transfers to be assessed.

1.2. Reserved for future use.

1.3. A statement that the assumptions and criteria used to perform the assessment are consistent with the Planning Coordinator's Planning Assessments.

1.4. A description of how each of the following assumptions and criteria used in performing the assessment are addressed:

1.4.1. Generation dispatch, including but not limited to long term planned outages, additions and retirements.

1.4.2. Transmission system topology, including but not limited to long term planned Transmission outages, additions, and retirements.

1.4.3. System demand.

1.4.4. Current approved and projected Transmission uses.

1.4.5. Parallel path (loop flow) adjustments.

1.4.6. Contingencies

1.4.7. Monitored Facilities.

1.5. A description of how simulations of transfers are performed through the adjustment of generation, Load or both.

M1. Each Planning Coordinator shall have a Transfer Capability methodology that includes the information specified in Requirement R1.

R2. Each Planning Coordinator shall issue its Transfer Capability methodology, and any revisions to the Transfer Capability methodology, to the following entities subject to the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

2.1. Distribute to the following prior to the effectiveness of such revisions:

2.1.1. Each Planning Coordinator adjacent to the Planning Coordinator's Planning Coordinator area or overlapping the Planning Coordinator's area.

2.1.2. Each Transmission Planner within the Planning Coordinator's Planning Coordinator area.

2.2. Distribute to each functional entity that has a reliability-related need for the Transfer Capability methodology and submits a request for that methodology within 30 calendar days of receiving that written request.

M2. Each Planning Coordinator shall have evidence such as dated e-mail or dated transmittal letters that it provided the new or revised Transfer Capability methodology in accordance with Requirement R2

R3. If a recipient of the Transfer Capability methodology provides documented concerns with the methodology, the Planning Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the Transfer Capability methodology and, if no change will be made to that Transfer Capability methodology, the reason why. *[Violation Risk Factor: Lower][Time Horizon: Long-term Planning]* (Retirement approved by FERC effective January 21, 2014.)

M3. Each Planning Coordinator shall have evidence, such as dated e-mail or dated transmittal letters, that the Planning Coordinator provided a written response to that commenter in accordance with Requirement R3. (Retirement approved by FERC effective January 21, 2014.)

R4. During each calendar year, each Planning Coordinator shall conduct simulations and document an assessment based on those simulations in accordance with its Transfer Capability methodology for at least one year in the Near-Term Transmission Planning Horizon. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M4. Each Planning Coordinator shall have evidence such as dated assessment results, that it conducted and documented a Transfer Capability assessment in accordance with Requirement R4.

R5. Each Planning Coordinator shall make the documented Transfer Capability assessment results available within 45 calendar days of the completion of the assessment to the recipients of its Transfer Capability methodology pursuant to Requirement R2, Parts 2.1 and Part 2.2. However, if a functional entity that has a reliability related need for the results of the annual assessment of the Transfer Capabilities makes a written request for such an assessment after the completion of the assessment, the Planning Coordinator shall make the documented Transfer Capability assessment results available to that entity within 45 calendar days of receipt of the request *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M5. Each Planning Coordinator shall have evidence, such as dated copies of e-mails or transmittal letters, that it made its documented Transfer Capability assessment available to the entities in accordance with Requirement R5

R6. If a recipient of a documented Transfer Capability assessment requests data to support the assessment results, the Planning Coordinator shall provide such data to that entity within 45 calendar days of receipt of the request. The provision of such data shall be subject to the legal and regulatory obligations of the Planning Coordinator's area regarding the disclosure of confidential and/or sensitive information. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M6. Each Planning Coordinator shall have evidence, such as dated copies of e-mails or transmittal letters, that it made its documented Transfer Capability assessment data available 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 Planning Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Planning Coordinator shall have its current Transfer Capability methodology and any prior versions of the Transfer Capability methodology that were in force since the last compliance audit to show compliance with Requirement R1.
- The Planning Coordinator shall retain evidence since its last compliance audit to show compliance with Requirement R2.
- The Planning Coordinator shall retain evidence to show compliance with Requirements R3, R4, R5 and R6 for the most recent assessment. (R3 retired-Retirement approved by FERC effective January 21, 2014.)
- If a Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time periods specified above, whichever is longer.

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

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

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Planning Coordinator has a Transfer Capability methodology but failed to address one or two of the items listed in Requirement R1, Part 1.4.	The Planning Coordinator has a Transfer Capability methodology, but failed to incorporate one of the following Parts of Requirement R1 into that methodology: • Part 1.1 • Part 1.3 • Part 1.5 OR The Planning Coordinator has a Transfer Capability methodology but failed to address three of the items listed in Requirement R1, Part 1.4.	The Planning Coordinator has a Transfer Capability methodology, but failed to incorporate two of the following Parts of Requirement R1 into that methodology: • Part 1.1 • Part 1.3 • Part 1.5 OR The Planning Coordinator has a Transfer Capability methodology but failed to address four of the items listed in Requirement R1, Part 1.4.	The Planning Coordinator did not have a Transfer Capability methodology. OR The Planning Coordinator has a Transfer Capability methodology, but failed to incorporate three or more of the following Parts of Requirement R1 into that methodology: • Part 1.1 • Part 1.3 • Part 1.5 OR The Planning Coordinator has a Transfer Capability methodology but failed to address more than four of the items listed in Requirement R1, Part 1.4.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R2.	The Planning Coordinator notified one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology after its implementation, but not more than 30 calendar days after its implementation. OR The Planning Coordinator provided the transfer Capability methodology more than 30 calendar days but not more than 60 calendar days after the receipt of a request.	The Planning Coordinator notified one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology more than 30 calendar days after its implementation, but not more than 60 calendar days after its implementation. OR The Planning Coordinator provided the Transfer Capability methodology more than 60 calendar days but not more than 90 calendar days after receipt of a request	The Planning Coordinator notified one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology more than 60 calendar days, but not more than 90 calendar days after its implementation. OR The Planning Coordinator provided the Transfer Capability methodology more than 90 calendar days but not more than 120 calendar days after receipt of a request.	The Planning Coordinator failed to notify one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology more than 90 calendar days after its implementation. OR The Planning Coordinator provided the Transfer Capability methodology more than 120 calendar days after receipt of a request.
R3. (Retirement approved by FERC effective	The Planning Coordinator provided a documented response to a documented concern with its Transfer Capability methodology as required in Requirement	The Planning Coordinator provided a documented response to a documented concern with its Transfer Capability methodology as required in Requirement	The Planning Coordinator provided a documented response to a documented concern with its Transfer Capability methodology as required in Requirement	The Planning Coordinator failed to provide a documented response to a documented concern with its Transfer Capability methodology as required in

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
January 21, 2013.)	R3 more than 45 calendar days, but not more than 60 calendar days after receipt of the concern.	R3 more than 60 calendar days, but not more than 75 calendar days after receipt of the concern.	R3 more than 75 calendar days, but not more than 90 calendar days after receipt of the concern.	Requirement R3 by more than 90 calendar days after receipt of the concern. OR The Planning Coordinator failed to respond to a documented concern with its Transfer Capability methodology.
R4.	The Planning Coordinator conducted a Transfer Capability assessment outside the calendar year, but not by more than 30 calendar days.	The Planning Coordinator conducted a Transfer Capability assessment outside the calendar year, by more than 30 calendar days, but not by more than 60 calendar days.	The Planning Coordinator conducted a Transfer Capability assessment outside the calendar year, by more than 60 calendar days, but not by more than 90 calendar days.	The Planning Coordinator failed to conduct a Transfer Capability assessment outside the calendar year by more than 90 calendar days. OR The Planning Coordinator failed to conduct a Transfer Capability assessment.
R5.	The Planning Coordinator made its documented Transfer Capability assessment available to one or more of the	The Planning Coordinator made its Transfer Capability assessment available to one or more of the recipients of its	The Planning Coordinator made its Transfer Capability assessment available to one or more of the recipients of its	The Planning Coordinator failed to make its documented Transfer Capability assessment available to one or more of

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	recipients of its Transfer Capability methodology more than 45 calendar days after the requirements of R5,, but not more than 60 calendar days after completion of the assessment.	Transfer Capability methodology more than 60 calendar days after the requirements of R5, but not more than 75 calendar days after completion of the assessment.	Transfer Capability methodology more than 75 calendar days after the requirements of R5, but not more than 90 days after completion of the assessment.	the recipients of its Transfer Capability methodology more than 90 days after the requirements of R5. OR The Planning Coordinator failed to make its documented Transfer Capability assessment available to any of the recipients of its Transfer Capability methodology under the requirements of R5.
R6.	The Planning Coordinator provided the requested data as required in Requirement R6 more than 45 calendar days after receipt of the request for data, but not more than 60 calendar days after the receipt of the request for data.	The Planning Coordinator provided the requested data as required in Requirement R6 more than 60 calendar days after receipt of the request for data, but not more than 75 calendar days after the receipt of the request for data.	The Planning Coordinator provided the requested data as required in Requirement R6 more than 75 calendar days after receipt of the request for data, but not more than 90 calendar days after the receipt of the request for data.	The Planning Coordinator provided the requested data as required in Requirement R6 more than 90 after the receipt of the request for data. OR The Planning Coordinator failed to provide the

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				requested data as required in Requirement R6.

D. Regional Variances

None.

E. Associated Documents

Link to the Implementation Plan and other important associated documents.

Version History

Version	Date	Action	Change Tracking
1	08/01/05	1. Changed incorrect use of certain hyphens (-) to "en dash (–)." 2. Lower cased the word "draft" and "drafting team" where appropriate. 3. Changed Anticipated Action #5, page 1, from "30-day" to "Thirty-day." Added or removed "periods."	01/20/05
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2	02/7/13	R3 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	11/21/13	R3 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	

Rationale

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

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Text, text, text

Rationale for R2:
Text, text, text

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

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
45-day formal comment period with ballot	09/29/17 – 11/14/17

Anticipated Actions	Date
~~45-day formal comment period with ballot~~	~~September 2017 – October 2017~~
45-day formal comment period with additional ballot	~~January~~August 2018 – ~~February~~October 2018
10-day final ballot	~~February~~October 2018
NERC Board ~~(Board)~~ adoption	~~May~~November 2018

A. Introduction

1. **Title:** Establish and Communicate System Operating Limits

2. **Number:** FAC-014-3

3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Reliability Coordinator

   4.1.2. Transmission Operator

5. **Effective Date:** See Implementation Plan for Project 2015-09.

B. Requirements and Measures

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). *[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 demonstrates the Reliability Coordinator established IROLs in accordance with it 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. *[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 demonstrates the Transmission Operator established SOLs in accordance with its Reliability Coordinator's SOL Methodology.

R3. The Transmission Operator shall provide its 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. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation ~~to demonstrate~~ that demonstrates the Transmission Operator provided its SOLs 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. *[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 demonstrates 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, the 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);

5.2.5 A description of the associated system conditions; and

5.2.6 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 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.

M5. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation ~~to demonstrate that~~, posting to a secure website, or other electronic means, that demonstrates the Reliability Coordinator provided the information in accordance with Requirement R5.

R6. Each Transmission Operator and Reliability Coordinator ~~that is impacted by an IROL~~ shall ~~provide Transmission Owners and Generation Owners within its~~ use the Bulk Electric System performance criteria specified in the Reliability ~~Coordinator Area a list of Facilities owned by that entity that are critical~~Coordinator's SOL Methodology when performing OPAs, RTAs, and Real-time monitoring to ~~the derivation of the IROL.~~determine SOL exceedances. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

M6. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation ~~to demonstrate~~, that demonstrates the Transmission Operator and Reliability Coordinator ~~provided~~used the ~~list of Facilities~~Bulk Electric System performance criteria specified in ~~accordance with Requirement R6~~the Reliability Coordinator's SOL methodology when performing OPAs, RTAs and Real-Time Monitoring.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

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

1.2. Evidence Retention:

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

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

- The Reliability Coordinator or Transmission Operator shall keep data or evidence of Requirements R1 through ~~R6~~R8 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.	N/A	N/A	N/A	The Reliability Coordinator ~~did not~~failed to 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.
R2.	N/A	N/A	N/A	The Transmission Operator ~~did not~~failed to establish SOLs for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL Methodology.
R3.	N/A	N/A	The Transmission Operator provided its SOLs to its Reliability Coordinator, but ~~did not~~failed to provide its SOLs at the periodicity at which the RC needs such	The Transmission Operator ~~did not~~failed to provide its SOLs to its Reliability Coordinator.

			information to perform its reliability functions.	
R4.	N/A	N/A	N/A	The Reliability Coordinator ~~did not~~failed to 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.
R5.	The Reliability Coordinator ~~did not~~failed to provide one of the items listed in Requirement R5, Parts 5.1 through 5.~~5~~6.	The Reliability Coordinator ~~did not~~failed to provide two of the items listed in Requirement R5, Parts 5.1 through 5.~~5~~6.	The Reliability Coordinator ~~did not~~failed to provide three of the items listed in Requirement R5, Parts 5.1 through 5.~~5~~6.	The Reliability Coordinator ~~did not~~failed to provide four or more of the items listed in Requirement R5, Parts 5.1 through 5.~~5~~6.
R6.	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.~~A Transmission Operator or

				Reliability Coordinator failed to use the Bulk Electric System performance criteria specified in the Reliability Coordinator's SOL Methodology.

D. Regional Variances

None

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

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

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
45-day formal comment period with ballot	09/29/17 – 11/14/17

Anticipated Actions	Date
45-day formal comment period with additional ballot	August 2018 – October 2018
10-day final ballot	October 2018
NERC Board adoption	November 2018

A. Introduction

1. **Title:** Establish and Communicate System Operating Limits

2. **Number:** FAC-014-3

3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Reliability Coordinator

   4.1.2. Transmission Operator

5. **Effective Date:** See Implementation Plan for Project 2015-09.

B. Requirements and Measures

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). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation that demonstrates the Reliability Coordinator established IROLs in accordance with it 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. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation that demonstrates the Transmission Operator established SOLs in accordance with its Reliability Coordinator's SOL Methodology.

R3. The Transmission Operator shall provide its 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. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation that demonstrates the Transmission Operator provided its SOLs 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. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation that demonstrates 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, the 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 stability limit or IROL;

5.2.3 The associated IROL T_v for any IROL;

5.2.4 The associated Contingency(ies);

5.2.5 A description of the associated system conditions; and

5.2.6 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 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.

M5. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation, posting to a secure website, or other electronic means, that demonstrates the Reliability Coordinator provided the information in accordance with Requirement R5.

R6. Each Transmission Operator and Reliability Coordinator shall use the Bulk Electric System performance criteria specified in the Reliability Coordinator's SOL Methodology when performing OPAs, RTAs, and Real-time monitoring to determine SOL exceedances. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

M6. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation, that demonstrates the Transmission Operator and Reliability Coordinator used the Bulk Electric System performance criteria specified in the Reliability Coordinator's SOL methodology when performing OPAs, RTAs and Real-Time Monitoring.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

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

1.2. Evidence Retention:

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

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

- The Reliability Coordinator or Transmission Operator shall keep data or evidence of Requirements R1 through R8 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.	N/A	N/A	N/A	The Reliability Coordinator failed to 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.
R2.	N/A	N/A	N/A	The Transmission Operator failed to establish SOLs for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL Methodology.
R3.	N/A	N/A	The Transmission Operator provided its SOLs to its Reliability Coordinator, but failed to provide its SOLs at the periodicity at which the RC needs such information	The Transmission Operator failed to provide its SOLs to its Reliability Coordinator.

			to perform its reliability functions.	
R4.	N/A	N/A	N/A	The Reliability Coordinator failed to 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.
R5.	The Reliability Coordinator failed to provide one of the items listed in Requirement R5, Parts 5.1 through 5.6.	The Reliability Coordinator failed to provide two of the items listed in Requirement R5, Parts 5.1 through 5.6.	The Reliability Coordinator failed to provide three of the items listed in Requirement R5, Parts 5.1 through 5.6.	The Reliability Coordinator failed to provide four or more of the items listed in Requirement R5, Parts 5.1 through 5.6.
R6.	N/A	N/A	N/A	A Transmission Operator or Reliability Coordinator failed to use the Bulk Electric System performance criteria specified in the Reliability Coordinator's SOL Methodology.

D. Regional Variances

None

E. Interpretations

None

F. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board	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: 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

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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

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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 initial ballot	August 2018 – September 2018
10-day final ballot	September 2018
NERC Board adoption	November 2018

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements

2. **Number:** PRC-002-32

3. **Purpose:** To have adequate data available to facilitate analysis of Bulk Electric System (BES) Disturbances.

4. **Applicability:**

Functional Entities:

4.1 Reliability Coordinator~~The Responsible Entity is:~~

~~Eastern Interconnection – Planning Coordinator~~

~~**4.1.1 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~~

4.2 Transmission Owner

4.3 Generator Owner

5. **Effective Dates:** See Implementation Plan

B. Requirements and Measures

R1. Each Transmission Owner shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-2, Attachment 1.

1.2. Notify other owners of BES Elements connected to those BES buses, if any, within 90-calendar days of completion of Part 1.1, that those BES Elements require SER data and/or FR data.

1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the re-evaluated list of BES buses as per the Implementation Plan.

M1. The Transmission Owner has a dated (electronic or hard copy) list of BES buses for which SER and FR data is required, identified in accordance with PRC-002-2, Attachment 1, and evidence that all BES buses have been re-evaluated within the required intervals under Requirement R1. The Transmission Owner will also have

dated (electronic or hard copy) evidence that it notified other owners in accordance with Requirement R1.

R2. Each Transmission Owner and Generator Owner shall have SER data for circuit breaker position (open/close) for each circuit breaker it owns connected directly to the BES buses identified in Requirement R1 and associated with the BES Elements at those BES buses. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M2. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of SER data for circuit breaker position as specified in Requirement R2. Evidence may include, but is not limited to: (1) documents describing the device interconnections and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings; or (3) station drawings.

R3. Each Transmission Owner and Generator Owner shall have FR data to determine the following electrical quantities for each triggered FR for the BES Elements it owns connected to the BES buses identified in Requirement R1: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1 Phase-to-neutral voltage for each phase of each specified BES bus.

3.2 Each phase current and the residual or neutral current for the following BES Elements:

3.2.1 Transformers that have a low-side operating voltage of 100kV or above.

3.2.2 Transmission Lines.

M3. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of FR data that is sufficient to determine electrical quantities as specified in Requirement R3. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R4. Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R3 that meets the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

4.1 A single record or multiple records that include:

- A pre-trigger record length of at least two cycles and a total record length of at least 30-cycles for the same trigger point, or
- At least two cycles of the pre-trigger data, the first three cycles of the post-trigger data, and the final cycle of the fault as seen by the fault recorder.

4.2 A minimum recording rate of 16 samples per cycle.

4.3 Trigger settings for at least the following:

4.3.1 Neutral (residual) overcurrent.

4.3.2 Phase undervoltage or overcurrent.

M4. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that FR data meets Requirement R4. Evidence may include, but is not limited to: (1) documents describing the device specification (R4, Part 4.2) and device configuration or settings (R4, Parts 4.1 and 4.3), or (2) actual data recordings or derivations.

R5. Each Reliability Coordinator~~Responsible Entity~~ shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

5.1 Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following:

5.1.1 Generating resource(s) with:

5.1.1.1 Gross individual nameplate rating greater than or equal to 500 MVA.

5.1.1.2 Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1,000 MVA.

5.1.2 Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL).

5.1.3 Each terminal of a high voltage direct current (HVDC) circuit with a nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter.

5.1.4 One or more BES Elements that are part of an Interconnection Reliability Operating Limit (IROL).

5.1.5 Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program.

5.2 Identify a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least:

5.2.1 One BES Element; and

5.2.2 One BES Element per 3,000 MW of the Reliability Coordinator's~~Responsible Entity's~~ historical simultaneous peak System Demand.

5.3 Notify all owners of identified BES Elements, within 90-calendar days of completion of Part 5.1, that their respective BES Elements require DDR data when requested.

5.4 Re-evaluate all BES Elements at least once every five calendar years in accordance with Parts 5.1 and 5.2, and notify owners in accordance with Part 5.3 to implement the re-evaluated list of BES Elements as per the Implementation Plan.

M5. The Reliability Coordinator~~Responsible Entity~~ has a dated (electronic or hard copy) list of BES Elements for which DDR data is required, developed in accordance with Requirement R5, Part 5.1 and Part 5.2; and re-evaluated in accordance with Part 5.4. The Reliability Coordinator~~Responsible Entity~~ has dated evidence (electronic or hard copy) that each Transmission Owner or Generator Owner has been notified in accordance with Requirement 5, Part 5.3. Evidence may include, but is not limited to: letters, emails, electronic files, or hard copy records demonstrating transmittal of information.

R6. Each Transmission Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

6.1 One phase-to-neutral or positive sequence voltage.

6.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R6, Part 6.1, or the positive sequence current.

6.3 Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required.

6.4 Frequency of any one of the voltage(s) in Requirement R6, Part 6.1.

M6. The Transmission Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R6. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R7. Each Generator Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

7.1 One phase-to-neutral, phase-to-phase, or positive sequence voltage at either the generator step-up transformer (GSU) high-side or low-side voltage level.

7.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R7, Part 7.1, phase current(s) for any phase-to-phase voltages, or positive sequence current.

7.3 Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required.

7.4 Frequency of at least one of the voltages in Requirement R7, Part 7.1.

M7. The Generator Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R7. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for

common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R8. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have continuous data recording and storage. If the equipment was installed prior to the effective date of this standard and is not capable of continuous recording, triggered records must meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

8.1 Triggered record lengths of at least three minutes.

8.2 At least one of the following three triggers:

- Off nominal frequency trigger set at:

	Low	High
○ Eastern Interconnection	<59.75 Hz	>61.0 Hz
○ Western Interconnection	<59.55 Hz	>61.0 Hz
○ ERCOT Interconnection	<59.35 Hz	>61.0 Hz
○ Hydro-Quebec Interconnection	<58.55 Hz	>61.5 Hz

- Rate of change of frequency trigger set at:

○ Eastern Interconnection	< -0.03125 Hz/sec	> 0.125 Hz/sec
○ Western Interconnection	< -0.05625 Hz/sec	> 0.125 Hz/sec
○ ERCOT Interconnection	< -0.08125 Hz/sec	> 0.125 Hz/sec
○ Hydro-Quebec Interconnection	< -0.18125 Hz/sec	> 0.1875 Hz/sec

- Undervoltage trigger set no lower than 85 percent of normal operating voltage for a duration of 5 seconds.

M8. Each Transmission Owner and Generator Owner has dated evidence (electronic or hard copy) of data recordings and storage in accordance with Requirement R8. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings.

R9. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have DDR data that meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

9.1 Input sampling rate of at least 960 samples per second.

9.2 Output recording rate of electrical quantities of at least 30 times per second.

M9. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that DDR data meets Requirement R9. Evidence may include, but is not limited to: (1) documents describing the device specification, device configuration, or settings (R9, Part 9.1; R9, Part 9.2); or (2) actual data recordings (R9, Part 9.2).

R10. Each Transmission Owner and Generator Owner shall time synchronize all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

10.1 Synchronization to Coordinated Universal Time (UTC) with or without a local time offset.

10.2 Synchronized device clock accuracy within ± 2 milliseconds of UTC.

M10. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of time synchronization described in Requirement R10. Evidence may include, but is not limited to: (1) documents describing the device specification, configuration, or setting; (2) time synchronization indication or status; or 3) station drawings.

R11. Each Transmission Owner and Generator Owner shall provide, upon request, all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to the Reliability Coordinator~~Responsible Entity~~, Regional Entity, or NERC in accordance with the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

11.1 Data will be retrievable for the period of 10-calendar days, inclusive of the day the data was recorded.

11.2 Data subject to Part 11.1 will be provided within 30-calendar days of a request unless an extension is granted by the requestor.

11.3 SER data will be provided in ASCII Comma Separated Value (CSV) format following Attachment 2.

11.4 FR and DDR data will be provided in electronic files that are formatted in conformance with C37.111, (IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later.

11.5 Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.

M11. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that data was submitted upon request in accordance with Requirement R11. Evidence may include, but is not limited to: (1) dated transmittals to the requesting

entity with formatted records; (2) documents describing data storage capability, device specification, configuration or settings; or (3) actual data recordings.

R12. Each Transmission Owner and Generator Owner shall, within 90-calendar days of the discovery of a failure of the recording capability for the SER, FR or DDR data, either: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

- Restore the recording capability, or
- Submit a Corrective Action Plan (CAP) to the Regional Entity and implement it.

M12. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R12. Evidence may include, but is not limited to: (1) dated reports of discovery of a failure, (2) documentation noting the date the data recording was restored, (3) SCADA records, or (4) dated CAP transmittals to the Regional Entity and evidence that it implemented the CAP.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

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

The Transmission Owner, Generator Owner, ~~Planning Coordinator,~~ and Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner shall retain evidence of Requirement R1, Measure M1 for five calendar years.

The Transmission Owner shall retain evidence of Requirement R6, Measure M6 for three calendar years.

The Generator Owner shall retain evidence of Requirement R7, Measure M7 for three calendar years.

The Transmission Owner and Generator Owner shall retain evidence of requested data provided as per Requirements R2, R3, R4, R8, R9, R10, R11, and R12, Measures M2, M3, M4, M8, M9, M10, M11, and M12 for three calendar years.

The ~~Responsible Entity (Planning Coordinator or~~ Reliability Coordinator~~, as applicable)~~ shall retain evidence of Requirement R5, Measure M5 for five calendar years.

If a Transmission Owner, Generator Owner, or Reliability Coordinator ~~Responsible Entity~~ is found non-compliant, it shall keep information related to the non-compliance until mitigation is completed and approved or for the time specified above, whichever is longer.

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

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Lower	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 80 percent but less than 100 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by 30-calendar days or less. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 70 percent but less than or equal to 80 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 30-calendar days and less than or equal to 60-calendar days. OR The Transmission Owner as directed by Requirement R1, Part	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 60 percent but less than or equal to 70 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 60-calendar days and less than or equal to 90-calendar days. OR The Transmission Owner as directed by Requirement R1, Part	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for less than or equal to 60 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 90-calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying one or more other owners by

			owners by 10-calendar days or less.	1.2 was late in notifying the other owners by greater than 10-calendar days but less than or equal to 20-calendar days.	1.2 was late in notifying the other owners by greater than 20-calendar days but less than or equal to 30-calendar days.	greater than 30-calendar days.
R2	Long-term Planning	Lower	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 80 percent but less than 100 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 70 percent but less than or equal to 80 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 60 percent but less than or equal to 70 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 for less than or equal to 60 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.
R3	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 80 percent but less than 100 percent of the total set of required electrical	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 70 percent but less than or equal to 80 percent of the total set of required	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 60 percent but less than or equal to 70 percent of the total set of required	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers less than or equal to 60 percent of the total set of required electrical quantities,

			quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.
R4	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data that meets more than 80 percent but less than 100 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 70 percent but less than or equal to 80 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 60 percent but less than or equal to 70 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R4.
R5	Long-term Planning	Lower	The Reliability Coordinator ~~Responsible Entity~~ identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 80 percent but less than 100 percent of the	The ~~Responsible Entity~~ Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 70 percent but less than or equal to 80 percent of the	The Reliability Coordinator ~~Responsible Entity~~ identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 60 percent but less than or equal to 70 percent of the	The Reliability Coordinator ~~Responsible Entity~~ identified the BES Elements for which DDR data is required as directed by Requirement R5 for less than or equal to 60 percent of the

			required BES Elements included in Part 5.1. OR The ~~Responsible Entity~~Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by 30-calendar days or less. OR The ~~Responsible Entity~~Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners by 10-calendar days or less.	required BES Elements included in Part 5.1. OR The ~~Responsible Entity~~Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 30-calendar days and less than or equal to 60 -calendar days. OR The ~~Responsible Entity~~Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners by greater than 10-calendar days but less than or equal to 20-calendar days.	required BES Elements included in Part 5.1. OR The ~~Responsible Entity~~Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 60-calendar days and less than or equal to 90-calendar days. OR The ~~Responsible Entity~~Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners by greater than 20-calendar days but less than or equal to 30-calendar days.	required BES Elements included in Part 5.1. OR The ~~Responsible Entity~~Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 90-calendar days. OR The ~~Responsible Entity~~Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying one or more owners by greater than 30-calendar days. OR The ~~Responsible Entity~~Reliability Coordinator failed to ensure a minimum DDR coverage per Part 5.2.

R6	Long-term Planning	Lower	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 that covered more than 80 percent but less than 100 percent of the total required electrical quantities for all applicable BES Elements.	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 70 percent but less than or equal to 80 percent of the total required electrical quantities for all applicable BES Elements.	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 60 percent but less than or equal to 70 percent of the total required electrical quantities for all applicable BES Elements.	The Transmission Owner failed to have DDR data as directed by Requirement R6, Parts 6.1 through 6.4.
R7	Long-term Planning	Lower	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 that covers more than 80 percent but less than 100 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 70 percent but less than or equal to 80 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 60 percent but less than or equal to 70 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner failed to have DDR data as directed by Requirement R7, Parts 7.1 through 7.4.
R8	Long-term Planning	Lower	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed	The Transmission Owner or Generator Owner failed to have continuous or non-continuous DDR data,

			in Requirement R8, for more than 80 percent but less than 100 percent of the BES Elements they own as determined in Requirement R5.	in Requirement R8, for more than 70 percent but less than or equal to 80 percent of the BES Elements they own as determined in Requirement R5.	in Requirement R8, for more than 60 percent but less than or equal to 70 percent of the BES Elements they own as determined in Requirement R5.	as directed in Requirement R8, for the BES Elements they own as determined in Requirement R5.
R9	Long-term Planning	Lower	The Transmission Owner or Generator Owner had DDR data that meets more than 80 percent but less than 100 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 70 percent but less than or equal to 80 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 60 percent but less than or equal to 70 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R9.

R10	Long-term Planning	Lower	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 90 percent but less than 100 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 80 percent but less than or equal to 90 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 70 percent but less than or equal to 80 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner failed to have time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for less than or equal to 70 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.
R11	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 30-calendar days but less than 40-calendar days after the request unless an extension was granted	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 40-calendar days but less than or equal to 50-calendar days after the request unless an extension	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 50-calendar days but less than or equal to 60-calendar days after the request unless an extension	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 failed to provide the requested data more than 60-calendar days after the request unless an extension was granted by the requesting authority.

			by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 90 percent but less than 100 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 90 percent of the data but less than 100 percent of the data in the proper data format.	was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 80 percent but less than or equal to 90 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 80 percent of the data but less than or equal to 90 percent of the data in the proper data format.	was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 70 percent but less than or equal to 80 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 70 percent of the data but less than or equal to 80 percent of the data in the proper data format.	OR The Transmission Owner or Generator Owner as directed by Requirement R11 failed to provide less than or equal to 70 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided less than or equal to 70 percent of the data in the proper data format.
R12	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R12	The Transmission Owner or Generator Owner as directed by Requirement R12	The Transmission Owner or Generator Owner as directed by Requirement R12	The Transmission Owner or Generator Owner as directed by Requirement R12

			reported a failure and provided a Corrective Action Plan to the Regional Entity more than 90-calendar days but less than or equal to 100-calendar days after discovery of the failure.	reported a failure and provided a Corrective Action Plan to the Regional Entity more than 100-calendar days but less than or equal to 110-calendar days after discovery of the failure.	reported a failure and provided a Corrective Action Plan to the Regional Entity more than 110-calendar days but less than or equal to 120-calendar days after discovery of the failure. OR The Transmission Owner or Generator Owner as directed by Requirement R12 submitted a CAP to the Regional Entity but failed to implement it.	failed to report a failure and provide a Corrective Action Plan to the Regional Entity more than 120-calendar days after discovery of the failure. OR Transmission Owner or Generator Owner as directed by Requirement R12 failed to restore the recording capability and failed to submit a CAP to the Regional Entity.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

G. References

IEEE C37.111: Common format for transient data exchange (COMTRADE) for power Systems.

IEEE C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME). Standard published 11/09/2011 by IEEE.

NPCC SP6 Report Synchronized Event Data Reporting, revised March 31, 2005

U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations (2004).

U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout in the United States and Canada (Nov. 2003)

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
1	August 2, 2006	Adopted by NERC Board of Trustees	Revised
2	November 13, 2014	Adopted by NERC Board of Trustees	Revised under Project 2007-11 and merged with PRC-018-1.
2	September 24, 2015	FERC approved PRC-005-4. Docket No. RM15-4-000; Order No. 814	

Attachment 1

Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data

(Requirement R1)

To identify monitored BES buses for sequence of events recording (SER) and Fault recording (FR) data required by Requirement 1, each Transmission Owner shall follow sequentially, unless otherwise noted, the steps listed below:

Step 1. Determine a complete list of BES buses that it owns.

For the purposes of this standard, a single BES bus includes physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid. These buses may be modeled or represented by a single node in fault studies. For example, ring bus or breaker-and-a-half bus configurations are considered to be a single bus.

Step 2. Reduce the list to those BES buses that have a maximum available calculated three phase short circuit MVA of 1,500 MVA or greater. If there are no buses on the resulting list, proceed to Step 7.

Step 3. Determine the 11 BES buses on the list with the highest maximum available calculated three phase short circuit MVA level. If the list has 11 or fewer buses, proceed to Step 7.

Step 4. Calculate the median MVA level of the 11 BES buses determined in Step 3.

Step 5. Multiply the median MVA level determined in Step 4 by 20 percent.

Step 6. Reduce the BES buses on the list to only those that have a maximum available calculated three phase short circuit MVA higher than the greater of:

- 1,500 MVA or
- 20 percent of median MVA level determined in Step 5.

Step 7. If there are no BES buses on the list: the procedure is complete and no FR and SER data will be required. Proceed to Step 9.

If the list has 1 or more but less than or equal to 11 BES buses: FR and SER data is required at the BES bus with the highest maximum available calculated three phase short circuit MVA as determined in Step 3. Proceed to Step 9.

If the list has more than 11 BES buses: SER and FR data is required on at least the 10 percent of the BES buses determined in Step 6 with the highest maximum available calculated three phase short circuit MVA. Proceed to Step 8.

Step 8. SER and FR data is required at additional BES buses on the list determined in Step 6. The aggregate of the number of BES buses determined in Step 7 and this Step will be at least 20 percent of the BES buses determined in Step 6.

The additional BES buses are selected, at the Transmission Owner's discretion, to provide maximum wide-area coverage for SER and FR data. The following BES bus locations are recommended:

- Electrically distant buses or electrically distant from other DME devices.
- Voltage sensitive areas.
- Cohesive load and generation zones.
- BES buses with a relatively high number of incident Transmission circuits.
- BES buses with reactive power devices.
- Major Facilities interconnecting outside the Transmission Owner's area.

Step 9. The list of monitored BES buses for SER and FR data for Requirement R1 is the aggregate of the BES buses determined in Steps 7 and 8.

Attachment 2

Sequence of Events Recording (SER) Data Format

(Requirement R11, Part 11.3)

Date, Time, Local Time Code, Substation, Device, State[1]

08/27/13, 23:58:57.110, -5, Sub 1, Breaker 1, Close

08/27/13, 23:58:57.082, -5, Sub 2, Breaker 2, Close

08/27/13, 23:58:47.217, -5, Sub 1, Breaker 1, Open

08/27/13, 23:58:47.214, -5, Sub 2, Breaker 2, Open

[1] "OPEN" and "CLOSE" are used as examples. Other terminology such as TRIP, TRIP TO LOCKOUT, RECLOSE, etc. is also acceptable.

High Level Requirement Overview

Requirement	Entity	Identify BES Buses	Notification	SER	FR	5 Year Re-evaluation
R1	TO	X	X	X	X	X
R2	TO | GO			X		
R3	TO | GO				X	
R4	TO | GO				X	

Requirement	Entity	Identify BES Elements	Notification	DDR	5 Year Re-evaluation
R5	~~RE (PC |~~ RC~~)~~	X	X	X	X
R6	TO			X	
R7	GO			X	
R8	TO | GO			X	
R9	TO | GO			X	

Requirement	Entity	Time Synchronization	Provide SER, FR, DDR Data	SER, FR, DDR Availability
R10	TO | GO	X		
R11	TO | GO		X	
R12	TO | GO			X

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 Functional Entities:

~~When the term "Responsible Entity" is used in PRC-002-2, it specifically refers to those entities listed under 4.1. The Responsible Entity – the Planning Coordinator or~~Because the Reliability Coordinator~~, as applicable in each Interconnection –~~ has the best wide-area view of the BES, the Reliability Coordinator ~~and~~ is most suited to be responsible for determining the BES Elements for which dynamic Disturbance recording (DDR) data is required. The Transmission Owners and Generator Owners will have the responsibility for ensuring that adequate data is available for those BES Elements selected.

BES buses where sequence of events recording (SER) and fault recording (FR) data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their Systems to determine those buses. The Transmission Owners and Generator Owners that own BES Elements on those BES buses will have the responsibility for ensuring that adequate data is available.

Rationale for R1:

Analysis and reconstruction of BES events requires SER and FR data from key BES buses. Attachment 1 provides a uniform methodology to identify those BES buses. Repeated testing of the Attachment 1 methodology has demonstrated the proper distribution of SER and FR data collection. Review of actual BES short circuit data received from the industry in response to the DMSDT's data request (June 5, 2013 through July 5, 2013) illuminated a strong correlation between the available short circuit MVA at a Transmission bus and its relative size and importance to the BES based on (i) its voltage level, (ii) the number of Transmission Lines and other BES Elements connected to the BES bus, and (iii) the number and size of generating units connected to the bus. BES buses with a large short circuit MVA level are BES Elements that have a significant effect on System reliability and performance. Conversely, BES buses with very low short circuit MVA levels seldom cause wide-area or cascading System events, so SER and FR data from those BES Elements are not as significant. After analyzing and reviewing the collected data submittals from across the continent, the threshold MVA values were chosen to provide sufficient data for event analysis using engineering and operational judgment.

Concerns have existed that the defined methodology for bus selection will overly concentrate data to selected BES buses. For the purpose of PRC-002-2, there are a minimum number of BES buses for which SER and FR data is required based on the short circuit level. With these concepts and the objective being sufficient recording coverage for event analysis, the DMSDT developed the procedure in Attachment 1 that utilizes the maximum available calculated three phase short circuit MVA. This methodology ensures comparable and sufficient coverage for SER and FR data regardless of variations in the size and System topology of Transmission Owners across all Interconnections. Additionally, this methodology provides a degree of flexibility for the use of judgment in the selection process to ensure sufficient distribution.

BES buses where SER and FR data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their Systems to determine those buses.

Each Transmission Owner must re-evaluate the list of BES buses at least every five calendar years to address System changes since the previous evaluation. Changes to the BES do not mandate immediate inclusion of BES buses into the currently enforced list, but the list of BES buses will be re-evaluated at least every five calendar years to address System changes since the previous evaluation.

Since there may be multiple owners of equipment that comprise a BES bus, the notification required in R1 is necessary to ensure all owners are notified.

A 90-calendar day notification deadline provides adequate time for the Transmission Owner to make the appropriate determination and notification.

Rationale for R2:
The intent is to capture SER data for the status (open/close) of the circuit breakers that can interrupt the current flow through each BES Element connected to a BES bus. Change of state of circuit breaker position, time stamped according to Requirement R10 to a time synchronized clock, provides the basis for assembling the detailed sequence of events timeline of a power System Disturbance. Other status monitoring nomenclature can be used for devices other than circuit breakers.

Rationale for R3:
The required electrical quantities may either be directly measured or determinable if sufficient FR data is captured (e.g. residual or neutral current if the phase currents are directly measured). In order to cover all possible fault types, all BES bus phase-to-neutral voltages are required to be determinable for each BES bus identified in Requirement R1. BES bus voltage data is adequate for System Disturbance analysis. Phase current and residual current are required to distinguish between phase faults and ground faults. It also facilitates determination of the fault location and cause of relay operation. For transformers (Part 3.2.1), the data may be from either the high-side or the low-side of the transformer. Generator step-up transformers (GSUs) and leads 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 excluded from Requirement R3 because the fault current contribution from a generator to a fault on the Transmission System will be captured by FR data on the Transmission System, and Transmission System FR will capture faults on the generator interconnection.

Generator Owners may install this capability or, where the Transmission Owners already have suitable FR data, contract with the Transmission Owner. However, when required, the Generator Owner is still responsible for the provision of this data.

Rationale for R4:
Time stamped pre- and post-trigger fault data aid in the analysis of power System operations and determination if operations were as intended. System faults generally persist for a short time period, thus a 30-cycle total minimum record length is adequate. Multiple records allow for legacy microprocessor relays which, when time-synchronized, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30-contiguous cycles total.

A minimum recording rate of 16 samples per cycle (960 Hz) is required to get sufficient point on wave data for recreating accurate fault conditions.

Rationale for R5:
DDR is used for capturing the BES transient and post-transient response following Disturbances, and the data is used for event analysis and validating System performance. DDR plays a critical role in wide-area Disturbance analysis, and Requirement R5 ensures there is adequate wide-area coverage of DDR data for specific BES Elements to facilitate accurate and efficient event analysis. The Reliability Coordinator~~Responsible Entity~~ has the best wide-area view of the System and needs to ensure that there are sufficient BES Elements identified for DDR data capture. The identification of BES Elements requiring DDR data as per Requirement R5 is based upon industry experience with wide-area Disturbance analysis and the need for adequate data to facilitate event analysis. Ensuring data is captured for these BES Elements will significantly improve the accuracy of analysis and understanding of why an event occurred, not simply what occurred.

From its experience with changes to the Bulk Electric System that would affect DDR, the DMSDT decided that the five calendar year re-evaluation of the list is a reasonable interval for this review. Changes to the BES do not mandate immediate inclusion of BES Elements into the in force list, but the list of BES Elements will be re-evaluated at least every five calendar years to address System changes since the previous evaluation. However, this standard does not preclude the ~~Responsible Entity~~Reliability Coordinator from performing this re-evaluation more frequently to capture updated BES Elements.

~~The Responsible Entity, for the purposes of this standard, is defined as the PC or RC depending upon Interconnection, because they have the best overall perspective for determining wide-area DDR coverage. The Planning Coordinator and Reliability Coordinator assume different functions across the continent; therefore the Responsible Entity is defined in the Applicability Section and used throughout this standard.~~

The ~~Responsible Entity~~Reliability Coordinator must notify all owners of the selected BES Elements that DDR data is required for this standard. The ~~Responsible Entity~~Reliability Coordinator is only required to share the list of selected BES Elements that each Transmission Owner and Generator Owner respectively owns, not the entire list. This communication of selected BES Elements is required to ensure that the owners of the respective BES Elements are aware of their responsibilities under this standard.

Implementation of the monitoring equipment is the responsibility of the respective Transmission Owners and Generator Owners, the timeline for installing this capability is outlined in the Implementation Plan, and starts from notification of the list from the ~~Responsible Entity~~Reliability Coordinator. Data for each BES Element as defined by the ~~Responsible Entity~~Reliability Coordinator must be provided; however, this data can be either directly measured or accurately calculated. With the exception of HVDC circuits, DDR data is only required for one end or terminal of the BES Elements selected. For example, DDR data must be provided for at least one terminal of a Transmission Line or generator step-up (GSU) transformer, but not both terminals. For an interconnection between two ~~Responsible Entities~~Reliability Coordinators, each ~~Responsible Entity~~Reliability Coordinator will consider this interconnection independently, and are expected to work cooperatively to determine how to monitor the BES Elements that require DDR data. For an interconnection between two TO's, or a TO and a GO, the ~~Responsible Entity~~Reliability Coordinator will determine which entity will provide the data. The ~~Responsible Entity~~Reliability Coordinator will notify the owners that their BES Elements require DDR data.

Refer to the Guidelines and Technical Basis Section for more detail on the rationale and technical reasoning for each identified BES Element in Requirement R5, Part 5.1; monitoring these BES Elements with DDR will facilitate thorough and informative event analysis of wide-area Disturbances on the BES. Part 5.2 is included to ensure wide-area coverage across all ~~Responsible Entities~~Reliability Coordinators. It is intended that each ~~Responsible Entity~~Reliability Coordinator will have DDR data for one BES Element and at least one additional BES Element per 3,000 MW of its historical simultaneous peak System Demand.

Rationale for R6:
DDR is used to measure transient response to System Disturbances during a relatively balanced post-fault condition. Therefore, it is sufficient to provide a phase-to-neutral voltage or positive sequence voltage. The electrical quantities can be determined (calculated, derived, etc.).

Because all of the BES buses within a location are at the same frequency, one frequency measurement is adequate.

The data requirements for PRC-002-2 are based on a System configuration assuming all normally closed circuit breakers on a BES bus are closed.

Rationale for R7:
A crucial part of wide-area Disturbance analysis is understanding the dynamic response of generating resources. Therefore, it is necessary for Generator Owners to have DDR at either the high- or low-side of the generator step-up transformer (GSU) measuring the specified electrical quantities to adequately capture generator response. This standard defines the 'what' of DDR, not the 'how'. Generator Owners may install this capability or, where the Transmission Owners already have suitable DDR data, contract with the Transmission Owner. However, the Generator Owner is still responsible for the provision of this data.

Rationale for R8:

Large scale System outages generally are an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Data available pre- and post-contingency helps identify the causes and effects of each event leading to outages. Therefore, continuous recording and storage are necessary to ensure sufficient data is available for the entire event.
Existing DDR data recording across the BES may not record continuously. To accommodate its use for the purposes of this standard, triggered records are acceptable if the equipment was installed prior to the effective date of this standard. The frequency triggers are defined based on the dynamic response associated with each Interconnection. The undervoltage trigger is defined to capture possible delayed undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR).

Rationale for R9:
An input sampling rate of at least 960 samples per second, which corresponds to 16 samples per cycle on the input side of the DDR equipment, ensures adequate accuracy for calculation of recorded measurements such as complex voltage and frequency.
An output recording rate of electrical quantities of at least 30 times per second refers to the recording and measurement calculation rate of the device. Recorded measurements of at least 30 times per second provide adequate recording speed to monitor the low frequency oscillations typically of interest during power System Disturbances.

Rationale for R10:
Time synchronization of Disturbance monitoring data is essential for time alignment of large volumes of geographically dispersed records from diverse recording sources. Coordinated Universal Time (UTC) is a recognized time standard that utilizes atomic clocks for generating precision time measurements. All data must be provided in UTC formatted time either with or without the local time offset, expressed as a negative number (the difference between UTC and the local time zone where the measurements are recorded).
Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment. The equipment used to measure the electrical quantities must be time synchronized to ± 2 ms accuracy; however, accuracy of the application of this time stamp and therefore the accuracy of the data itself is not mandated. This is because of inherent delays associated with measuring the electrical quantities and events such as breaker closing, measurement transport delays, algorithm and measurement calculation techniques, etc. Ensuring that the monitoring devices internal clocks are within ± 2 ms accuracy will suffice with respect to providing time synchronized data.

Rationale for R11:
Wide-area Disturbance analysis includes data recording from many devices and entities. Standardized formatting and naming conventions of these files significantly improves timely analysis.

Providing the data within 30-calendar days (or the granted extension time), subject to Part 11.1, allows for reasonable time to collect the data and perform any necessary computations or formatting.

Data is required to be retrievable for 10-calendar days inclusive of the day the data was recorded, i.e. a 10-calendar day rolling window of available data. Data hold requests are usually initiated the same or next day following a major event for which data is requested. A 10-calendar day time frame provides a practical limit on the duration of data required to be stored and informs the requesting entities as to how long the data will be available. The requestor of data has to be aware of the Part 11.1 10-calendar day retrievability because requiring data retention for a longer period of time is expensive and unnecessary.

SER data shall be provided in a simple ASCII .CSV format as outlined in Attachment 2. Either equipment can provide the data or a simple conversion program can be used to convert files into this format. This will significantly improve the data format for event records, enabling the use of software tools for analyzing the SER data.

Part 11.4 specifies FR and DDR data files be provided in conformance with IEEE C37.111, IEEE Standard for Common Format for Transient Exchange (COMTRADE), revision 1999 or later. The use of IEEE C37.111-1999 or later is well established in the industry. C37.111-2013 is a version of COMTRADE that includes an annex describing the application of the COMTRADE standard to synchrophasor data; however, version C37.111-1999 is commonly used in the industry today.

Part 11.5 uses a standardized naming format, C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), for providing Disturbance monitoring data. This file format allows a streamlined analysis of large Disturbances, and includes critical records such as local time offset associated with the synchronization of the data.

Rationale for R12:
Each Transmission Owner and Generator Owner who owns equipment used for collecting the data required for this standard must repair any failures within 90-calendar days to ensure that adequate data is available for event analysis. If the Disturbance monitoring capability cannot be restored within 90-calendar days (e.g. budget cycle, service crews, vendors, needed outages, etc.), the entity must develop a Corrective Action Plan (CAP) for restoring the data recording capability. The timeline required for the CAP depends on the entity and the type of data required. It is treated as a failure if the recording capability is out of service for maintenance and/or testing for greater than 90-calendar days. An outage of the monitored BES Element does not constitute a failure of the Disturbance monitoring capability.

Guidelines and Technical Basis Section

Introduction

The emphasis of PRC-002-2 is not on how Disturbance monitoring data is captured, but what Bulk Electric System data is captured. There are a variety of ways to capture the data PRC-002-2 addresses, and existing and currently available equipment can meet the requirements of this standard. PRC-002-2 also addresses the importance of addressing the availability of Disturbance monitoring capability to ensure the completeness of BES data capture.

The data requirements for PRC-002-2 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

PRC-002-2 addresses "what" data is recorded, not "how" it is recorded.

Guideline for Requirement R1:

Sequence of events and fault recording for the analysis, reconstruction, and reporting of System Disturbances is important. However, SER and FR data is not required at every BES bus on the BES to conduct adequate or thorough analysis of a Disturbance. As major tools of event analysis, the time synchronized time stamp for a breaker change of state and the recorded waveforms of voltage and current for individual circuits allows the precise reconstruction of events of both localized and wide-area Disturbances.

More quality information is always better than less when performing event analysis. However, 100 percent coverage of all BES Elements is not practical nor required for effective analysis of wide-area Disturbances. Therefore, selectivity of required BES buses to monitor is important for the following reasons:

1. Identify key BES buses with breakers where crucial information is available when required.
2. Avoid excessive overlap of coverage.
3. Avoid gaps in critical coverage.
4. Provide coverage of BES Elements that could propagate a Disturbance.
5. Avoid mandates to cover BES Elements that are more likely to be a casualty of a Disturbance rather than a cause.
6. Establish selection criteria to provide effective coverage in different regions of the continent.

The major characteristics available to determine the selection process are:

1. System voltage level;
2. The number of Transmission Lines into a substation or switchyard;
3. The number and size of connected generating units;
4. The available short circuit levels.

Although it is straightforward to establish criteria for the application of identified BES buses, analysis was required to establish a sound technical basis to fulfill the required objectives.

To answer these questions and establish criteria for BES buses of SER and FR, the DMSDT established a sub-team referred to as the Monitored Value Analysis Team (MVA Team). The MVA Team collected information from a wide variety of Transmission Systems throughout the continent to analyze Transmission buses by the characteristics previously identified for the selection process.

The MVA Team learned that the development of criteria is not possible for adequate SER and FR coverage, based solely upon simple, bright line characteristics, such as the number of lines into a substation or switchyard at a particular voltage level or at a set level of short circuit current. To provide the appropriate coverage, a relatively simple but effective Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data was developed. This Procedure, included as Attachment 1, assists entities in fulfilling Requirement R1 of the standard.

The Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data is weighted to buses with higher short circuit levels. This is chosen for the following reasons:

1. The method is voltage level independent.
2. It is likely to select buses near large generation centers.
3. It is likely to select buses where delayed clearing can cause Cascading.
4. Selected buses directly correlate to the Universal Power Transfer equation: Lower Impedance – increased power flows – greater System impact.

To perform the calculations of Attachment 1, the following information below is required and the following steps (provided in summary form) are required for Systems with more than 11 BES buses with three phase short circuit levels above 1,500 MVA.

1. Total number of BES buses in the Transmission System under evaluation.
   a. Only tangible substation or switchyard buses are included.
   b. Pseudo buses created for analysis purposes in System models are excluded.
2. Determine the three phase short circuit MVA for each BES bus.
3. Exclude BES buses from the list with short circuit levels below 1,500 MVA.
4. Determine the median short circuit for the top 11 BES buses on the list (position number 6).
5. Multiply median short circuit level by 20 percent.
6. Reduce the list of BES buses to those with short circuit levels higher than 20 percent of the median.
7. Apply SER and FR at BES buses with short circuit levels in the top 10 percent of the list (from 6).

8. Apply SER and FR at BES buses at an additional 10 percent of the list using engineering judgment, and allowing flexibility to factor in the following considerations:
   - Electrically distant BES buses or electrically distant from other DME devices
   - Voltage sensitive areas
   - Cohesive load and generation zones
   - BES buses with a relatively high number of incident Transmission circuits
   - BES buses with reactive power devices
   - Major facilities interconnecting outside the Transmission Owner's area.

For event analysis purposes, more valuable information is attained about generators and their response to System events pre- and post-contingency through DDR data versus SER or FR records. SER data of the opening of the primary generator output interrupting devices (e.g. synchronizing breaker) may not reliably indicate the actual time that a generator tripped; for instance, when it trips on reverse power after loss of its prime mover (e.g. combustion or steam turbine). As a result, this standard only requires DDR data.

The re-evaluation interval of five years was chosen based on the experience of the DMSDT to address changing System configurations while creating balance in the frequency of re-evaluations.

Guideline for Requirement R2:

Analyses of wide-area Disturbances often begin by evaluation of SERs to help determine the initiating event(s) and follow the Disturbance propagation. Recording of breaker operations help determine the interruption of line flows while generator loading is best determined by DDR data, since generator loading can be essentially zero regardless of breaker position. However, generator breakers directly connected to an identified BES bus are required to have SER data captured. It is important in event analysis to know when a BES bus is cleared regardless of a generator's loading.

Generator Owners are included in this requirement because a Generator Owner may, in some instances, own breakers directly connected to the Transmission Owner's BES bus.

Guideline for Requirement R3:

The BES buses for which FR data is required are determined based on the methodology described in Attachment 1 of the standard. The BES Elements connected to those BES buses for which FR data is required include:

- Transformers with a low-side operating voltage of 100kV or above
- Transmission Lines

Only those BES Elements that are identified as BES as defined in the latest in effect NERC definition are to be monitored. For example, radial lines or transformers with low-side voltage less than 100kV are not included.

FR data must be determinable from each terminal of a BES Element connected to applicable BES buses.

Generator step-up transformers (GSU) are excluded from the above based on the following:

- Current contribution from a generator in case of fault on the Transmission System will be captured by FR data on the Transmission System.
- For faults on the interconnection to generating facilities it is sufficient to have fault current data from the Transmission station end of the interconnection. Current contribution from a generator can be readily calculated if needed.

The DMSDT, after consulting with NERC's Event Analysis group, determined that DDR data from selected generator locations was more important for event analysis than FR data.

Recording of Electrical Quantities

For effective fault analysis it is necessary to know values of all phase and neutral currents and all phase-to-neutral voltages. Based on such FR data it is possible to determine all fault types. FR data also augments SERs in evaluating circuit breaker operation.

Current Recordings

The required electrical quantities are normally directly measured. Certain quantities can be derived if sufficient data is measured, for example residual or neutral currents.
Since a Transmission System is generally well balanced, with phase currents having essentially similar magnitudes and phase angle differences of 120°, during normal conditions there is negligible neutral (residual) current. In case of a ground fault the resulting phase current imbalance produces residual current that can be either measured or calculated.

Neutral current, also known as ground or residual current $\mathbf{I}_r$, is calculated as a sum of vectors of three phase currents:

$\mathbf{I}_r = 3 \bullet \mathbf{I}_0 = \mathbf{I}_A + \mathbf{I}_B + \mathbf{I}_C$

$\mathbf{I}_0$ - Zero-sequence current

$\mathbf{I}_A$, $\mathbf{I}_B$, $\mathbf{I}_C$ - Phase current (vectors)

Another example of how required electrical quantities can be derived is based on Kirchhoff's Law. Fault currents for one of the BES Elements connected to a particular BES bus can be derived as a vectorial sum of fault currents recorded at the other BES Elements connected to that BES bus.

Voltage Recordings

Voltages are to be recorded or accurately determined at applicable BES buses.

Guideline for Requirement R4:

Pre- and post-trigger fault data along with the SER breaker data, all time stamped to a common clock at millisecond accuracy, aid in the analysis of protection System operations after a fault to determine if a protection System operated as designed. Generally speaking, BES faults persist for a very short time period, approximately 1 to 30 cycles, thus a 30-cycle record length provides adequate data. Multiple records allow for legacy microprocessor relays which, when time synchronized to a common clock, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30-contiguous cycles total.

A minimum recording rate of 16 samples per cycle is required to get accurate waveforms and to get 1 millisecond resolution for any digital input which may be used for FR.

FR triggers can be set so that when the monitored value on the recording device goes above or below the trigger value, data is recorded. Requirement R4, sub-Part 4.3.1 specifies a neutral (residual) overcurrent trigger for ground faults. Requirement R4, sub-Part 4.3.2 specifies a phase undervoltage or overcurrent trigger for phase-to-phase faults.

Guideline for Requirement R5:

DDR data is used for wide-area Disturbance monitoring to determine the System's electromechanical transient and post-transient response and validate System model performance. DDR is typically located based on strategic studies which include angular, frequency, voltage, and oscillation stability. However, for adequately monitoring the System's dynamic response and ensuring sufficient coverage to determine System performance, DDR is required for key BES Elements in addition to a minimum requirement of DDR coverage.

Each ~~Responsible Entity~~Reliability Coordinator ~~(PC or RC)~~ is required to identify sufficient DDR data capture for, at a minimum, one BES Element and then one additional BES Element per 3,000 MW of historical simultaneous peak System Demand. This DDR data is included to provide adequate System wide coverage across an Interconnection. To clarify, if any of the key BES Elements requiring DDR monitoring are within the ~~Responsible Entity's~~Reliability Coordinator ~~a~~Area, DDR data capability is required. If a ~~Responsible Entity~~Reliability Coordinator ~~(PC or RC)~~ does not meet the requirements of Part 5.1, additional coverage had to be specified.

Loss of large generating resources poses a frequency and angular stability risk for all Interconnections across North America. Data capturing the dynamic response of these machines during a Disturbance helps the analysis of large Disturbances. Having data regarding generator dynamic response to Disturbances greatly improves understanding of ***why*** an event occurs rather than what occurred. To determine and provide the basis for unit size criteria, the DMSDT acquired specific generating unit data from NERC's Generating Availability Data System (GADS) program. The data contained generating unit size information for each generating unit in North America which was reported in 2013 to the NERC GADS program. The DMSDT analyzed

the spreadsheet data to determine: (i) how many units were above or below selected size thresholds; and (ii) the aggregate sum of the ratings of the units within the boundaries of those thresholds. Statistical information about this data was then produced, i.e. averages, means and percentages. The DMSDT determined the following basic information about the generating units of interest (current North America fleet, i.e. units reporting in 2013) included in the spreadsheet:

- The number of individual generating units in total included in the spreadsheet.
- The number of individual generating units rated at 20 MW or larger included in the spreadsheet. These units would generally require that their owners be registered as GOs in the NERC CMEP.
- The total number of units within selected size boundaries.
- The aggregate sum of ratings, in MWs, of the units within the boundaries of those thresholds.

The information in the spreadsheet does not provide information by which the plant information location of each unit can be determined, i.e. the DMSDT could not use the information to determine which units were located together at a given generation site or facility.

From this information, the DMSDT was able to reasonably speculate the generating unit size thresholds proposed in Requirement R5, sub-Part 5.1.1 of the standard. Generating resources intended for DDR data recording are those individual units with gross nameplate ratings "greater than or equal to 500 MVA". The 500 MVA individual unit size threshold was selected because this number roughly accounts for 47 percent of the generating capacity in NERC footprint while only requiring DDR coverage on about 12.5 percent of the generating units. As mentioned, there was no data pertaining to unit location for aggregating plant/facility sizes. However, Requirement R5, sub-Part 5.1.1 is included to capture larger units located at large generating plants which could pose a stability risk to the System if multiple large units were lost due to electrical or non-electrical contingencies. For generating plants, each individual generator at the plant/facility with a gross nameplate rating greater than or equal to 300 MVA must have DDR where the gross nameplate rating of the plant/facility is greater than or equal to 1,000 MVA. The 300 MVA threshold was chosen based on the DMSDT's judgment and experience. The incremental impact to the number of units requiring monitoring is expected to be relatively low. For combined cycle plants where only one generator has a rating greater than or equal to 300MVA, that is the only generator that would need DDR.

Permanent System Operating Limits (SOLs) are used to operate the System within reliable and secure limits. In particular, SOLs related to angular or voltage stability have a significant impact on BES reliability and performance. Therefore, at least one BES Element of an SOL should be monitored.

The draft standard requires "One or more BES Elements that are part of an Interconnection Reliability Operating Limits (IROLs)." Interconnection Reliability Operating Limits (IROLs) are included because the risk of violating these limits poses a risk to System stability and the

potential for cascading outages. IROLs may be defined by a single or multiple monitored BES Element(s) and contingent BES Element(s). The standard does not dictate selection of the contingent and/or monitored BES Elements. Rather the Drafting Team believes this determination is best made by the ~~Responsible Entity~~Reliability Coordinator for each IROL considered based on the severity of violating this IROL.

Locations where an undervoltage load shedding (UVLS) program is deployed are prone to voltage instability since they are generally areas of significant Demand. The ~~Responsible Entity~~Reliability Coordinator ~~(PC or RC)~~ will identify these areas where a UVLS is in service and identify a useful and effective BES Element to monitor for DDR such that action of the UVLS or voltage instability on the BES could be captured. For example, a major 500kV or 230kV substation on the EHV System close to the load pocket where the UVLS is deployed would likely be a valuable electrical location for DDR coverage and would aid in post-Disturbance analysis of the load area's response to large System excursions (voltage, frequency, etc.).

Guideline for Requirement R6:

DDR data shows transient response to System Disturbances after a fault is cleared (post-fault), under a relatively balanced operating condition. Therefore, it is sufficient to provide a single phase-to-neutral voltage or positive sequence voltage. Recording of all three phases of a circuit is not required, although this may be used to compute and record the positive sequence voltage.

The bus where a voltage measurement is required is based on the list of BES Elements defined by the ~~Responsible Entity~~Reliability Coordinator ~~(PC or RC)~~ in Requirement R5. The intent of the standard is not to require a separate voltage measurement of each BES Element where a common bus voltage measurement is available. For example, a breaker-and-a-half or double-bus configuration with a North (or East) Bus and South (or West) Bus, would require both buses to have voltage recording because either can be taken out of service indefinitely with the targeted BES Element remaining in service. This may be accomplished either by recording both bus voltages separately, or by providing a selector switch to connect either of the bus voltage sources to a single recording input of the DDR device. This component of the requirement is therefore included to mitigate the potential of failed frequency, phase angle, real power, and reactive power calculations due to voltage measurements removed from service while sufficient voltage measurement is actually available during these operating conditions.

It must be emphasized that the data requirements for PRC-002-2 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

When current recording is required, it should be on the same phase as the voltage recording taken at the location if a single phase-to-neutral voltage is provided. Positive sequence current recording is also acceptable.

For all circuits where current recording is required, Real and Reactive Power will be recorded on a three phase basis. These recordings may be derived either from phase quantities or from positive sequence quantities.

Guideline for Requirement R7:

All Guidelines specified for Requirement R6 apply to Requirement R7. Since either the high- or low-side windings of the generator step-up transformer (GSU) may be connected in delta, phase-to-phase voltage recording is an acceptable voltage recording. As was explained in the Guideline for Requirement R6, the BES is operating under a relatively balanced operating condition and, if needed, phase-to-neutral quantities can be derived from phase-to-phase quantities.

Again it must be emphasized that the data requirements for PRC-002-2 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

Guideline for Requirement R8:

Wide-area System outages are generally an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Pre- and post-contingency data helps identify the causes and effects of each event leading to the outages. This drives a need for continuous recording and storage to ensure sufficient data is available for the entire Disturbance.

Transmission Owners and Generator Owners are required to have continuous DDR for the BES Elements identified in Requirement R6. However, this requirement recognizes that legacy equipment may exist for some BES Elements that do not have continuous data recording capabilities. For equipment that was installed prior to the effective date of the standard, triggered DDR records of three minutes are acceptable using at least one of the trigger types specified in Requirement R8, Part 8.2:

- Off nominal frequency triggers are used to capture high- or low-frequency excursions of significant size based on the Interconnection size and inertia.
- Rate of change of frequency triggers are used to capture major changes in System frequency which could be caused by large changes in generation or load, or possibly changes in System impedance.
- The undervoltage trigger specified in this standard is provided to capture possible sustained undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR) events. A sustained voltage of 85 percent is outside normal schedule operating voltages and is sufficiently low to capture abnormal voltage conditions on the BES.

Guideline for Requirement R9:

DDR data contains the dynamic response of a power System to a Disturbance and is used for analyzing complex power System events. This recording is typically used to capture short-term

and long-term Disturbances, such as a power swing. Since the data of interest is changing over time, DDR data is normally stored in the form of RMS values or phasor values, as opposed to directly sampled data as found in FR data.

The issue of the sampling rate used in a recording instrument is quite important for at least two reasons: the anti-aliasing filter selection and accuracy of signal representation. The anti-aliasing filter selection is associated with the requirement of a sampling rate at least twice the highest frequency of a sampled signal. At the same time, the accuracy of signal representation is also dependent on the selection of the sampling rate. In general, the higher the sampling rate, the better the representation. In the abnormal conditions of interest (e.g. faults or other Disturbances); the input signal may contain frequencies in the range of 0-400 Hz. Hence, the rate of 960 samples per second (16 samples/cycle) is considered an adequate sampling rate that satisfies the input signal requirements.

In general, dynamic events of interest are: inter-area oscillations, local generator oscillations, wind turbine generator torsional modes, HVDC control modes, exciter control modes, and steam turbine torsional modes. Their frequencies range from 0.1-20 Hz. In order to reconstruct these dynamic events, a minimum recording time of 30 times per second is required.

Guideline for Requirement R10: Time synchronization of Disturbance monitoring data allows for the time alignment of large volumes of geographically dispersed data records from diverse recording sources. A universally recognized time standard is necessary to provide the foundation for this alignment. Coordinated Universal Time (UTC) is the foundation used for the time alignment of records. It is an international time standard utilizing atomic clocks for generating precision time measurements at fractions of a second levels. The local time offset, expressed as a negative number, is the difference between UTC and the local time zone where the measurements are recorded.

Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment.

Time synchronization accuracy is specified in response to Recommendation 12b in the NERC August, 2003, Blackout Final NERC Report Section V Conclusions and Recommendations:

“Recommendation 12b: Facilities owners shall, in accordance with regional criteria, upgrade existing dynamic recorders to include GPS time synchronization…”

Also, from the U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout, November 2003, in the United States and Canada, page 103:

“Establishing a precise and accurate sequence of outage-related events was a critical building block for the other parts of the investigation. One of the key problems in developing this sequence was that although much of the data pertinent to an event was time-stamped, there was some variance from source to source in how the time-stamping was done, and not all of the time-stamps were synchronized…”

From NPCC's SP6 Report Synchronized Event Data Reporting, revised March 31, 2005, the investigation by the authoring working group revealed that existing GPS receivers can be expected to provide a time code output which has an uncertainty on the order of 1 millisecond, uncertainty being a quantitative descriptor.

Guideline for Requirement R11:

This requirement directs the applicable entities, upon requests from the ~~Responsible Entity~~Reliability Coordinator, Regional Entity or NERC, to provide SER and FR data for BES buses determined in Requirement R1 and DDR data for BES Elements determined as per Requirement R5. To facilitate the analysis of BES Disturbances, it is important that the data is provided to the requestor within a reasonable period of time.

Requirement R11, Part 11.1 specifies the maximum time frame of 30-calendar days to provide the data. Thirty calendar days is a reasonable time frame to allow for the collection of data, and submission to the requestor. An entity may request an extension of the 30-day submission requirement. If granted by the requestor, the entity must submit the data within the approved extended time.

Requirement R11, Part 11.2 specifies that the minimum time period of 10-calendar days inclusive of the day the data was recorded for which the data will be retrievable. With the equipment in use that has the capability of recording data, having the data retrievable for the 10-calendar days is realistic and doable. It is important to note that applicable entities should account for any expected delays in retrieving data and this may require devices to have data available for more than 10 days. To clarify the 10-calendar day time frame, an incident occurs on Day 1. If a request for data is made on Day 6, then that data has to be provided to the requestor within 30-calendar days after a request or a granted time extension. However, if a request for the data is made on Day 11, that is outside the 10-calendar days specified in the requirement, and an entity would not be out of compliance if it did not have the data.

Requirement R11, Part 11.3 specifies a Comma Separated Value (CSV) format according to Attachment 2 for the SER data. It is necessary to establish a standard format as it will be incorporated with other submitted data to provide a detailed sequence of events timeline of a power System Disturbance.

Requirement R11, Part 11.4 specifies the IEEE C37.111 COMTRADE format for the FR and DDR data. The IEEE C37.111 is the Standard for Common Format for Transient Data Exchange and is well established in the industry. It is necessary to specify a standard format as multiple submissions of data from many sources will be incorporated to provide a detailed analysis of a power System Disturbance. The latest revision of COMTRADE (C37.111-2013) includes an annex describing the application of the COMTRADE standard to synchophasor data.

Requirement R11, Part 11.5 specifies the IEEE C37.232 COMNAME format for naming the data files of the SER, FR and DDR. The IEEE C37.232 is the Standard for Common Format for Naming Time Sequence Data Files. The first version was approved in 2007. From the August 14, 2003 blackout there were thousands of Fault Recording data files collected. The collected data files

did not have a common naming convention and it was therefore difficult to discern which files came from which utilities and which ones were captured by which devices. The lack of a common naming practice seriously hindered the investigation process. Subsequently, and in its initial report on the blackout, NERC stressed the need for having a common naming practice and listed it as one of its top ten recommendations.

Guideline for Requirement R12:

This requirement directs the respective owners of Transmission and Generator equipment to be alert to the proper functioning of equipment used for SER, FR, and DDR data capabilities for the BES buses and BES Elements, which were established in Requirements R1 and R5. The owners are to restore the capability within 90-calendar days of discovery of a failure. This requirement is structured to recognize that the existence of a "reasonable" amount of capability out-of-service does not result in lack of sufficient data for coverage of the System. Furthermore, 90-calendar days is typically sufficient time for repair or maintenance to be performed. However, in recognition of the fact that there may be occasions for which it is not possible to restore the capability within 90-calendar days, the requirement further provides that, for such cases, the entity submit a Corrective Action Plan (CAP) to the Regional Entity and implement it. These actions are considered to be appropriate to provide for robust and adequate data availability.

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 initial ballot	August 2018 – September 2018
10-day final ballot	September 2018
NERC Board adoption	November 2018

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements

2. **Number:** PRC-002-3

3. **Purpose:** To have adequate data available to facilitate analysis of Bulk Electric System (BES) Disturbances.

4. **Applicability:**

   Functional Entities:

   4.1 Reliability Coordinator

   4.2 Transmission Owner

   4.3 Generator Owner

5. **Effective Dates:** See Implementation Plan

B. Requirements and Measures

R1. Each Transmission Owner shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-2, Attachment 1.

1.2. Notify other owners of BES Elements connected to those BES buses, if any, within 90-calendar days of completion of Part 1.1, that those BES Elements require SER data and/or FR data.

1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the re-evaluated list of BES buses as per the Implementation Plan.

M1. The Transmission Owner has a dated (electronic or hard copy) list of BES buses for which SER and FR data is required, identified in accordance with PRC-002-2, Attachment 1, and evidence that all BES buses have been re-evaluated within the required intervals under Requirement R1. The Transmission Owner will also have dated (electronic or hard copy) evidence that it notified other owners in accordance with Requirement R1.

R2. Each Transmission Owner and Generator Owner shall have SER data for circuit breaker position (open/close) for each circuit breaker it owns connected directly to the BES buses identified in Requirement R1 and associated with the BES Elements at those BES buses. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M2. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of SER data for circuit breaker position as specified in Requirement R2. Evidence may include, but is not limited to: (1) documents describing the device interconnections and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings; or (3) station drawings.

R3. Each Transmission Owner and Generator Owner shall have FR data to determine the following electrical quantities for each triggered FR for the BES Elements it owns connected to the BES buses identified in Requirement R1: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1 Phase-to-neutral voltage for each phase of each specified BES bus.

3.2 Each phase current and the residual or neutral current for the following BES Elements:

3.2.1 Transformers that have a low-side operating voltage of 100kV or above.

3.2.2 Transmission Lines.

M3. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of FR data that is sufficient to determine electrical quantities as specified in Requirement R3. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R4. Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R3 that meets the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

4.1 A single record or multiple records that include:

- A pre-trigger record length of at least two cycles and a total record length of at least 30-cycles for the same trigger point, or
- At least two cycles of the pre-trigger data, the first three cycles of the post-trigger data, and the final cycle of the fault as seen by the fault recorder.

4.2 A minimum recording rate of 16 samples per cycle.

4.3 Trigger settings for at least the following:

4.3.1 Neutral (residual) overcurrent.

4.3.2 Phase undervoltage or overcurrent.

M4. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that FR data meets Requirement R4. Evidence may include, but is not limited to: (1) documents describing the device specification (R4, Part 4.2) and device configuration or settings (R4, Parts 4.1 and 4.3), or (2) actual data recordings or derivations.

R5. Each Reliability Coordinator shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

5.1 Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following:

5.1.1 Generating resource(s) with:

5.1.1.1 Gross individual nameplate rating greater than or equal to 500 MVA.

5.1.1.2 Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1,000 MVA.

5.1.2 Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL).

5.1.3 Each terminal of a high voltage direct current (HVDC) circuit with a nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter.

5.1.4 One or more BES Elements that are part of an Interconnection Reliability Operating Limit (IROL).

5.1.5 Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program.

5.2 Identify a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least:

5.2.1 One BES Element; and

5.2.2 One BES Element per 3,000 MW of the Reliability Coordinator's historical simultaneous peak System Demand.

5.3 Notify all owners of identified BES Elements, within 90-calendar days of completion of Part 5.1, that their respective BES Elements require DDR data when requested.

5.4 Re-evaluate all BES Elements at least once every five calendar years in accordance with Parts 5.1 and 5.2, and notify owners in accordance with Part 5.3 to implement the re-evaluated list of BES Elements as per the Implementation Plan.

M5. The Reliability Coordinator has a dated (electronic or hard copy) list of BES Elements for which DDR data is required, developed in accordance with Requirement R5, Part 5.1 and Part 5.2; and re-evaluated in accordance with Part 5.4. The Reliability Coordinator has dated evidence (electronic or hard copy) that each Transmission Owner or Generator Owner has been notified in accordance with Requirement 5, Part 5.3. Evidence may include, but is not limited to: letters, emails, electronic files, or hard copy records demonstrating transmittal of information.

R6. Each Transmission Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

6.1 One phase-to-neutral or positive sequence voltage.

6.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R6, Part 6.1, or the positive sequence current.

6.3 Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required.

6.4 Frequency of any one of the voltage(s) in Requirement R6, Part 6.1.

M6. The Transmission Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R6. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R7. Each Generator Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

7.1 One phase-to-neutral, phase-to-phase, or positive sequence voltage at either the generator step-up transformer (GSU) high-side or low-side voltage level.

7.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R7, Part 7.1, phase current(s) for any phase-to-phase voltages, or positive sequence current.

7.3 Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required.

7.4 Frequency of at least one of the voltages in Requirement R7, Part 7.1.

M7. The Generator Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R7. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R8. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have continuous data recording and storage. If the equipment was installed prior to the effective date of this standard and is not capable of continuous recording, triggered records must meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

8.1 Triggered record lengths of at least three minutes.

8.2 At least one of the following three triggers:

- Off nominal frequency trigger set at:

	Low	High
○ Eastern Interconnection	<59.75 Hz	>61.0 Hz
○ Western Interconnection	<59.55 Hz	>61.0 Hz
○ ERCOT Interconnection	<59.35 Hz	>61.0 Hz
○ Hydro-Quebec Interconnection	<58.55 Hz	>61.5 Hz

- Rate of change of frequency trigger set at:

○ Eastern Interconnection	< -0.03125 Hz/sec	> 0.125 Hz/sec
○ Western Interconnection	< -0.05625 Hz/sec	> 0.125 Hz/sec
○ ERCOT Interconnection	< -0.08125 Hz/sec	> 0.125 Hz/sec
○ Hydro-Quebec Interconnection	< -0.18125 Hz/sec	> 0.1875 Hz/sec

- Undervoltage trigger set no lower than 85 percent of normal operating voltage for a duration of 5 seconds.

M8. Each Transmission Owner and Generator Owner has dated evidence (electronic or hard copy) of data recordings and storage in accordance with Requirement R8. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings.

R9. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have DDR data that meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

9.1 Input sampling rate of at least 960 samples per second.

9.2 Output recording rate of electrical quantities of at least 30 times per second.

M9. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that DDR data meets Requirement R9. Evidence may include, but is not limited to: (1) documents describing the device specification, device configuration, or settings (R9, Part 9.1; R9, Part 9.2); or (2) actual data recordings (R9, Part 9.2).

R10. Each Transmission Owner and Generator Owner shall time synchronize all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES

Elements identified in Requirement R5 to meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

10.1 Synchronization to Coordinated Universal Time (UTC) with or without a local time offset.

10.2 Synchronized device clock accuracy within ± 2 milliseconds of UTC.

M10. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of time synchronization described in Requirement R10. Evidence may include, but is not limited to: (1) documents describing the device specification, configuration, or setting; (2) time synchronization indication or status; or 3) station drawings.

R11. Each Transmission Owner and Generator Owner shall provide, upon request, all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to the Reliability Coordinator, Regional Entity, or NERC in accordance with the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

11.1 Data will be retrievable for the period of 10-calendar days, inclusive of the day the data was recorded.

11.2 Data subject to Part 11.1 will be provided within 30-calendar days of a request unless an extension is granted by the requestor.

11.3 SER data will be provided in ASCII Comma Separated Value (CSV) format following Attachment 2.

11.4 FR and DDR data will be provided in electronic files that are formatted in conformance with C37.111, (IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later.

11.5 Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.

M11. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that data was submitted upon request in accordance with Requirement R11. Evidence may include, but is not limited to: (1) dated transmittals to the requesting entity with formatted records; (2) documents describing data storage capability, device specification, configuration or settings; or (3) actual data recordings.

R12. Each Transmission Owner and Generator Owner shall, within 90-calendar days of the discovery of a failure of the recording capability for the SER, FR or DDR data, either: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

- Restore the recording capability, or
- Submit a Corrective Action Plan (CAP) to the Regional Entity and implement it.

M12. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R12. Evidence may include, but is not limited to: (1) dated reports of discovery of a failure, (2) documentation noting the date the data recording was restored, (3) SCADA records, or (4) dated CAP transmittals to the Regional Entity and evidence that it implemented the CAP.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

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

The Transmission Owner, Generator Owner, and Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner shall retain evidence of Requirement R1, Measure M1 for five calendar years.

The Transmission Owner shall retain evidence of Requirement R6, Measure M6 for three calendar years.

The Generator Owner shall retain evidence of Requirement R7, Measure M7 for three calendar years.

The Transmission Owner and Generator Owner shall retain evidence of requested data provided as per Requirements R2, R3, R4, R8, R9, R10, R11, and R12, Measures M2, M3, M4, M8, M9, M10, M11, and M12 for three calendar years.

The Reliability Coordinator shall retain evidence of Requirement R5, Measure M5 for five calendar years.

If a Transmission Owner, Generator Owner, or Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until mitigation is completed and approved or for the time specified above, whichever is longer.

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

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Lower	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 80 percent but less than 100 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by 30-calendar days or less. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 70 percent but less than or equal to 80 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 30-calendar days and less than or equal to 60-calendar days. OR The Transmission Owner as directed by Requirement R1, Part	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 60 percent but less than or equal to 70 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 60-calendar days and less than or equal to 90-calendar days. OR The Transmission Owner as directed by Requirement R1, Part	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for less than or equal to 60 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 90-calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying one or more other owners by

			owners by 10-calendar days or less.	1.2 was late in notifying the other owners by greater than 10-calendar days but less than or equal to 20-calendar days.	1.2 was late in notifying the other owners by greater than 20-calendar days but less than or equal to 30-calendar days.	greater than 30-calendar days.
R2	Long-term Planning	Lower	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 80 percent but less than 100 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 70 percent but less than or equal to 80 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 60 percent but less than or equal to 70 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 for less than or equal to 60 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.
R3	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 80 percent but less than 100 percent of the total set of required electrical	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 70 percent but less than or equal to 80 percent of the total set of required	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 60 percent but less than or equal to 70 percent of the total set of required	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers less than or equal to 60 percent of the total set of required electrical quantities,

			quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.
R4	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data that meets more than 80 percent but less than 100 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 70 percent but less than or equal to 80 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 60 percent but less than or equal to 70 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R4.
R5	Long-term Planning	Lower	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 80 percent but less than 100 percent of the required BES Elements included in Part 5.1.	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 70 percent but less than or equal to 80 percent of the required BES Elements included in Part 5.1.	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 60 percent but less than or equal to 70 percent of the required BES Elements included in Part 5.1.	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for less than or equal to 60 percent of the required BES Elements included in Part 5.1. OR

			OR The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by 30-calendar days or less. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners by 10-calendar days or less.	OR The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 30-calendar days and less than or equal to 60 -calendar days. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners by greater than 10-calendar days but less than or equal to 20-calendar days.	OR The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 60-calendar days and less than or equal to 90-calendar days. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners by greater than 20-calendar days but less than or equal to 30-calendar days.	The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 90-calendar days. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying one or more owners by greater than 30-calendar days. OR The Reliability Coordinator failed to ensure a minimum DDR coverage per Part 5.2.
R6	Long-term Planning	Lower	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 that covered more than 80	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 70 percent	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 60 percent	The Transmission Owner failed to have DDR data as directed by Requirement R6, Parts 6.1 through 6.4.

			percent but less than 100 percent of the total required electrical quantities for all applicable BES Elements.	but less than or equal to 80 percent of the total required electrical quantities for all applicable BES Elements.	but less than or equal to 70 percent of the total required electrical quantities for all applicable BES Elements.	
R7	Long-term Planning	Lower	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 that covers more than 80 percent but less than 100 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 70 percent but less than or equal to 80 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 60 percent but less than or equal to 70 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner failed to have DDR data as directed by Requirement R7, Parts 7.1 through 7.4.
R8	Long-term Planning	Lower	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 80 percent but less than 100 percent of the BES Elements they own as	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 70 percent but less than or equal to 80 percent of the BES Elements they	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 60 percent but less than or equal to 70 percent of the BES Elements they	The Transmission Owner or Generator Owner failed to have continuous or non-continuous DDR data, as directed in Requirement R8, for the BES Elements they own as determined in Requirement R5.

			determined in Requirement R5.	own as determined in Requirement R5.	own as determined in Requirement R5.	
R9	Long-term Planning	Lower	The Transmission Owner or Generator Owner had DDR data that meets more than 80 percent but less than 100 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 70 percent but less than or equal to 80 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 60 percent but less than or equal to 70 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R9.
R10	Long-term Planning	Lower	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 90 percent but less than 100 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 80 percent but less than or equal to 90 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 70 percent but less than or equal to 80 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as	The Transmission Owner or Generator Owner failed to have time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for less than or equal to 70 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.

				directed by Requirement R10.	directed by Requirement R10.	
R11	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 30-calendar days but less than 40-calendar days after the request unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 40-calendar days but less than or equal to 50-calendar days after the request unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 50-calendar days but less than or equal to 60-calendar days after the request unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 failed to provide the requested data more than 60-calendar days after the request unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11

			Owner as directed by Requirement R11 provided more than 90 percent but less than 100 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 90 percent of the data but less than 100 percent of the data in the proper data format.	Owner as directed by Requirement R11 provided more than 80 percent but less than or equal to 90 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 80 percent of the data but less than or equal to 90 percent of the data in the proper data format.	Owner as directed by Requirement R11 provided more than 70 percent but less than or equal to 80 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 70 percent of the data but less than or equal to 80 percent of the data in the proper data format.	failed to provide less than or equal to 70 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided less than or equal to 70 percent of the data in the proper data format.
R12	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 90-calendar days but less than or equal	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 100-calendar days but less than or	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 110-calendar days but less than or	The Transmission Owner or Generator Owner as directed by Requirement R12 failed to report a failure and provide a Corrective Action Plan to the Regional Entity more than 120-calendar days after

			to 100-calendar days after discovery of the failure.	equal to 110-calendar days after discovery of the failure.	equal to 120-calendar days after discovery of the failure. OR The Transmission Owner or Generator Owner as directed by Requirement R12 submitted a CAP to the Regional Entity but failed to implement it.	discovery of the failure. OR Transmission Owner or Generator Owner as directed by Requirement R12 failed to restore the recording capability and failed to submit a CAP to the Regional Entity.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

G. References

IEEE C37.111: Common format for transient data exchange (COMTRADE) for power Systems.

IEEE C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME). Standard published 11/09/2011 by IEEE.

NPCC SP6 Report Synchronized Event Data Reporting, revised March 31, 2005

U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations (2004).

U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout in the United States and Canada (Nov. 2003)

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
1	August 2, 2006	Adopted by NERC Board of Trustees	Revised
2	November 13, 2014	Adopted by NERC Board of Trustees	Revised under Project 2007-11 and merged with PRC-018-1.
2	September 24, 2015	FERC approved PRC-005-4. Docket No. RM15-4-000; Order No. 814	

Attachment 1

Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data

(Requirement R1)

To identify monitored BES buses for sequence of events recording (SER) and Fault recording (FR) data required by Requirement 1, each Transmission Owner shall follow sequentially, unless otherwise noted, the steps listed below:

Step 1. Determine a complete list of BES buses that it owns.

For the purposes of this standard, a single BES bus includes physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid. These buses may be modeled or represented by a single node in fault studies. For example, ring bus or breaker-and-a-half bus configurations are considered to be a single bus.

Step 2. Reduce the list to those BES buses that have a maximum available calculated three phase short circuit MVA of 1,500 MVA or greater. If there are no buses on the resulting list, proceed to Step 7.

Step 3. Determine the 11 BES buses on the list with the highest maximum available calculated three phase short circuit MVA level. If the list has 11 or fewer buses, proceed to Step 7.

Step 4. Calculate the median MVA level of the 11 BES buses determined in Step 3.

Step 5. Multiply the median MVA level determined in Step 4 by 20 percent.

Step 6. Reduce the BES buses on the list to only those that have a maximum available calculated three phase short circuit MVA higher than the greater of:

- 1,500 MVA or
- 20 percent of median MVA level determined in Step 5.

Step 7. <u>If there are no BES buses on the list:</u> the procedure is complete and no FR and SER data will be required. Proceed to Step 9.

<u>If the list has 1 or more but less than or equal to 11 BES buses:</u> FR and SER data is required at the BES bus with the highest maximum available calculated three phase short circuit MVA as determined in Step 3. Proceed to Step 9.

If the list has more than 11 BES buses: SER and FR data is required on at least the 10 percent of the BES buses determined in Step 6 with the highest maximum available calculated three phase short circuit MVA. Proceed to Step 8.

Step 8. SER and FR data is required at additional BES buses on the list determined in Step 6. The aggregate of the number of BES buses determined in Step 7 and this Step will be at least 20 percent of the BES buses determined in Step 6.

The additional BES buses are selected, at the Transmission Owner's discretion, to provide maximum wide-area coverage for SER and FR data. The following BES bus locations are recommended:

- Electrically distant buses or electrically distant from other DME devices.
- Voltage sensitive areas.
- Cohesive load and generation zones.
- BES buses with a relatively high number of incident Transmission circuits.
- BES buses with reactive power devices.
- Major Facilities interconnecting outside the Transmission Owner's area.

Step 9. The list of monitored BES buses for SER and FR data for Requirement R1 is the aggregate of the BES buses determined in Steps 7 and 8.

Attachment 2

Sequence of Events Recording (SER) Data Format

(Requirement R11, Part 11.3)

Date, Time, Local Time Code, Substation, Device, State[1]

08/27/13, 23:58:57.110, -5, Sub 1, Breaker 1, Close

08/27/13, 23:58:57.082, -5, Sub 2, Breaker 2, Close

08/27/13, 23:58:47.217, -5, Sub 1, Breaker 1, Open

08/27/13, 23:58:47.214, -5, Sub 2, Breaker 2, Open

High Level Requirement Overview

[1] "OPEN" and "CLOSE" are used as examples. Other terminology such as TRIP, TRIP TO LOCKOUT, RECLOSE, etc. is also acceptable.

Requirement	Entity	Identify BES Buses	Notification	SER	FR	5 Year Re-evaluation
R1	TO	X	X	X	X	X
R2	TO | GO			X		
R3	TO | GO				X	
R4	TO | GO				X	

Requirement	Entity	Identify BES Elements	Notification	DDR	5 Year Re-evaluation
R5	RC	X	X	X	X
R6	TO			X	
R7	GO			X	
R8	TO | GO			X	
R9	TO | GO			X	

Requirement	Entity	Time Synchronization	Provide SER, FR, DDR Data	SER, FR, DDR Availability
R10	TO | GO	X		
R11	TO | GO		X	
R12	TO | GO			X

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 Functional Entities:

Because the Reliability Coordinator has the best wide-area view of the BES, the Reliability Coordinator is most suited to be responsible for determining the BES Elements for which dynamic Disturbance recording (DDR) data is required. The Transmission Owners and Generator Owners will have the responsibility for ensuring that adequate data is available for those BES Elements selected.

BES buses where sequence of events recording (SER) and fault recording (FR) data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their Systems to determine those buses. The Transmission Owners and Generator Owners that own BES Elements on those BES buses will have the responsibility for ensuring that adequate data is available.

Rationale for R1:

Analysis and reconstruction of BES events requires SER and FR data from key BES buses. Attachment 1 provides a uniform methodology to identify those BES buses. Repeated testing of the Attachment 1 methodology has demonstrated the proper distribution of SER and FR data collection. Review of actual BES short circuit data received from the industry in response to the DMSDT's data request (June 5, 2013 through July 5, 2013) illuminated a strong correlation between the available short circuit MVA at a Transmission bus and its relative size and importance to the BES based on (i) its voltage level, (ii) the number of Transmission Lines and other BES Elements connected to the BES bus, and (iii) the number and size of generating units connected to the bus. BES buses with a large short circuit MVA level are BES Elements that have a significant effect on System reliability and performance. Conversely, BES buses with very low short circuit MVA levels seldom cause wide-area or cascading System events, so SER and FR data from those BES Elements are not as significant. After analyzing and reviewing the collected data submittals from across the continent, the threshold MVA values were chosen to provide sufficient data for event analysis using engineering and operational judgment.

Concerns have existed that the defined methodology for bus selection will overly concentrate data to selected BES buses. For the purpose of PRC-002-2, there are a minimum number of BES buses for which SER and FR data is required based on the short circuit level. With these concepts and the objective being sufficient recording coverage for event analysis, the DMSDT developed the procedure in Attachment 1 that utilizes the maximum available calculated three phase short circuit MVA. This methodology ensures comparable and sufficient coverage for SER and FR data regardless of variations in the size and System topology of Transmission Owners across all Interconnections. Additionally, this methodology provides a degree of flexibility for the use of judgment in the selection process to ensure sufficient distribution.

BES buses where SER and FR data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their Systems to determine those buses.

Each Transmission Owner must re-evaluate the list of BES buses at least every five calendar years to address System changes since the previous evaluation. Changes to the BES do not mandate immediate inclusion of BES buses into the currently enforced list, but the list of BES buses will be re-evaluated at least every five calendar years to address System changes since the previous evaluation.

Since there may be multiple owners of equipment that comprise a BES bus, the notification required in R1 is necessary to ensure all owners are notified.

A 90-calendar day notification deadline provides adequate time for the Transmission Owner to make the appropriate determination and notification.

Rationale for R2:
The intent is to capture SER data for the status (open/close) of the circuit breakers that can interrupt the current flow through each BES Element connected to a BES bus. Change of state of circuit breaker position, time stamped according to Requirement R10 to a time synchronized clock, provides the basis for assembling the detailed sequence of events timeline of a power System Disturbance. Other status monitoring nomenclature can be used for devices other than circuit breakers.

Rationale for R3:
The required electrical quantities may either be directly measured or determinable if sufficient FR data is captured (e.g. residual or neutral current if the phase currents are directly measured). In order to cover all possible fault types, all BES bus phase-to-neutral voltages are required to be determinable for each BES bus identified in Requirement R1. BES bus voltage data is adequate for System Disturbance analysis. Phase current and residual current are required to distinguish between phase faults and ground faults. It also facilitates determination of the fault location and cause of relay operation. For transformers (Part 3.2.1), the data may be from either the high-side or the low-side of the transformer. Generator step-up transformers (GSUs) and leads 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 excluded from Requirement R3 because the fault current contribution from a generator to a fault on the Transmission System will be captured by FR data on the Transmission System, and Transmission System FR will capture faults on the generator interconnection.

Generator Owners may install this capability or, where the Transmission Owners already have suitable FR data, contract with the Transmission Owner. However, when required, the Generator Owner is still responsible for the provision of this data.

Rationale for R4:
Time stamped pre- and post-trigger fault data aid in the analysis of power System operations and determination if operations were as intended. System faults generally persist for a short time period, thus a 30-cycle total minimum record length is adequate. Multiple records allow for legacy microprocessor relays which, when time-synchronized, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30-contiguous cycles total.

A minimum recording rate of 16 samples per cycle (960 Hz) is required to get sufficient point on wave data for recreating accurate fault conditions.

Rationale for R5:
DDR is used for capturing the BES transient and post-transient response following Disturbances, and the data is used for event analysis and validating System performance. DDR plays a critical role in wide-area Disturbance analysis, and Requirement R5 ensures there is adequate wide-area coverage of DDR data for specific BES Elements to facilitate accurate and efficient event analysis. The Reliability Coordinator has the best wide-area view of the System and needs to ensure that there are sufficient BES Elements identified for DDR data capture. The identification of BES Elements requiring DDR data as per Requirement R5 is based upon industry experience with wide-area Disturbance analysis and the need for adequate data to facilitate event analysis. Ensuring data is captured for these BES Elements will significantly improve the accuracy of analysis and understanding of why an event occurred, not simply what occurred.

From its experience with changes to the Bulk Electric System that would affect DDR, the DMSDT decided that the five calendar year re-evaluation of the list is a reasonable interval for this review. Changes to the BES do not mandate immediate inclusion of BES Elements into the in force list, but the list of BES Elements will be re-evaluated at least every five calendar years to address System changes since the previous evaluation. However, this standard does not preclude the Reliability Coordinator from performing this re-evaluation more frequently to capture updated BES Elements.

The Reliability Coordinator must notify all owners of the selected BES Elements that DDR data is required for this standard. The Reliability Coordinator is only required to share the list of selected BES Elements that each Transmission Owner and Generator Owner respectively owns, not the entire list. This communication of selected BES Elements is required to ensure that the owners of the respective BES Elements are aware of their responsibilities under this standard.

Implementation of the monitoring equipment is the responsibility of the respective Transmission Owners and Generator Owners, the timeline for installing this capability is outlined in the Implementation Plan, and starts from notification of the list from the Reliability Coordinator. Data for each BES Element as defined by the Reliability Coordinator must be provided; however, this data can be either directly measured or accurately calculated. With the exception of HVDC circuits, DDR data is only required for one end or terminal of the BES Elements selected. For example, DDR data must be provided for at least one terminal of a

Transmission Line or generator step-up (GSU) transformer, but not both terminals. For an interconnection between two Reliability Coordinators, each Reliability Coordinator will consider this interconnection independently, and are expected to work cooperatively to determine how to monitor the BES Elements that require DDR data. For an interconnection between two TO's, or a TO and a GO, the Reliability Coordinator will determine which entity will provide the data. The Reliability Coordinator will notify the owners that their BES Elements require DDR data.

Refer to the Guidelines and Technical Basis Section for more detail on the rationale and technical reasoning for each identified BES Element in Requirement R5, Part 5.1; monitoring these BES Elements with DDR will facilitate thorough and informative event analysis of wide-area Disturbances on the BES. Part 5.2 is included to ensure wide-area coverage across all Reliability Coordinators. It is intended that each Reliability Coordinator will have DDR data for one BES Element and at least one additional BES Element per 3,000 MW of its historical simultaneous peak System Demand.

Rationale for R6:
DDR is used to measure transient response to System Disturbances during a relatively balanced post-fault condition. Therefore, it is sufficient to provide a phase-to-neutral voltage or positive sequence voltage. The electrical quantities can be determined (calculated, derived, etc.).

Because all of the BES buses within a location are at the same frequency, one frequency measurement is adequate.

The data requirements for PRC-002-2 are based on a System configuration assuming all normally closed circuit breakers on a BES bus are closed.

Rationale for R7:
A crucial part of wide-area Disturbance analysis is understanding the dynamic response of generating resources. Therefore, it is necessary for Generator Owners to have DDR at either the high- or low-side of the generator step-up transformer (GSU) measuring the specified electrical quantities to adequately capture generator response. This standard defines the 'what' of DDR, not the 'how'. Generator Owners may install this capability or, where the Transmission Owners already have suitable DDR data, contract with the Transmission Owner. However, the Generator Owner is still responsible for the provision of this data.

Rationale for R8:
Large scale System outages generally are an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Data available pre- and post-contingency helps identify the causes and effects of each event leading to outages. Therefore, continuous recording and storage are necessary to ensure sufficient data is available for the entire event.
Existing DDR data recording across the BES may not record continuously. To accommodate its use for the purposes of this standard, triggered records are acceptable if the equipment was installed prior to the effective date of this standard. The frequency triggers are defined based on the dynamic response associated with each Interconnection. The undervoltage trigger is

defined to capture possible delayed undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR).

Rationale for R9:
An input sampling rate of at least 960 samples per second, which corresponds to 16 samples per cycle on the input side of the DDR equipment, ensures adequate accuracy for calculation of recorded measurements such as complex voltage and frequency.
An output recording rate of electrical quantities of at least 30 times per second refers to the recording and measurement calculation rate of the device. Recorded measurements of at least 30 times per second provide adequate recording speed to monitor the low frequency oscillations typically of interest during power System Disturbances.

Rationale for R10:
Time synchronization of Disturbance monitoring data is essential for time alignment of large volumes of geographically dispersed records from diverse recording sources. Coordinated Universal Time (UTC) is a recognized time standard that utilizes atomic clocks for generating precision time measurements. All data must be provided in UTC formatted time either with or without the local time offset, expressed as a negative number (the difference between UTC and the local time zone where the measurements are recorded).
Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment. The equipment used to measure the electrical quantities must be time synchronized to ± 2 ms accuracy; however, accuracy of the application of this time stamp and therefore the accuracy of the data itself is not mandated. This is because of inherent delays associated with measuring the electrical quantities and events such as breaker closing, measurement transport delays, algorithm and measurement calculation techniques, etc. Ensuring that the monitoring devices internal clocks are within ± 2 ms accuracy will suffice with respect to providing time synchronized data.

Rationale for R11:
Wide-area Disturbance analysis includes data recording from many devices and entities. Standardized formatting and naming conventions of these files significantly improves timely analysis.

Providing the data within 30-calendar days (or the granted extension time), subject to Part 11.1, allows for reasonable time to collect the data and perform any necessary computations or formatting.

Data is required to be retrievable for 10-calendar days inclusive of the day the data was recorded, i.e. a 10-calendar day rolling window of available data. Data hold requests are usually initiated the same or next day following a major event for which data is requested. A 10-calendar day time frame provides a practical limit on the duration of data required to be stored and informs the requesting entities as to how long the data will be available. The requestor of data has to be aware of the Part 11.1 10-calendar day retrievability because requiring data retention for a longer period of time is expensive and unnecessary.

SER data shall be provided in a simple ASCII .CSV format as outlined in Attachment 2. Either equipment can provide the data or a simple conversion program can be used to convert files into this format. This will significantly improve the data format for event records, enabling the use of software tools for analyzing the SER data.

Part 11.4 specifies FR and DDR data files be provided in conformance with IEEE C37.111, IEEE Standard for Common Format for Transient Exchange (COMTRADE), revision 1999 or later. The use of IEEE C37.111-1999 or later is well established in the industry. C37.111-2013 is a version of COMTRADE that includes an annex describing the application of the COMTRADE standard to synchrophasor data; however, version C37.111-1999 is commonly used in the industry today.

Part 11.5 uses a standardized naming format, C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), for providing Disturbance monitoring data. This file format allows a streamlined analysis of large Disturbances, and includes critical records such as local time offset associated with the synchronization of the data.

Rationale for R12:

Each Transmission Owner and Generator Owner who owns equipment used for collecting the data required for this standard must repair any failures within 90-calendar days to ensure that adequate data is available for event analysis. If the Disturbance monitoring capability cannot be restored within 90-calendar days (e.g. budget cycle, service crews, vendors, needed outages, etc.), the entity must develop a Corrective Action Plan (CAP) for restoring the data recording capability. The timeline required for the CAP depends on the entity and the type of data required. It is treated as a failure if the recording capability is out of service for maintenance and/or testing for greater than 90-calendar days. An outage of the monitored BES Element does not constitute a failure of the Disturbance monitoring capability.

Guidelines and Technical Basis Section

Introduction

The emphasis of PRC-002-2 is not on how Disturbance monitoring data is captured, but what Bulk Electric System data is captured. There are a variety of ways to capture the data PRC-002-2 addresses, and existing and currently available equipment can meet the requirements of this standard. PRC-002-2 also addresses the importance of addressing the availability of Disturbance monitoring capability to ensure the completeness of BES data capture.

The data requirements for PRC-002-2 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

PRC-002-2 addresses “what” data is recorded, not “how” it is recorded.

Guideline for Requirement R1:

Sequence of events and fault recording for the analysis, reconstruction, and reporting of System Disturbances is important. However, SER and FR data is not required at every BES bus on the BES to conduct adequate or thorough analysis of a Disturbance. As major tools of event analysis, the time synchronized time stamp for a breaker change of state and the recorded waveforms of voltage and current for individual circuits allows the precise reconstruction of events of both localized and wide-area Disturbances.

More quality information is always better than less when performing event analysis. However, 100 percent coverage of all BES Elements is not practical nor required for effective analysis of wide-area Disturbances. Therefore, selectivity of required BES buses to monitor is important for the following reasons:

1. Identify key BES buses with breakers where crucial information is available when required.
2. Avoid excessive overlap of coverage.
3. Avoid gaps in critical coverage.
4. Provide coverage of BES Elements that could propagate a Disturbance.
5. Avoid mandates to cover BES Elements that are more likely to be a casualty of a Disturbance rather than a cause.
6. Establish selection criteria to provide effective coverage in different regions of the continent.

The major characteristics available to determine the selection process are:

1. System voltage level;
2. The number of Transmission Lines into a substation or switchyard;
3. The number and size of connected generating units;
4. The available short circuit levels.

Although it is straightforward to establish criteria for the application of identified BES buses, analysis was required to establish a sound technical basis to fulfill the required objectives.

To answer these questions and establish criteria for BES buses of SER and FR, the DMSDT established a sub-team referred to as the Monitored Value Analysis Team (MVA Team). The MVA Team collected information from a wide variety of Transmission Systems throughout the continent to analyze Transmission buses by the characteristics previously identified for the selection process.

The MVA Team learned that the development of criteria is not possible for adequate SER and FR coverage, based solely upon simple, bright line characteristics, such as the number of lines into a substation or switchyard at a particular voltage level or at a set level of short circuit current. To provide the appropriate coverage, a relatively simple but effective Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data was developed. This Procedure, included as Attachment 1, assists entities in fulfilling Requirement R1 of the standard.

The Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data is weighted to buses with higher short circuit levels. This is chosen for the following reasons:

1. The method is voltage level independent.
2. It is likely to select buses near large generation centers.
3. It is likely to select buses where delayed clearing can cause Cascading.
4. Selected buses directly correlate to the Universal Power Transfer equation: Lower Impedance – increased power flows – greater System impact.

To perform the calculations of Attachment 1, the following information below is required and the following steps (provided in summary form) are required for Systems with more than 11 BES buses with three phase short circuit levels above 1,500 MVA.

1. Total number of BES buses in the Transmission System under evaluation.
   a. Only tangible substation or switchyard buses are included.
   b. Pseudo buses created for analysis purposes in System models are excluded.
2. Determine the three phase short circuit MVA for each BES bus.
3. Exclude BES buses from the list with short circuit levels below 1,500 MVA.
4. Determine the median short circuit for the top 11 BES buses on the list (position number 6).
5. Multiply median short circuit level by 20 percent.
6. Reduce the list of BES buses to those with short circuit levels higher than 20 percent of the median.
7. Apply SER and FR at BES buses with short circuit levels in the top 10 percent of the list (from 6).

8. Apply SER and FR at BES buses at an additional 10 percent of the list using engineering judgment, and allowing flexibility to factor in the following considerations:
   - Electrically distant BES buses or electrically distant from other DME devices
   - Voltage sensitive areas
   - Cohesive load and generation zones
   - BES buses with a relatively high number of incident Transmission circuits
   - BES buses with reactive power devices
   - Major facilities interconnecting outside the Transmission Owner's area.

For event analysis purposes, more valuable information is attained about generators and their response to System events pre- and post-contingency through DDR data versus SER or FR records. SER data of the opening of the primary generator output interrupting devices (e.g. synchronizing breaker) may not reliably indicate the actual time that a generator tripped; for instance, when it trips on reverse power after loss of its prime mover (e.g. combustion or steam turbine). As a result, this standard only requires DDR data.

The re-evaluation interval of five years was chosen based on the experience of the DMSDT to address changing System configurations while creating balance in the frequency of re-evaluations.

Guideline for Requirement R2:

Analyses of wide-area Disturbances often begin by evaluation of SERs to help determine the initiating event(s) and follow the Disturbance propagation. Recording of breaker operations help determine the interruption of line flows while generator loading is best determined by DDR data, since generator loading can be essentially zero regardless of breaker position. However, generator breakers directly connected to an identified BES bus are required to have SER data captured. It is important in event analysis to know when a BES bus is cleared regardless of a generator's loading.

Generator Owners are included in this requirement because a Generator Owner may, in some instances, own breakers directly connected to the Transmission Owner's BES bus.

Guideline for Requirement R3:

The BES buses for which FR data is required are determined based on the methodology described in Attachment 1 of the standard. The BES Elements connected to those BES buses for which FR data is required include:

- Transformers with a low-side operating voltage of 100kV or above
- Transmission Lines

Only those BES Elements that are identified as BES as defined in the latest in effect NERC definition are to be monitored. For example, radial lines or transformers with low-side voltage less than 100kV are not included.

FR data must be determinable from each terminal of a BES Element connected to applicable BES buses.

Generator step-up transformers (GSU) are excluded from the above based on the following:

- Current contribution from a generator in case of fault on the Transmission System will be captured by FR data on the Transmission System.
- For faults on the interconnection to generating facilities it is sufficient to have fault current data from the Transmission station end of the interconnection. Current contribution from a generator can be readily calculated if needed.

The DMSDT, after consulting with NERC's Event Analysis group, determined that DDR data from selected generator locations was more important for event analysis than FR data.

Recording of Electrical Quantities

For effective fault analysis it is necessary to know values of all phase and neutral currents and all phase-to-neutral voltages. Based on such FR data it is possible to determine all fault types. FR data also augments SERs in evaluating circuit breaker operation.

Current Recordings

The required electrical quantities are normally directly measured. Certain quantities can be derived if sufficient data is measured, for example residual or neutral currents.
Since a Transmission System is generally well balanced, with phase currents having essentially similar magnitudes and phase angle differences of 120°, during normal conditions there is negligible neutral (residual) current. In case of a ground fault the resulting phase current imbalance produces residual current that can be either measured or calculated.

Neutral current, also known as ground or residual current $\mathbf{I}_r$, is calculated as a sum of vectors of three phase currents:

$\mathbf{I}_r = 3 \bullet \mathbf{I}_0 = \mathbf{I}_A + \mathbf{I}_B + \mathbf{I}_C$

$\mathbf{I}_0$ - Zero-sequence current

$\mathbf{I}_A$, $\mathbf{I}_B$, $\mathbf{I}_C$ - Phase current (vectors)

Another example of how required electrical quantities can be derived is based on Kirchhoff's Law. Fault currents for one of the BES Elements connected to a particular BES bus can be derived as a vectorial sum of fault currents recorded at the other BES Elements connected to that BES bus.

Voltage Recordings

Voltages are to be recorded or accurately determined at applicable BES buses.

Guideline for Requirement R4:

Pre- and post-trigger fault data along with the SER breaker data, all time stamped to a common clock at millisecond accuracy, aid in the analysis of protection System operations after a fault to determine if a protection System operated as designed. Generally speaking, BES faults persist for a very short time period, approximately 1 to 30 cycles, thus a 30-cycle record length provides adequate data. Multiple records allow for legacy microprocessor relays which, when time synchronized to a common clock, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30-contiguous cycles total.

A minimum recording rate of 16 samples per cycle is required to get accurate waveforms and to get 1 millisecond resolution for any digital input which may be used for FR.

FR triggers can be set so that when the monitored value on the recording device goes above or below the trigger value, data is recorded. Requirement R4, sub-Part 4.3.1 specifies a neutral (residual) overcurrent trigger for ground faults. Requirement R4, sub-Part 4.3.2 specifies a phase undervoltage or overcurrent trigger for phase-to-phase faults.

Guideline for Requirement R5:

DDR data is used for wide-area Disturbance monitoring to determine the System's electromechanical transient and post-transient response and validate System model performance. DDR is typically located based on strategic studies which include angular, frequency, voltage, and oscillation stability. However, for adequately monitoring the System's dynamic response and ensuring sufficient coverage to determine System performance, DDR is required for key BES Elements in addition to a minimum requirement of DDR coverage.

Each Reliability Coordinator is required to identify sufficient DDR data capture for, at a minimum, one BES Element and then one additional BES Element per 3,000 MW of historical simultaneous peak System Demand. This DDR data is included to provide adequate System wide coverage across an Interconnection. To clarify, if any of the key BES Elements requiring DDR monitoring are within the Reliability Coordinator Area, DDR data capability is required. If a Reliability Coordinator does not meet the requirements of Part 5.1, additional coverage had to be specified.

Loss of large generating resources poses a frequency and angular stability risk for all Interconnections across North America. Data capturing the dynamic response of these machines during a Disturbance helps the analysis of large Disturbances. Having data regarding generator dynamic response to Disturbances greatly improves understanding of ***why*** an event occurs rather than what occurred. To determine and provide the basis for unit size criteria, the DMSDT acquired specific generating unit data from NERC's Generating Availability Data System (GADS) program. The data contained generating unit size information for each generating unit in North America which was reported in 2013 to the NERC GADS program. The DMSDT analyzed the spreadsheet data to determine: (i) how many units were above or below selected size

thresholds; and (ii) the aggregate sum of the ratings of the units within the boundaries of those thresholds. Statistical information about this data was then produced, i.e. averages, means and percentages. The DMSDT determined the following basic information about the generating units of interest (current North America fleet, i.e. units reporting in 2013) included in the spreadsheet:

- The number of individual generating units in total included in the spreadsheet.
- The number of individual generating units rated at 20 MW or larger included in the spreadsheet. These units would generally require that their owners be registered as GOs in the NERC CMEP.
- The total number of units within selected size boundaries.
- The aggregate sum of ratings, in MWs, of the units within the boundaries of those thresholds.

The information in the spreadsheet does not provide information by which the plant information location of each unit can be determined, i.e. the DMSDT could not use the information to determine which units were located together at a given generation site or facility.

From this information, the DMSDT was able to reasonably speculate the generating unit size thresholds proposed in Requirement R5, sub-Part 5.1.1 of the standard. Generating resources intended for DDR data recording are those individual units with gross nameplate ratings "greater than or equal to 500 MVA". The 500 MVA individual unit size threshold was selected because this number roughly accounts for 47 percent of the generating capacity in NERC footprint while only requiring DDR coverage on about 12.5 percent of the generating units. As mentioned, there was no data pertaining to unit location for aggregating plant/facility sizes. However, Requirement R5, sub-Part 5.1.1 is included to capture larger units located at large generating plants which could pose a stability risk to the System if multiple large units were lost due to electrical or non-electrical contingencies. For generating plants, each individual generator at the plant/facility with a gross nameplate rating greater than or equal to 300 MVA must have DDR where the gross nameplate rating of the plant/facility is greater than or equal to 1,000 MVA. The 300 MVA threshold was chosen based on the DMSDT's judgment and experience. The incremental impact to the number of units requiring monitoring is expected to be relatively low. For combined cycle plants where only one generator has a rating greater than or equal to 300MVA, that is the only generator that would need DDR.

Permanent System Operating Limits (SOLs) are used to operate the System within reliable and secure limits. In particular, SOLs related to angular or voltage stability have a significant impact on BES reliability and performance. Therefore, at least one BES Element of an SOL should be monitored.

The draft standard requires "One or more BES Elements that are part of an Interconnection Reliability Operating Limits (IROLs)." Interconnection Reliability Operating Limits (IROLs) are included because the risk of violating these limits poses a risk to System stability and the potential for cascading outages. IROLs may be defined by a single or multiple monitored BES

Element(s) and contingent BES Element(s). The standard does not dictate selection of the contingent and/or monitored BES Elements. Rather the Drafting Team believes this determination is best made by the Reliability Coordinator for each IROL considered based on the severity of violating this IROL.

Locations where an undervoltage load shedding (UVLS) program is deployed are prone to voltage instability since they are generally areas of significant Demand. The Reliability Coordinator will identify these areas where a UVLS is in service and identify a useful and effective BES Element to monitor for DDR such that action of the UVLS or voltage instability on the BES could be captured. For example, a major 500kV or 230kV substation on the EHV System close to the load pocket where the UVLS is deployed would likely be a valuable electrical location for DDR coverage and would aid in post-Disturbance analysis of the load area's response to large System excursions (voltage, frequency, etc.).

Guideline for Requirement R6:

DDR data shows transient response to System Disturbances after a fault is cleared (post-fault), under a relatively balanced operating condition. Therefore, it is sufficient to provide a single phase-to-neutral voltage or positive sequence voltage. Recording of all three phases of a circuit is not required, although this may be used to compute and record the positive sequence voltage.

The bus where a voltage measurement is required is based on the list of BES Elements defined by the Reliability Coordinator in Requirement R5. The intent of the standard is not to require a separate voltage measurement of each BES Element where a common bus voltage measurement is available. For example, a breaker-and-a-half or double-bus configuration with a North (or East) Bus and South (or West) Bus, would require both buses to have voltage recording because either can be taken out of service indefinitely with the targeted BES Element remaining in service. This may be accomplished either by recording both bus voltages separately, or by providing a selector switch to connect either of the bus voltage sources to a single recording input of the DDR device. This component of the requirement is therefore included to mitigate the potential of failed frequency, phase angle, real power, and reactive power calculations due to voltage measurements removed from service while sufficient voltage measurement is actually available during these operating conditions.

It must be emphasized that the data requirements for PRC-002-2 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

When current recording is required, it should be on the same phase as the voltage recording taken at the location if a single phase-to-neutral voltage is provided. Positive sequence current recording is also acceptable.

For all circuits where current recording is required, Real and Reactive Power will be recorded on a three phase basis. These recordings may be derived either from phase quantities or from positive sequence quantities.

Guideline for Requirement R7:

All Guidelines specified for Requirement R6 apply to Requirement R7. Since either the high- or low-side windings of the generator step-up transformer (GSU) may be connected in delta, phase-to-phase voltage recording is an acceptable voltage recording. As was explained in the Guideline for Requirement R6, the BES is operating under a relatively balanced operating condition and, if needed, phase-to-neutral quantities can be derived from phase-to-phase quantities.

Again it must be emphasized that the data requirements for PRC-002-2 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

Guideline for Requirement R8:

Wide-area System outages are generally an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Pre- and post-contingency data helps identify the causes and effects of each event leading to the outages. This drives a need for continuous recording and storage to ensure sufficient data is available for the entire Disturbance.

Transmission Owners and Generator Owners are required to have continuous DDR for the BES Elements identified in Requirement R6. However, this requirement recognizes that legacy equipment may exist for some BES Elements that do not have continuous data recording capabilities. For equipment that was installed prior to the effective date of the standard, triggered DDR records of three minutes are acceptable using at least one of the trigger types specified in Requirement R8, Part 8.2:

- Off nominal frequency triggers are used to capture high- or low-frequency excursions of significant size based on the Interconnection size and inertia.
- Rate of change of frequency triggers are used to capture major changes in System frequency which could be caused by large changes in generation or load, or possibly changes in System impedance.
- The undervoltage trigger specified in this standard is provided to capture possible sustained undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR) events. A sustained voltage of 85 percent is outside normal schedule operating voltages and is sufficiently low to capture abnormal voltage conditions on the BES.

Guideline for Requirement R9:

DDR data contains the dynamic response of a power System to a Disturbance and is used for analyzing complex power System events. This recording is typically used to capture short-term

and long-term Disturbances, such as a power swing. Since the data of interest is changing over time, DDR data is normally stored in the form of RMS values or phasor values, as opposed to directly sampled data as found in FR data.

The issue of the sampling rate used in a recording instrument is quite important for at least two reasons: the anti-aliasing filter selection and accuracy of signal representation. The anti-aliasing filter selection is associated with the requirement of a sampling rate at least twice the highest frequency of a sampled signal. At the same time, the accuracy of signal representation is also dependent on the selection of the sampling rate. In general, the higher the sampling rate, the better the representation. In the abnormal conditions of interest (e.g. faults or other Disturbances); the input signal may contain frequencies in the range of 0-400 Hz. Hence, the rate of 960 samples per second (16 samples/cycle) is considered an adequate sampling rate that satisfies the input signal requirements.

In general, dynamic events of interest are: inter-area oscillations, local generator oscillations, wind turbine generator torsional modes, HVDC control modes, exciter control modes, and steam turbine torsional modes. Their frequencies range from 0.1-20 Hz. In order to reconstruct these dynamic events, a minimum recording time of 30 times per second is required.

Guideline for Requirement R10: Time synchronization of Disturbance monitoring data allows for the time alignment of large volumes of geographically dispersed data records from diverse recording sources. A universally recognized time standard is necessary to provide the foundation for this alignment. Coordinated Universal Time (UTC) is the foundation used for the time alignment of records. It is an international time standard utilizing atomic clocks for generating precision time measurements at fractions of a second levels. The local time offset, expressed as a negative number, is the difference between UTC and the local time zone where the measurements are recorded.

Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment.

Time synchronization accuracy is specified in response to Recommendation 12b in the NERC August, 2003, Blackout Final NERC Report Section V Conclusions and Recommendations:

“Recommendation 12b: Facilities owners shall, in accordance with regional criteria, upgrade existing dynamic recorders to include GPS time synchronization…”

Also, from the U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout, November 2003, in the United States and Canada, page 103:

“Establishing a precise and accurate sequence of outage-related events was a critical building block for the other parts of the investigation. One of the key problems in developing this sequence was that although much of the data pertinent to an event was time-stamped, there was some variance from source to source in how the time-stamping was done, and not all of the time-stamps were synchronized…”

From NPCC's SP6 Report Synchronized Event Data Reporting, revised March 31, 2005, the investigation by the authoring working group revealed that existing GPS receivers can be expected to provide a time code output which has an uncertainty on the order of 1 millisecond, uncertainty being a quantitative descriptor.

Guideline for Requirement R11:

This requirement directs the applicable entities, upon requests from the Reliability Coordinator, Regional Entity or NERC, to provide SER and FR data for BES buses determined in Requirement R1 and DDR data for BES Elements determined as per Requirement R5. To facilitate the analysis of BES Disturbances, it is important that the data is provided to the requestor within a reasonable period of time.

Requirement R11, Part 11.1 specifies the maximum time frame of 30-calendar days to provide the data. Thirty calendar days is a reasonable time frame to allow for the collection of data, and submission to the requestor. An entity may request an extension of the 30-day submission requirement. If granted by the requestor, the entity must submit the data within the approved extended time.

Requirement R11, Part 11.2 specifies that the minimum time period of 10-calendar days inclusive of the day the data was recorded for which the data will be retrievable. With the equipment in use that has the capability of recording data, having the data retrievable for the 10-calendar days is realistic and doable. It is important to note that applicable entities should account for any expected delays in retrieving data and this may require devices to have data available for more than 10 days. To clarify the 10-calendar day time frame, an incident occurs on Day 1. If a request for data is made on Day 6, then that data has to be provided to the requestor within 30-calendar days after a request or a granted time extension. However, if a request for the data is made on Day 11, that is outside the 10-calendar days specified in the requirement, and an entity would not be out of compliance if it did not have the data.

Requirement R11, Part 11.3 specifies a Comma Separated Value (CSV) format according to Attachment 2 for the SER data. It is necessary to establish a standard format as it will be incorporated with other submitted data to provide a detailed sequence of events timeline of a power System Disturbance.

Requirement R11, Part 11.4 specifies the IEEE C37.111 COMTRADE format for the FR and DDR data. The IEEE C37.111 is the Standard for Common Format for Transient Data Exchange and is well established in the industry. It is necessary to specify a standard format as multiple submissions of data from many sources will be incorporated to provide a detailed analysis of a power System Disturbance. The latest revision of COMTRADE (C37.111-2013) includes an annex describing the application of the COMTRADE standard to synchophasor data.

Requirement R11, Part 11.5 specifies the IEEE C37.232 COMNAME format for naming the data files of the SER, FR and DDR. The IEEE C37.232 is the Standard for Common Format for Naming Time Sequence Data Files. The first version was approved in 2007. From the August 14, 2003 blackout there were thousands of Fault Recording data files collected. The collected data files

did not have a common naming convention and it was therefore difficult to discern which files came from which utilities and which ones were captured by which devices. The lack of a common naming practice seriously hindered the investigation process. Subsequently, and in its initial report on the blackout, NERC stressed the need for having a common naming practice and listed it as one of its top ten recommendations.

Guideline for Requirement R12:

This requirement directs the respective owners of Transmission and Generator equipment to be alert to the proper functioning of equipment used for SER, FR, and DDR data capabilities for the BES buses and BES Elements, which were established in Requirements R1 and R5. The owners are to restore the capability within 90-calendar days of discovery of a failure. This requirement is structured to recognize that the existence of a "reasonable" amount of capability out-of-service does not result in lack of sufficient data for coverage of the System. Furthermore, 90-calendar days is typically sufficient time for repair or maintenance to be performed. However, in recognition of the fact that there may be occasions for which it is not possible to restore the capability within 90-calendar days, the requirement further provides that, for such cases, the entity submit a Corrective Action Plan (CAP) to the Regional Entity and implement it. These actions are considered to be appropriate to provide for robust and adequate data availability.

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 initial ballot	August 2018 – September 2018
10-day final ballot	September 2018
NERC Board adoption	November 2018

A. Introduction

1. **Title:** **Transmission Relay Loadability**

2. **Number:** PRC-023-54

3. **Purpose:** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.

4. **Applicability:**

   4.1. Functional Entity:

   4.1.1 Transmission Owner with load-responsive phase protection systems as described in PRC-023-4 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

   4.1.2 Generator Owner with load-responsive phase protection systems as described in PRC-023-4 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

   4.1.3 Distribution Provider with load-responsive phase protection systems as described in PRC-023-4 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*, provided those circuits have bi-directional flow capabilities.

   4.1.4 Planning Coordinator

   4.2. Circuits:

   4.2.1 Circuits Subject to Requirements R1 – R5:

   4.2.1.1 Transmission lines operated at 200 kV and above, except 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.

   4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

   4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

   4.2.1.4 Transformers with low voltage terminals connected at 200 kV and above.

   4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

   4.2.1.6 Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

   4.2.2 Circuits Subject to Requirement R6:

   4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, except 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.

4.2.2.2 Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES, except 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.

5. Effective Dates: See Implementation Plan for the Revised Definition of "Remedial Action Scheme".

B. Requirements

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*.

Criteria:

1. Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).

2. Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating[1] of a circuit (expressed in amperes).

3. Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:

- An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.
- An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.

4. Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:

- 115% of the highest emergency rating of the series capacitor.
- 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with Requirement R1, criterion 3, using the full line inductive reactance.

[1] When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

5. Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).

6. Not used.

7. Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.

8. Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.

9. Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.

10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that the relays do not operate at or below the greater of:

- 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
- 115% of the highest operator established emergency transformer rating.

10.1 Set load-responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability[2].

11. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, criterion 10 set the relays according to one of the following:

- Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater, for at least 15 minutes to provide time for the operator to take controlled action to relieve the overload.
- Install supervision for the relays using either a top oil or simulated winding hot spot temperature element set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature[3].

12. When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:

a. Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.

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[2] As illustrated by the "dotted line" in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration*, Clause 4.4, Figure 4.

[3] IEEE standard C57.91, Tables 7 and 8, specify that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and Annex A cautions that bubble formation may occur above 140 degrees C.

b. Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.

c. Include a relay setting component of 87% of the current calculated in Requirement R1, criterion 12 in the Facility Rating determination for the circuit.

13. Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion 7, 8, 9, 12, or 13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the ERO to compile a list of all circuits that have protective relay settings that limit circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

R6. Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in PRC-023-4, Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

6.1 Maintain a list of circuits subject to PRC-023-4 per application of Attachment B, including identification of the first calendar year in which any criterion in PRC-023-4, Attachment B applies.

6.2 Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

C. Measures

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is

set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)

M2. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its out-of-step blocking elements is set to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. (R2)

M3. Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)

M4. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)

M5. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)

M6. Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within PRC-023-4, Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe. (R6)

D. 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. Data Retention

The Transmission Owner, Generator Owner, Distribution Provider and Planning Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5 for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in Requirement R6. The Planning Coordinator shall retain the most recent list of circuits in its Planning Coordinator area for which applicable entities must comply with the standard, as determined per Requirement R6.

If a Transmission Owner, Generator Owner, Distribution Provider, or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time specified above, whichever is longer.

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

1.3. Compliance Monitoring and Assessment Processes

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information

None.

2. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. OR The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.
R2	N/A	N/A	N/A	The responsible entity failed to ensure that its out-of-step blocking elements allowed tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.
R3	N/A	N/A	N/A	The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the Facility Rating of the circuit.

Requirement	Lower	Moderate	High	Severe
				OR The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.
R4	N/A	N/A	N/A	The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports.
R5	N/A	N/A	N/A	The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once each calendar year, with no more than 15 months between reports.
R6	N/A	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24	The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

Requirement	Lower	Moderate	High	Severe
		than 15 months and less than 24 months lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first applies. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after	months or more lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)	OR The Planning Coordinator used the criteria established within Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process described in Requirement R6. (part 6.1) OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met

Requirement	Lower	Moderate	High	Severe
		the list was established or updated. (part 6.2)		6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2) OR The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

E. Regional Differences

None.

F. Supplemental Technical Reference Document

1. The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies.

"Determination and Application of Practical Relaying Loadability Ratings," Version 1.0, June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: http://www.nerc.com/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Final_2008July3.pdf

Version History

Version	Date	Action	Change Tracking
1	February 12, 2008	Approved by Board of Trustees	New
1	March 19, 2008	Corrected typo in last sentence of Severe VSL for Requirement 3 — "then" should be "than."	Errata
1	March 18, 2010	Approved by FERC	
1	Filed for approval April 19, 2010	Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733	Revision
2	March 10, 2011 approved by Board of Trustees	Revised to address initial set of directives from Order 733	Revision (Project 2010-13)
2	March 15, 2012	FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)	
3	November 7, 2013	Adopted by NERC Board of Trustees	Supplemental SAR to Clarify applicability for consistency with PRC-025-1 and other minor corrections.

Version	Date	Action	Change Tracking
4	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
4	November 19, 2015	FERC Order issued approving PRC-023-4. Docket No. RM15-13-000.	

PRC-023-4 — Attachment A

1. This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:

1.1. Phase distance.

1.2. Out-of-step tripping.

1.3. Switch-on-to-fault.

1.4. Overcurrent relays.

1.5. Communications aided protection schemes including but not limited to:

1.5.1 Permissive overreach transfer trip (POTT).

1.5.2 Permissive under-reach transfer trip (PUTT).

1.5.3 Directional comparison blocking (DCB).

1.5.4 Directional comparison unblocking (DCUB).

1.6. Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.

2. The following protection systems are excluded from requirements of this standard:

2.1. Relay elements that are only enabled when other relays or associated systems fail. For example:

- Overcurrent elements that are only enabled during loss of potential conditions.
- Elements that are only enabled during a loss of communications except as noted in section 1.6.

2.2. Protection systems intended for the detection of ground fault conditions.

2.3. Protection systems intended for protection during stable power swings.

2.4. Not used.

2.5. Relay elements used only for Remedial Action Schemes applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017 or their successors.

2.6. Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.

2.7. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.

2.8. Relay elements associated with dc lines.

2.9. Relay elements associated with dc converter transformers.

PRC-023-4 — Attachment B

Circuits to Evaluate

- Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the Bulk Electric System.

Criteria

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

B1. The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.

B2. The circuit is selected by the Planning Coordinator based on Planning Assessments that identify instances of instability, Cascading, or uncontrolled separation.

~~**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.~~

B3. The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.

B4. The circuit is identified through the following sequence of power flow analyses[4] performed by the Planning Coordinator for the one-to-five-year planning horizon:

a. Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).

b. For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.

[4] Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

c. When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.

d. The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.

   i. If the Facility Rating is based on a loading duration of up to and including four hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.

   ii. If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.

   iii. If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.

e. Radially operated circuits serving only load are excluded.

B5. The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.

B6. The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard 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 initial ballot	August 2018 – September 2018
10-day final ballot	September 2018
NERC Board adoption	November 2018

A. Introduction

1. **Title:** **Transmission Relay Loadability**

2. **Number:** PRC-023-5

3. **Purpose:** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.

4. **Applicability:**

   4.1. Functional Entity:

   4.1.1 Transmission Owner with load-responsive phase protection systems as described in PRC-023-4 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

   4.1.2 Generator Owner with load-responsive phase protection systems as described in PRC-023-4 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

   4.1.3 Distribution Provider with load-responsive phase protection systems as described in PRC-023-4 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*, provided those circuits have bi-directional flow capabilities.

   4.1.4 Planning Coordinator

   4.2. Circuits:

   4.2.1 Circuits Subject to Requirements R1 – R5:

   4.2.1.1 Transmission lines operated at 200 kV and above, except 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.

   4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

   4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

   4.2.1.4 Transformers with low voltage terminals connected at 200 kV and above.

   4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

   4.2.1.6 Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

   4.2.2 Circuits Subject to Requirement R6:

   4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, except 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.

4.2.2.2 Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES, except 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.

5. Effective Dates: See Implementation Plan for the Revised Definition of "Remedial Action Scheme".

B. Requirements

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*.

Criteria:

1. Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).

2. Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating[1] of a circuit (expressed in amperes).

3. Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:

- An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.
- An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.

4. Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:

- 115% of the highest emergency rating of the series capacitor.
- 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with Requirement R1, criterion 3, using the full line inductive reactance.

[1] When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

5. Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).

6. Not used.

7. Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.

8. Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.

9. Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.

10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that the relays do not operate at or below the greater of:

- 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
- 115% of the highest operator established emergency transformer rating.

10.1 Set load-responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability[2].

11. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, criterion 10 set the relays according to one of the following:

- Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater, for at least 15 minutes to provide time for the operator to take controlled action to relieve the overload.
- Install supervision for the relays using either a top oil or simulated winding hot spot temperature element set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature[3].

12. When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:

a. Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.

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[2] As illustrated by the "dotted line" in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration*, Clause 4.4, Figure 4.

[3] IEEE standard C57.91, Tables 7 and 8, specify that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and Annex A cautions that bubble formation may occur above 140 degrees C.

b. Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.

c. Include a relay setting component of 87% of the current calculated in Requirement R1, criterion 12 in the Facility Rating determination for the circuit.

13. Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion 7, 8, 9, 12, or 13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the ERO to compile a list of all circuits that have protective relay settings that limit circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

R6. Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in PRC-023-4, Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

6.1 Maintain a list of circuits subject to PRC-023-4 per application of Attachment B, including identification of the first calendar year in which any criterion in PRC-023-4, Attachment B applies.

6.2 Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

C. Measures

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is

set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)

M2. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its out-of-step blocking elements is set to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. (R2)

M3. Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)

M4. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)

M5. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)

M6. Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within PRC-023-4, Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe. (R6)

D. 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. Data Retention

The Transmission Owner, Generator Owner, Distribution Provider and Planning Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5 for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in Requirement R6. The Planning Coordinator shall retain the most recent list of circuits in its Planning Coordinator area for which applicable entities must comply with the standard, as determined per Requirement R6.

If a Transmission Owner, Generator Owner, Distribution Provider, or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time specified above, whichever is longer.

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

1.3. Compliance Monitoring and Assessment Processes

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information

None.

2. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. OR The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.
R2	N/A	N/A	N/A	The responsible entity failed to ensure that its out-of-step blocking elements allowed tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.
R3	N/A	N/A	N/A	The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the Facility Rating of the circuit.

Requirement	Lower	Moderate	High	Severe
				OR The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.
R4	N/A	N/A	N/A	The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports.
R5	N/A	N/A	N/A	The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once each calendar year, with no more than 15 months between reports.
R6	N/A	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24	The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

Requirement	Lower	Moderate	High	Severe
		than 15 months and less than 24 months lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first applies. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after	months or more lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)	OR The Planning Coordinator used the criteria established within Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process described in Requirement R6. (part 6.1) OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met

Requirement	Lower	Moderate	High	Severe
		the list was established or updated. (part 6.2)		6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2) OR The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

E. Regional Differences

None.

F. Supplemental Technical Reference Document

1. The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies.

"Determination and Application of Practical Relaying Loadability Ratings," Version 1.0, June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: http://www.nerc.com/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Final_2008July3.pdf

Version History

Version	Date	Action	Change Tracking
1	February 12, 2008	Approved by Board of Trustees	New
1	March 19, 2008	Corrected typo in last sentence of Severe VSL for Requirement 3 — "then" should be "than."	Errata
1	March 18, 2010	Approved by FERC	
1	Filed for approval April 19, 2010	Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733	Revision
2	March 10, 2011 approved by Board of Trustees	Revised to address initial set of directives from Order 733	Revision (Project 2010-13)
2	March 15, 2012	FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)	
3	November 7, 2013	Adopted by NERC Board of Trustees	Supplemental SAR to Clarify applicability for consistency with PRC-025-1 and other minor corrections.

Version	Date	Action	Change Tracking
4	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
4	November 19, 2015	FERC Order issued approving PRC-023-4. Docket No. RM15-13-000.	

PRC-023-4 — Attachment A

1. This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:

1.1. Phase distance.

1.2. Out-of-step tripping.

1.3. Switch-on-to-fault.

1.4. Overcurrent relays.

1.5. Communications aided protection schemes including but not limited to:

1.5.1 Permissive overreach transfer trip (POTT).

1.5.2 Permissive under-reach transfer trip (PUTT).

1.5.3 Directional comparison blocking (DCB).

1.5.4 Directional comparison unblocking (DCUB).

1.6. Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.

2. The following protection systems are excluded from requirements of this standard:

2.1. Relay elements that are only enabled when other relays or associated systems fail. For example:

- Overcurrent elements that are only enabled during loss of potential conditions.
- Elements that are only enabled during a loss of communications except as noted in section 1.6.

2.2. Protection systems intended for the detection of ground fault conditions.

2.3. Protection systems intended for protection during stable power swings.

2.4. Not used.

2.5. Relay elements used only for Remedial Action Schemes applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017 or their successors.

2.6. Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.

2.7. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.

2.8. Relay elements associated with dc lines.

2.9. Relay elements associated with dc converter transformers.

PRC-023-4 — Attachment B

Circuits to Evaluate

- Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the Bulk Electric System.

Criteria

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

B1. The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.

B2. The circuit is selected by the Planning Coordinator based on Planning Assessments that identify instances of instability, Cascading, or uncontrolled separation.

B3. The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.

B4. The circuit is identified through the following sequence of power flow analyses[4] performed by the Planning Coordinator for the one-to-five-year planning horizon:

a. Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).

b. For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.

c. When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.

[4] Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

d. The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.

   i. If the Facility Rating is based on a loading duration of up to and including four hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.

   ii. If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.

   iii. If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.

e. Radially operated circuits serving only load are excluded.

B5. The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.

B6. The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard 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 initial ballot	June 2018 – July 2018
10-day final ballot	September 2018
NERC Board adoption	November 2018

A. Introduction

1. **Title:** **Relay Performance During Stable Power Swings**

2. **Number:** **PRC-026-2~~1~~**

3. **Purpose:** To ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Generator Owner that applies load-responsive protective relays as described in PRC-026-1 – Attachment A at the terminals of the Elements listed in Section 4.2, Facilities.

   4.1.2 Planning Coordinator.

   4.1.3 Transmission Owner that applies load-responsive protective relays as described in PRC-026-1 – Attachment A at the terminals of the Elements listed in Section 4.2, Facilities.

   4.2. Facilities: The following Elements that are part of the Bulk Electric System (BES):

   4.2.1 Generators.

   4.2.2 Transformers.

   4.2.3 Transmission lines.

5. **Background:**

   This is the third phase of a three-phased standard development project that focused on developing this new Reliability Standard to address protective relay operations due to stable power swings. The March 18, 2010, Federal Energy Regulatory Commission (FERC) Order No. 733 approved Reliability Standard PRC-023-1 – Transmission Relay Loadability. In that Order, FERC directed NERC to address three areas of relay loadability that include modifications to the approved PRC-023-1, development of a new Reliability Standard to address generator protective relay loadability, and a new Reliability Standard to address the operation of protective relays due to stable power swings. This project's SAR addresses these directives with a three-phased approach to standard development.

   Phase 1 focused on making the specific modifications from FERC Order No. 733 to PRC-023-1. Reliability Standard PRC-023-2, which incorporated these modifications, became mandatory on July 1, 2012.

   Phase 2 focused on developing a new Reliability Standard, PRC-025-1 – Generator Relay Loadability, to address generator protective relay loadability. PRC-025-1 became mandatory on October 1, 2014, along with PRC-023-3, which was modified to harmonize PRC-023-2 with PRC-025-1.

   Phase 3 focuses on preventing protective relays from tripping unnecessarily due to stable power swings by requiring identification of Elements on which a stable or unstable power

swing may affect Protection System operation, assessment of the security of load-responsive protective relays to tripping in response to only a stable power swing, and implementation of Corrective Action Plans (CAP), where necessary. Phase 3 improves security of load-responsive protective relays for stable power swings so they are expected to not trip in response to stable power swings during non-Fault conditions while maintaining dependable fault detection and dependable out-of-step tripping.

6. Effective Dates:

Requirement R1

First day of the first full calendar year that is 12 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first full calendar year that is 12 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Requirements R2, R3, and R4

First day of the first full calendar year that is 36 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first full calendar year 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.

B. Requirements and Measures

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

Criteria:

1. Generator(s) where an angular stability constraint exists that is addressed by a limiting the output of a generatorSystem Operating Limit (SOL) or a Remedial Action Scheme (RAS), and those Elements terminating at the Transmission station associated with the generator(s).
2. An Elements associated with that is monitored as part of an SOL identified by the Planning Coordinator's methodology[1] based on an angular instability identified in Planning Assessmentsconstraint.
3. An Element that forms the boundary of an island in the most recent underfrequency load shedding (UFLS) design assessment based on application of the Planning Coordinator's criteria for identifying islands, only if the island is formed by tripping the Element due to angular instability.
4. An Element identified in the most recent annual Planning Assessment where relay tripping occurs due to a stable or unstable[2] power swing during a simulated disturbance.

M1. Each Planning Coordinator shall have dated evidence that demonstrates notification of the generator, transformer, and transmission line BES Element(s) that meet one or more of the criteria in Requirement R1, if any, to the respective Generator Owner and Transmission Owner. Evidence may include, but is not limited to, the following documentation: emails, facsimiles, records, reports, transmittals, lists, or spreadsheets.

[1] NERC Reliability Standard FAC-014-2 – Establish and Communicate System Operating Limits, Requirement R3.

[2] An example of an unstable power swing is provided in the Guidelines and Technical Basis section, "Justification for Including Unstable Power Swings in the Requirements section of the Guidelines and Technical Basis."

R2. Each Generator Owner and Transmission Owner shall: [Violation Risk Factor: High] [Time Horizon: Operations Planning]

2.1 Within 12 full calendar months of notification of a BES Element pursuant to Requirement R1, determine whether its load-responsive protective relay(s) applied to that BES Element meets the criteria in PRC-026-1 – Attachment B where an evaluation of that Element's load-responsive protective relay(s) based on PRC-026-1 – Attachment B criteria has not been performed in the last five calendar years.

2.2 Within 12 full calendar months of becoming aware[3] of a generator, transformer, or transmission line BES Element that tripped in response to a stable or unstable[4] power swing due to the operation of its protective relay(s), determine whether its load-responsive protective relay(s) applied to that BES Element meets the criteria in PRC-026-1 – Attachment B.

M2. Each Generator Owner and Transmission Owner shall have dated evidence that demonstrates the evaluation was performed according to Requirement R2. Evidence may include, but is not limited to, the following documentation: apparent impedance characteristic plots, email, design drawings, facsimiles, R-X plots, software output, records, reports, transmittals, lists, settings sheets, or spreadsheets.

R3. Each Generator Owner and Transmission Owner shall, within six full calendar months of determining a load-responsive protective relay does not meet the PRC-026-1 – Attachment B criteria pursuant to Requirement R2, develop a Corrective Action Plan (CAP) to meet one of the following: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

- The Protection System meets the PRC-026-1 – Attachment B criteria, while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the BES Element); or
- The Protection System is excluded under the PRC-026-1 – Attachment A criteria (e.g., modifying the Protection System so that relay functions are supervised by power swing blocking or using relay systems that are immune to power swings), while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the BES Element).

M3. The Generator Owner and Transmission Owner shall have dated evidence that demonstrates the development of a CAP in accordance with Requirement R3. Evidence may include, but is not limited to, the following documentation: corrective action plans, maintenance records, settings sheets, project or work management program records, or work orders.

R4. Each Generator Owner and Transmission Owner shall implement each CAP developed pursuant to Requirement R3 and update each CAP if actions or timetables change until all actions are complete. *[Violation Risk Factor: Medium][Time Horizon: Long-Term Planning]*

M4. The Generator Owner and Transmission Owner shall have dated evidence that demonstrates implementation of each CAP according to Requirement R4, including updates to the CAP when actions or timetables change. Evidence may include, but is not limited to, the following documentation: corrective action plans, maintenance records, settings sheets, project or work management program records, or work orders.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

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

The Generator Owner, Planning Coordinator, and Transmission Owner shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

- The Planning Coordinator shall retain evidence of Requirement R1 for a minimum of one calendar year following the completion of the Requirement.
- The Generator Owner and Transmission Owner shall retain evidence of Requirement R2 evaluation for a minimum of 12 calendar months following completion of each evaluation where a CAP is not developed.
- The Generator Owner and Transmission Owner shall retain evidence of Requirements R2, R3, and R4 for a minimum of 12 calendar months following completion of each CAP.

If a Generator Owner, Planning Coordinator, or Transmission 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.

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[3] Some examples of the ways an entity may become aware of a power swing are provided in the Guidelines and Technical Basis section, "Becoming Aware of an Element That Tripped in Response to a Power Swing."

[4] An example of an unstable power swing is provided in the Guidelines and Technical Basis section, "Justification for Including Unstable Power Swings in the Requirements section of the Guidelines and Technical Basis."

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

As defined in the NERC Rules of Procedure; "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Medium	The Planning Coordinator provided notification of the BES Element(s) in accordance with Requirement R1, but was less than or equal to 30 calendar days late.	The Planning Coordinator provided notification of the BES Element(s) in accordance with Requirement R1, but was more than 30 calendar days and less than or equal to 60 calendar days late.	The Planning Coordinator provided notification of the BES Element(s) in accordance with Requirement R1, but was more than 60 calendar days and less than or equal to 90 calendar days late.	The Planning Coordinator provided notification of the BES Element(s) in accordance with Requirement R1, but was more than 90 calendar days late. OR The Planning Coordinator failed to provide notification of the BES Element(s) in accordance with Requirement R1.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Operations Planning	High	The Generator Owner or Transmission Owner evaluated its load-responsive protective relay(s) in accordance with Requirement R2, but was less than or equal to 30 calendar days late.	The Generator Owner or Transmission Owner evaluated its load-responsive protective relay(s) in accordance with Requirement R2, but was more than 30 calendar days and less than or equal to 60 calendar days late.	The Generator Owner or Transmission Owner evaluated its load-responsive protective relay(s) in accordance with Requirement R2, but was more than 60 calendar days and less than or equal to 90 calendar days late.	The Generator Owner or Transmission Owner evaluated its load-responsive protective relay(s) in accordance with Requirement R2, but was more than 90 calendar days late. OR The Generator Owner or Transmission Owner failed to evaluate its load-responsive protective relay(s) in accordance with Requirement R2.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	Long-term Planning	Medium	The Generator Owner or Transmission Owner developed a Corrective Action Plan (CAP) in accordance with Requirement R3, but in more than six calendar months and less than or equal to seven calendar months.	The Generator Owner or Transmission Owner developed a Corrective Action Plan (CAP) in accordance with Requirement R3, but in more than seven calendar months and less than or equal to eight calendar months.	The Generator Owner or Transmission Owner developed a Corrective Action Plan (CAP) in accordance with Requirement R3, but in more than eight calendar months and less than or equal to nine calendar months.	The Generator Owner or Transmission Owner developed a Corrective Action Plan (CAP) in accordance with Requirement R3, but in more than nine calendar months. OR The Generator Owner or Transmission Owner failed to develop a CAP in accordance with Requirement R3.
R4	Long-term Planning	Medium	The Generator Owner or Transmission Owner implemented a Corrective Action Plan (CAP), but failed to update a CAP when actions or timetables changed, in accordance with Requirement R4.	N/A	N/A	The Generator Owner or Transmission Owner failed to implement a Corrective Action Plan (CAP) in accordance with Requirement R4.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

Applied Protective Relaying, Westinghouse Electric Corporation, 1979.

Burdy, John, *Loss-of-excitation Protection for Synchronous Generators GER-3183*, General Electric Company.

IEEE Power System Relaying Committee WG D6, *Power Swing and Out-of-Step Considerations on Transmission Lines*, July 2005: http://www.pes-psrc.org/Reports/Power%20Swing%20and%20OOS%20Considerations%20on%20Transmission%20Lines%20F..pdf.

Kimbark Edward Wilson, *Power System Stability, Volume II: Power Circuit Breakers and Protective Relays*, Published by John Wiley and Sons, 1950.

Kundur, Prabha, *Power System Stability and Control*, 1994, Palo Alto: EPRI, McGraw Hill, Inc.

NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf.

Reimert, Donald, *Protective Relaying for Power Generation Systems*, 2006, Boca Raton: CRC Press.

Version History

Version	Date	Action	Change Tracking
1	November 13, 2014	Adopted by NERC Board of Trustees	New
1	March 17, 2016	FERC Order issued approving PRC-026-1. Docket No. RM15-8-000.	

PRC-026-1 – Attachment A

This standard applies to any protective functions which could trip instantaneously or with a time delay of less than 15 cycles on load current (i.e., "load-responsive") including, but not limited to:

- Phase distance
- Phase overcurrent
- Out-of-step tripping
- Loss-of-field

The following protection functions are excluded from Requirements of this standard:

- Relay elements supervised by power swing blocking
- Relay elements that are only enabled when other relays or associated systems fail. For example:
    - Overcurrent elements that are only enabled during loss of potential conditions.
    - Relay elements that are only enabled during a loss of communications
- Thermal emulation relays which are used in conjunction with dynamic Facility Ratings
- Relay elements associated with direct current (dc) lines
- Relay elements associated with dc converter transformers
- Phase fault detector relay elements employed to supervise other load-responsive phase distance elements (i.e., in order to prevent false operation in the event of a loss of potential)
- Relay elements associated with switch-onto-fault schemes
- Reverse power relay on the generator
- Generator 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)
- Current differential relay, pilot wire relay, and phase comparison relay
- Voltage-restrained or voltage-controlled overcurrent relays

PRC-026-1 – Attachment B

Criterion A:

An impedance-based relay used for tripping is expected to not trip for a stable power swing, when the relay characteristic is completely contained within the unstable power swing region.[5] The unstable power swing region is formed by the union of three shapes in the impedance (R-X) plane; (1) a lower loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 0.7; (2) an upper loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 1.43; (3) a lens that connects the endpoints of the total system impedance (with the parallel transfer impedance removed) bounded by varying the sending-end and receiving-end voltages from 0.0 to 1.0 per unit, while maintaining a constant system separation angle across the total system impedance where:

1. The system separation angle is:
   - At least 120 degrees, or
   - An angle less than 120 degrees where a documented transient stability analysis demonstrates that the expected maximum stable separation angle is less than 120 degrees.
2. All generation is in service and all transmission BES Elements are in their normal operating state when calculating the system impedance.
3. Saturated (transient or sub-transient) reactance is used for all machines.

[5] Guidelines and Technical Basis, Figures 1 and 2.

PRC-026-1 – Attachment B

Criterion B:

The pickup of an overcurrent relay element used for tripping, that is above the calculated current value (with the parallel transfer impedance removed) for the conditions below:

1. The system separation angle is:
   - At least 120 degrees, or
   - An angle less than 120 degrees where a documented transient stability analysis demonstrates that the expected maximum stable separation angle is less than 120 degrees.
2. All generation is in service and all transmission BES Elements are in their normal operating state when calculating the system impedance.
3. Saturated (transient or sub-transient) reactance is used for all machines.
4. Both the sending-end and receiving-end voltages at 1.05 per unit.

Guidelines and Technical Basis

Introduction

The NERC System Protection and Control Subcommittee technical document, *Protection System Response to Power Swings*, August 2013,[6] ("PSRPS Report" or "report") was specifically prepared to support the development of this NERC Reliability Standard. The report provided a historical perspective on power swings as early as 1965 up through the approval of the report by the NERC Planning Committee. The report also addresses reliability issues regarding trade-offs between security and dependability of Protection Systems, considerations for this NERC Reliability Standard, and a collection of technical information about power swing characteristics and varying issues with practical applications and approaches to power swings. Of these topics, the report suggests an approach for this NERC Reliability Standard ("standard" or "PRC-026-1") which is consistent with addressing three regulatory directives in the FERC Order No. 733. The first directive concerns the need for "…protective relay systems that differentiate between faults and stable power swings and, when necessary, phases out protective relay systems that cannot meet this requirement."[7] Second, is "…to develop a Reliability Standard addressing undesirable relay operation due to stable power swings."[8] The third directive "…to consider "islanding" strategies that achieve the fundamental performance for all islands in developing the new Reliability Standard addressing stable power swings"[9] was considered during development of the standard.

The development of this standard implements the majority of the approaches suggested by the report. However, it is noted that the Reliability Coordinator and Transmission Planner have not been included in the standard's Applicability section (as suggested by the PSRPS Report). This is so that a single entity, the Planning Coordinator, may be the single source for identifying Elements according to Requirement R1. A single source will insure that multiple entities will not identify Elements in duplicate, nor will one entity fail to provide an Element because it believes the Element is being provided by another entity. The Planning Coordinator has, or has access to, the wide-area model and can correctly identify the Elements that may be susceptible to a stable or unstable power swing. Additionally, not including the Reliability Coordinator and Transmission Planner is consistent with the applicability of other relay loadability NERC Reliability Standards (e.g., PRC-023 and PRC-025). It is also consistent with the NERC Functional Model.

The phrase, "while maintaining dependable fault detection and dependable out-of-step tripping" in Requirement R3, describes that the Generator Owner and Transmission Owner are 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

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[6] NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

[7] Transmission Relay Loadability Reliability Standard, Order No. 733, P.150 FERC ¶ 61,221 (2010).

[8] Ibid. P.153.

[9] Ibid. P.162.

this standard is not intended to result in the loss of these protection functions. Instead, the Generator Owner and Transmission Owner must consider both the Requirements within this standard and its desired protection goals and perform modifications to its protective relays or protection philosophies as necessary to achieve both.

Power Swings

The IEEE Power System Relaying Committee WG D6 developed a technical document called *Power Swing and Out-of-Step Considerations on Transmission Lines* (July 2005) that provides background on power swings. The following are general definitions from that document:[10]

> Power Swing: a variation in three phase power flow which occurs when the generator rotor angles are advancing or retarding relative to each other in response to changes in load magnitude and direction, line switching, loss of generation, faults, and other system disturbances.
>
> Pole Slip: a condition whereby a generator, or group of generators, terminal voltage angles (or phases) go past 180 degrees with respect to the rest of the connected power system.
>
> Stable Power Swing: a power swing is considered stable if the generators do not slip poles and the system reaches a new state of equilibrium, i.e. an acceptable operating condition.
>
> Unstable Power Swing: a power swing that will result in a generator or group of generators experiencing pole slipping for which some corrective action must be taken.
>
> Out-of-Step Condition: Same as an unstable power swing.
>
> Electrical System Center or Voltage Zero: it is the point or points in the system where the voltage becomes zero during an unstable power swing.

Burden to Entities

The PSRPS Report provides a technical basis and approach for focusing on Protection Systems, which are susceptible to power swings, while achieving the purpose of the standard. The approach reduces the number of relays to which the PRC-026-1 Requirements would apply by first identifying the BES Element(s) on which load-responsive protective relays must be evaluated. The first step uses criteria to identify the Elements on which a Protection System is expected to be challenged by power swings. Of those Elements, the second step is to evaluate each load-responsive protective relay that is applied on each identified Element. Rather than requiring the Planning Coordinator or Transmission Planner to perform simulations to obtain information for each identified Element, the Generator Owner and Transmission Owner will reduce the need for simulation by comparing the load-responsive protective relay characteristic to specific criteria in PRC-026-1 – Attachment B.

[10] http://www.pes-psrc.org/Reports/Power%20Swing%20and%20OOS%20Considerations%20on%20Transmission%20Lines%20F..pdf.

Applicability

The standard is applicable to the Generator Owner, Planning Coordinator, and Transmission Owner entities. More specifically, the Generator Owner and Transmission Owner entities are applicable when applying load-responsive protective relays at the terminals of the applicable BES Elements. The standard is applicable to the following BES Elements: generators, transformers, and transmission lines. The Distribution Provider was considered for inclusion in the standard; however, it is not subject to the standard because this entity, by functional registration, would not own generators, transmission lines, or transformers other than load serving.

Load-responsive protective relays include any protective functions which could trip with or without time delay, on load current.

Requirement R1

The Planning Coordinator has a wide-area view and is in the position to identify what, if any, Elements meet the criteria. The criterion-based approach is consistent with the NERC System Protection and Control Subcommittee (SPCS) technical document, *Protection System Response to Power Swings (*August 2013),[11] which recommends a focused approach to determine an at-risk Element. Identification of Elements comes from the annual Planning Assessments pursuant to the transmission planning (i.e., "TPL") and other NERC Reliability Standards (e.g., PRC-006), and the standard is not requiring any other assessments to be performed by the Planning Coordinator. The required notification on a calendar year basis to the respective Generator Owner and Transmission Owner is sufficient because it is expected that the Planning Coordinator will make its notifications following the completion of its annual Planning Assessments. The Planning Coordinator will continue to provide notification of Elements on a calendar year basis even if a study is performed less frequently (e.g., PRC-006 – Automatic Underfrequency Load Shedding, which is five years) and has not changed. It is possible that a Planning Coordinator could utilize studies from a prior year in determining the necessary notifications pursuant to Requirement R1.

Criterion 1

The first criterion involves generator(s) where an angular stability constraint exists that is addressed by limiting the output of a generator~~a System Operating Limit (SOL)~~ or a Remedial Action Scheme (RAS) and those Elements terminating at the Transmission station associated with the generator(s). For example, a scheme to remove generation for specific conditions is implemented for a four-unit generating plant (1,100 MW). Two of the units are 500 MW each; one is connected to the 345 kV system and one is connected to the 230 kV system. The Transmission Owner has two 230 kV transmission lines and one 345 kV transmission line all terminating at the generating facility as well as a 345/230 kV autotransformer. The remaining 100 MW consists of two 50 MW combustion turbine (CT) units connected to four 66 kV transmission lines. The 66 kV transmission lines are not electrically joined to the 345 kV and 230 kV transmission lines at the plant site and are not subject to ~~the operating limit~~ any generating output limitation or RAS. A

[11] http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

stability constraint limits the output of the portion of the plant affected by the RAS to 700 MW for an outage of the 345 kV transmission line. The RAS trips one of the 500 MW units to maintain stability for a loss of the 345 kV transmission line when the total output from both 500 MW units is above 700 MW. For this example, both 500 MW generating units and the associated generator step-up (GSU) transformers would be identified as Elements meeting this criterion. The 345/230 kV autotransformer, the 345 kV transmission line, and the two 230 kV transmission lines would also be identified as Elements meeting this criterion. The 50 MW combustion turbines and 66 kV transmission lines would not be identified pursuant to Criterion 1 because these Elements are not subject to ~~an operating limit~~ any generating output limitation or RAS and do not terminate at the Transmission station associated with the generators that are subject to any generating output limitation~~the SOL~~ or RAS.

Criterion 2

The second criterion involves Elements associated with angular instability identified in the Planning Assessments~~that are monitored as a part of an established System Operating Limit (SOL) based on an angular stability limit regardless of the outage conditions that result in the enforcement of the SOL~~. For example, if Planning Assessments have identified that an angular instability could limit transfer capability on two long parallel 500 kV transmission lines ~~have a combined SOL of~~ to a maximum of 1,200 MW, and this limitation is based on angular instability resulting from a fault and subsequent loss of one of the two lines, then both lines would be identified as Elements meeting the criterion.

Criterion 3

The third criterion involves Elements that form the boundary of an island within an underfrequency load shedding (UFLS) design assessment. The criterion applies to islands identified based on application of the Planning Coordinator's criteria for identifying islands, where the island is formed by tripping the Elements based on angular instability. The criterion applies if the angular instability is modeled in the UFLS design assessment, or if the boundary is identified "off-line" (i.e., the Elements are selected based on angular instability considerations, but the Elements are tripped in the UFLS design assessment without modeling the initiating angular instability). In cases where an out-of-step condition is detected and tripping is initiated at an alternate location, the criterion applies to the Element on which the power swing is detected. The criterion does not apply to islands identified based on other considerations that do not involve angular instability, such as excessive loading, Planning Coordinator area boundary tie lines, or Balancing Authority boundary tie lines.

Criterion 4

The fourth criterion involves Elements identified in the most recent annual Planning Assessment where relay tripping occurs due to a stable or unstable[12] power swing during a simulated

[12] Refer to the "Justification for Including Unstable Power Swings in the Requirements" section.

disturbance. The intent is for the Planning Coordinator to include any Element(s) where relay tripping was observed during simulations performed for the most recent annual Planning Assessment associated with the transmission planning TPL-001-4 Reliability Standard. Note that relay tripping must be assessed within those annual Planning Assessments per TPL-001-4, R4, Part 4.3.1.3, which indicates that analysis shall include the "Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models." Identifying such Elements according to Criterion 4 and notifying the respective Generator Owner and Transmission Owner will require that the owners of any load-responsive protective relay applied at the terminals of the identified Element evaluate the relay's susceptibility to tripping in response to a stable power swing.

Planning Coordinators have the discretion to determine whether the observed tripping for a power swing in its Planning Assessments occurs for valid contingencies and system conditions. The Planning Coordinator will address tripping that is observed in transient analyses on an individual basis; therefore, the Planning Coordinator is responsible for identifying the Elements based only on simulation results that are determined to be valid.

Due to the nature of how a Planning Assessment is performed, there may be cases where a previously-identified Element is not identified in the most recent annual Planning Assessment. If so, this is acceptable because the Generator Owner and Transmission Owner would have taken action upon the initial notification of the previously identified Element. When an Element is not identified in later Planning Assessments, the risk of load-responsive protective relays tripping in response to a stable power swing during non-Fault conditions would have already been assessed under Requirement R2 and mitigated according to Requirements R3 and R4 where the relays did not meet the PRC-026-1 – Attachment B criteria. According to Requirement R2, the Generator Owner and Transmission Owner are only required to re-evaluate each load-responsive protective relay for an identified Element where the evaluation has not been performed in the last five calendar years.

Although Requirement R1 requires the Planning Coordinator to notify the respective Generator Owner and Transmission Owner of any Elements meeting one or more of the four criteria, it does not preclude the Planning Coordinator from providing additional information, such as apparent impedance characteristics, in advance or upon request, that may be useful in evaluating protective relays. Generator Owners and Transmission Owners are able to complete protective relay evaluations and perform the required actions without additional information. The standard does not include any requirement for the entities to provide information that is already being shared or exchanged between entities for operating needs. While a Requirement has not been included for the exchange of information, entities should recognize that relay performance needs to be measured against the most current information.

Requirement R2

Requirement R2 requires the Generator Owner and Transmission Owner to evaluate its load-responsive protective relays to ensure that they are expected to not trip in response to stable power swings.

The PRC-026-1 – Attachment A lists the applicable load-responsive relays that must be evaluated which include phase distance, phase overcurrent, out-of-step tripping, and loss-of-field relay functions. Phase distance relays could include, but are not limited to, the following:

- Zone elements with instantaneous tripping or intentional time delays of less than 15 cycles
- Phase distance elements used in high-speed communication-aided tripping schemes including:
  - Directional Comparison Blocking (DCB) schemes
  - Directional Comparison Un-Blocking (DCUB) schemes
  - Permissive Overreach Transfer Trip (POTT) schemes
  - Permissive Underreach Transfer Trip (PUTT) schemes

A method is provided within the standard to support consistent evaluation by Generator Owners and Transmission Owners based on specified conditions. Once a Generator Owner or Transmission Owner is notified of Elements pursuant to Requirement R1, it has 12 full calendar months to determine if each Element's load-responsive protective relays meet the PRC-026-1 – Attachment B criteria, if the determination has not been performed in the last five calendar years. Additionally, each Generator Owner and Transmission Owner, that becomes aware of a generator, transformer, or transmission line BES Element that tripped in response to a stable or unstable power swing due to the operation of its protective relays pursuant to Requirement R2, Part 2.2, must perform the same PRC-026-1 – Attachment B criteria determination within 12 full calendar months.

Becoming Aware of an Element That Tripped in Response to a Power Swing

Part 2.2 in Requirement R2 is intended to initiate action by the Generator Owner and Transmission Owner when there is a known stable or unstable power swing and it resulted in the entity's Element tripping. The criterion starts with becoming aware of the event (i.e., power swing) and then any connection with the entity's Element tripping. By doing so, the focus is removed from the entity having to demonstrate that it made a determination whether a power swing was present for every Element trip. The basis for structuring the criterion in this manner is driven by the available ways that a Generator Owner and Transmission Owner could become aware of an Element that tripped in response to a stable or unstable power swing due to the operation of its protective relay(s).

Element trips caused by stable or unstable power swings, though infrequent, would be more common in a larger event. The identification of power swings will be revealed during an analysis of the event. Event analysis where an entity may become aware of a stable or unstable power swing could include internal analysis conducted by the entity, the entity's Protection System review following a trip, or a larger scale analysis by other entities. Event analysis could include involvement by the entity's Regional Entity, and in some cases NERC.

Information Common to Both Generation and Transmission Elements

The PRC-026-1 – Attachment A lists the load-responsive protective relays that are subject to this standard. Generator Owners and Transmission Owners may own load-responsive protective relays (e.g., distance relays) that directly affect generation or transmission BES Elements and will require analysis as a result of Elements being identified by the Planning Coordinator in Requirement R1

or the Generator Owner or Transmission Owner in Requirement R2. For example, distance relays owned by the Transmission Owner may be installed at the high-voltage side of the generator step-up (GSU) transformer (directional toward the generator) providing backup to generation protection. Generator Owners may have distance relays applied to backup transmission protection or backup protection to the GSU transformer. The Generator Owner may have relays installed at the generator terminals or the high-voltage side of the GSU transformer.

Exclusion of Time Based Load-Responsive Protective Relays

The purpose of the standard is "[t]o ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions." Load-responsive, high-speed tripping protective relays pose the highest risk of operating during a power swing. Because of this, high-speed tripping protective relays and relays with a time delay of less than 15 cycles are included in the standard; whereas other relays (i.e., Zones 2 and 3) with a time delay of 15 cycles or greater are excluded. The time delay used for exclusion on some load-responsive protective relays is based on the maximum expected time that load-responsive protective relays would be exposed to a stable power swing with a slow slip rate frequency.

In order to establish a time delay that distinguishes a high-risk load-responsive protective relay from one that has a time delay for tripping (lower-risk), a sample of swing rates were calculated based on a stable power swing entering and leaving the impedance characteristic as shown in Table 1. For a relay impedance characteristic that has a power swing entering and leaving, beginning at 90 degrees with a termination at 120 degrees before exiting the zone, the zone timer must be greater than the calculated time the stable power swing is inside the relay's operating zone to not trip in response to the stable power swing.

Eq. (1) $$Zone\ timer > 2 \times \left(\frac{(120° - Angle\ of\ entry\ into\ the\ relay\ characteristic) \times 60}{(360 \times Slip\ Rate)}\right)$$

Table 1: Swing Rates

Zone Timer (Cycles)	Slip Rate (Hz)
10	1.00
15	0.67
20	0.50
30	0.33

With a minimum zone timer of 15 cycles, the corresponding slip rate of the system is 0.67 Hz. This represents an approximation of a slow slip rate during a system Disturbance. Longer time delays allow for slower slip rates.

Application to Transmission Elements

Criterion A in PRC-026-1 – Attachment B describes an unstable power swing region that is formed by the union of three shapes in the impedance (R-X) plane. The first shape is a lower loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 0.7 (i.e., E_S / E_R = 0.7 / 1.0 = 0.7). The second shape is an upper loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 1.43 (i.e., E_S / E_R = 1.0 / 0.7 = 1.43). The third shape is a lens that connects the endpoints of the total system impedance together by varying the sending-end and receiving-end system voltages from 0.0 to 1.0 per unit, while maintaining a constant system separation angle across the total system impedance (with the parallel transfer impedance removed—see Figures 1 through 5). The total system impedance is derived from a two-bus equivalent network and is determined by summing the sending-end source impedance, the line impedance (excluding the Thévenin equivalent transfer impedance), and the receiving-end source impedance as shown in Figures 6 and 7. Establishing the total system impedance provides a conservative condition that will maximize the security of the relay against various system conditions. The smallest total system impedance represents a condition where the size of the lens characteristic in the R-X plane is smallest and is a conservative operating point from the standpoint of ensuring a load-responsive protective relay is expected to not trip given a predetermined angular displacement between the sending-end and receiving-end voltages. The smallest total system impedance results when all generation is in service and all transmission BES Elements are modeled in their "normal" system configuration (PRC-026-1 – Attachment B, Criterion A). The parallel transfer impedance is removed to represent a likely condition where parallel Elements may be lost during the disturbance, and the loss of these Elements magnifies the sensitivity of the load-responsive relays on the parallel line by removing the "infeed effect" (i.e., the apparent impedance sensed by the relay is decreased as a result of the loss of the transfer impedance, thus making the relay more likely to trip for a stable power swing—See Figures 13 and 14).

The sending-end and receiving-end source voltages are varied from 0.7 to 1.0 per unit to form the lower and upper loss-of-synchronism circles. The ratio of these two voltages is used in the calculation of the loss-of-synchronism circles, and result in a ratio range from 0.7 to 1.43.

Eq. (2) $$\frac{E_S}{E_R} = \frac{0.7}{1.0} = 0.7$$

Eq. (3): $$\frac{E_S}{E_R} = \frac{1.0}{0.7} = 1.43$$

The internal generator voltage during severe power swings or transmission system fault conditions will be greater than zero due to voltage regulator support. The voltage ratio of 0.7 to 1.43 is chosen to be more conservative than the PRC-023[13] and PRC-025[14] NERC Reliability Standards where a lower bound voltage of 0.85 per unit voltage is used. A ±15% internal generator voltage range was chosen as a conservative voltage range for calculation of the voltage ratio used to calculate the loss-of-synchronism circles. For example, the voltage ratio using these voltages would result in a ratio range from 0.739 to 1.353.

[13] Transmission Relay Loadability

[14] Generator Relay Loadability

Eq. (4) $$\frac{E_S}{E_R} = \frac{0.85}{1.15} = 0.739$$ Eq. (5): $$\frac{E_S}{E_R} = \frac{1.15}{0.85} = 1.353$$

The lower ratio is rounded down to 0.7 to be more conservative, allowing a voltage range of 0.7 to 1.0 per unit to be used for the calculation of the loss-of-synchronism circles.[15]

When the parallel transfer impedance is included in the model, the division of current through the parallel transfer impedance path results in actual measured relay impedances that are larger than those measured when the parallel transfer impedance is removed (i.e., infeed effect), which would make it more likely for an impedance relay element to be completely contained within the unstable power swing region as shown in Figure 11. If the transfer impedance is included in the evaluation, a distance relay element could be deemed as meeting PRC-026-1 – Attachment B criteria and, in fact would be secure, assuming all Elements were in their normal state. In this case, the distance relay element could trip in response to a stable power swing during an actual event if the system was weakened (i.e., a higher transfer impedance) by the loss of a subset of lines that make up the parallel transfer impedance as shown in Figure 10. This could happen because the subset of lines that make up the parallel transfer impedance tripped on unstable swings, contained the initiating fault, and/or were lost due to operation of breaker failure or remote back-up protection schemes.

Table 10 shows the percent size increase of the lens shape as seen by the relay under evaluation when the parallel transfer impedance is included. The parallel transfer impedance has minimal effect on the apparent size of the lens shape as long as the parallel transfer impedance is at least 10 multiples of the parallel line impedance (less than 5% lens shape expansion), therefore, its removal has minimal impact, but results in a slightly more conservative, smaller lens shape. Parallel transfer impedances of 5 multiples of the parallel line impedance or less result in an apparent lens shape size of 10% or greater as seen by the relay. If two parallel lines and a parallel transfer impedance tie the sending-end and receiving-end buses together, the total parallel transfer impedance will be one or less multiples of the parallel line impedance, resulting in an apparent lens shape size of 45% or greater. It is a realistic contingency that the parallel line could be out-of-service, leaving the parallel transfer impedance making up the rest of the system in parallel with the line impedance. Since it is not known exactly which lines making up the parallel transfer impedance will be out of service during a major system disturbance, it is most conservative to assume that all of them are out, leaving just the line under evaluation in service.

Either the saturated transient or sub-transient direct axis reactance may be used for machines in the evaluation because they are smaller than the un-saturated reactances. Since saturated sub-transient generator reactances are smaller than the transient or synchronous reactances, the use of sub-transient reactances will result in a smaller source impedance and a smaller unstable power swing region in the graphical analysis as shown in Figures 8 and 9. Because power swings occur in a time frame where generator transient reactances will be prevalent, it is acceptable to use saturated transient reactances instead of saturated sub-transient reactances. Because some short-

[15] *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, April 2004, Section 6 (The Cascade Stage of the Blackout), p. 94 under "Why the Generators Tripped Off," states, "Some generator undervoltage relays were set to trip at or above 90% voltage. However, a motor stalls out at about 70% voltage and a motor starter contactor drops out around 75%, so if there is a compelling need to protect the turbine from the system the under-voltage trigger point should be no higher than 80%."

circuit models may not include transient reactances, the use of sub-transient reactances is also acceptable because it produces more conservative results. For this reason, either value is acceptable when determining the system source impedances (PRC-026-1 – Attachment B, Criterion A and B, No. 3).

Saturated reactances are used in short-circuit programs that produce the system impedance mentioned above. Planning and stability software generally use un-saturated reactances. Generator models used in transient stability analyses recognize that the extent of the saturation effect depends upon both rotor (field) and stator currents. Accordingly, they derive the effective saturated parameters of the machine at each instant by internal calculation from the specified (constant) unsaturated values of machine reactances and the instantaneous internal flux level. The specific assumptions regarding which inductances are affected by saturation, and the relative effect of that saturation, are different for the various generator models used. Thus, unsaturated values of all machine reactances are used in setting up planning and stability software data, and the appropriate set of open-circuit magnetization curve data is provided for each machine.

Saturated reactance values are smaller than unsaturated reactance values and are used in short-circuit programs owned by the Generator and Transmission Owners. Because of this, saturated reactance values are to be used in the development of the system source impedances.

The source or system equivalent impedances can be obtained by a number of different methods using commercially available short-circuit calculation tools.[16] Most short-circuit tools have a network reduction feature that allows the user to select the local and remote terminal buses to retain. The first method reduces the system to one that contains two buses, an equivalent generator at each bus (representing the source impedances at the sending-end and receiving-end), and two parallel lines; one being the line impedance of the protected line with relays being analyzed, the other being the parallel transfer impedance representing all other combinations of lines that connect the two buses together as shown in Figure 6. Another conservative method is to open both ends of the line being evaluated, and apply a three-phase bolted fault at each bus to determine the Thévenin equivalent impedance at each bus. The source impedances are set equal to the Thévenin equivalent impedances and will be less than or equal to the actual source impedances calculated by the network reduction method. Either method can be used to develop the system source impedances at both ends.

The two bullets of PRC-026-1 – Attachment B, Criterion A, No. 1, identify the system separation angles used to identify the size of the power swing stability boundary for evaluating load-responsive protective relay impedance elements. The first bullet of PRC-026-1 – Attachment B, Criterion A, No. 1 evaluates a system separation angle of at least 120 degrees that is held constant while varying the sending-end and receiving-end source voltages from 0.7 to 1.0 per unit, thus creating an unstable power swing region about the total system impedance in Figure 1. This unstable power swing region is compared to the tripping portion of the distance relay characteristic; that is, the portion that is not supervised by load encroachment, blinders, or some other form of supervision as shown in Figure 12 that restricts the distance element from tripping

[16] Demetrios A. Tziouvaras and Daqing Hou, Appendix in *Out-Of-Step Protection Fundamentals and Advancements,* April 17, 2014: https://www.selinc.com.

for heavy, balanced load conditions. If the tripping portion of the impedance characteristics are completely contained within the unstable power swing region, the relay impedance element meets Criterion A in PRC-026-1 – Attachment B. A system separation angle of 120 degrees was chosen for the evaluation because it is generally accepted in the industry that recovery for a swing beyond this angle is unlikely to occur.[17]

The second bullet of PRC-026-1 – Attachment B, Criterion A, No. 1 evaluates impedance relay elements at a system separation angle of less than 120 degrees, similar to the first bullet described above. An angle less than 120 degrees may be used if a documented stability analysis demonstrates that the power swing becomes unstable at a system separation angle of less than 120 degrees.

The exclusion of relay elements supervised by Power Swing Blocking (PSB) in PRC-026-1 – Attachment A allows the Generator Owner or Transmission Owner to exclude protective relay elements if they are blocked from tripping by PSB relays. A PSB relay applied and set according to industry accepted practices prevent supervised load-responsive protective relays from tripping in response to power swings. Further, PSB relays are set to allow dependable tripping of supervised elements. The criteria in PRC-026-1 – Attachment B specifically applies to unsupervised elements that could trip for stable power swings. Therefore, load-responsive protective relay elements supervised by PSB can be excluded from the Requirements of this standard.

[17] "The critical angle for maintaining stability will vary depending on the contingency and the system condition at the time the contingency occurs; however, the likelihood of recovering from a swing that exceeds 120 degrees is marginal and 120 degrees is generally accepted as an appropriate basis for setting out-of-step protection. Given the importance of separating unstable systems, defining 120 degrees as the critical angle is appropriate to achieve a proper balance between dependable tripping for unstable power swings and secure operation for stable power swings." NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf), p. 28.

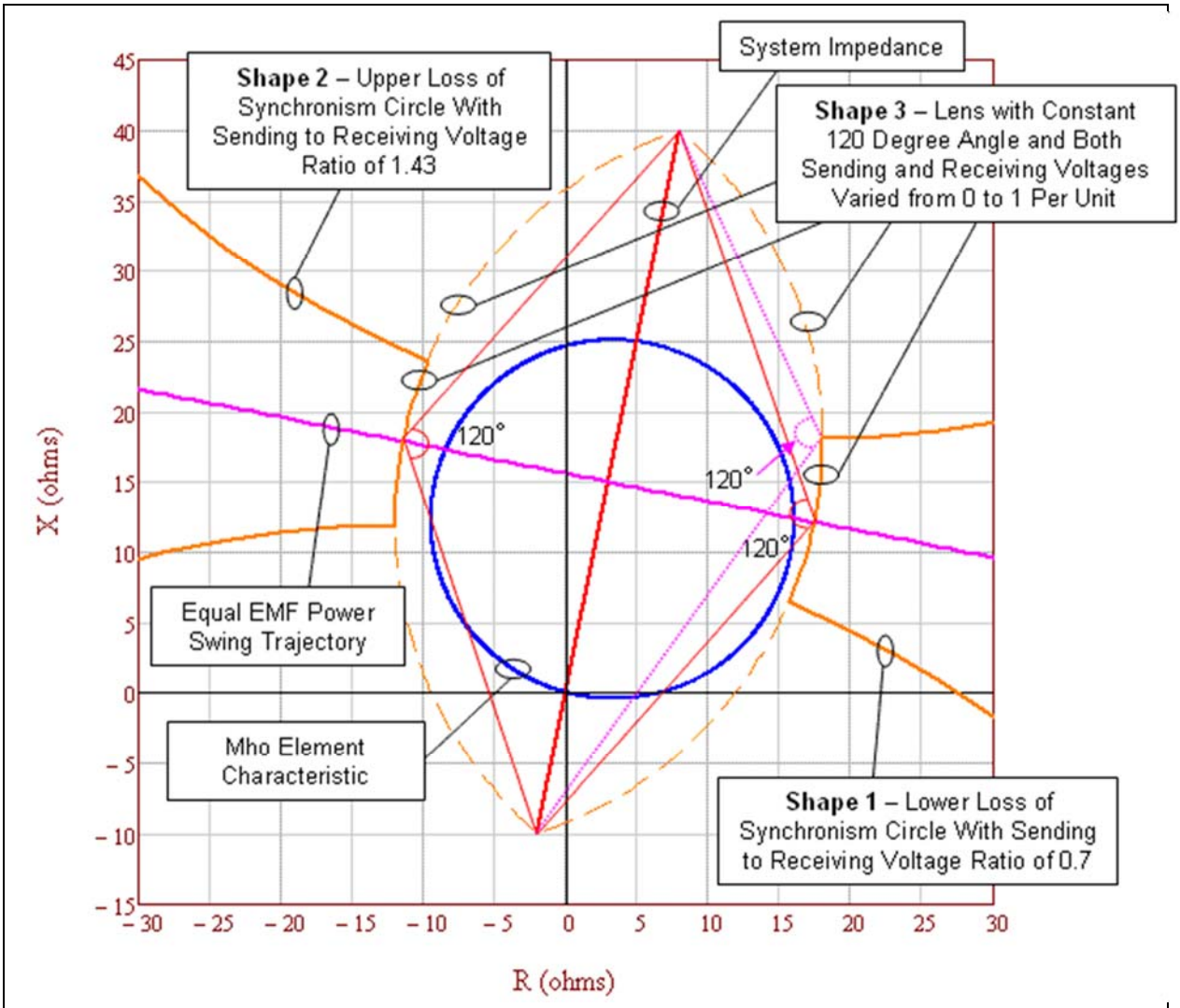

Figure 1: An enlarged graphic illustrating the unstable power swing region formed by the union of three shapes in the impedance (R-X) plane: Shape 1) Lower loss-of-synchronism circle, Shape 2) Upper loss-of-synchronism circle, and Shape 3) Lens. The mho element characteristic is completely contained within the unstable power swing region (i.e., it does not intersect any portion of the unstable power swing region), therefore it meets PRC-026-1 – Attachment B, Criterion A, No. 1.

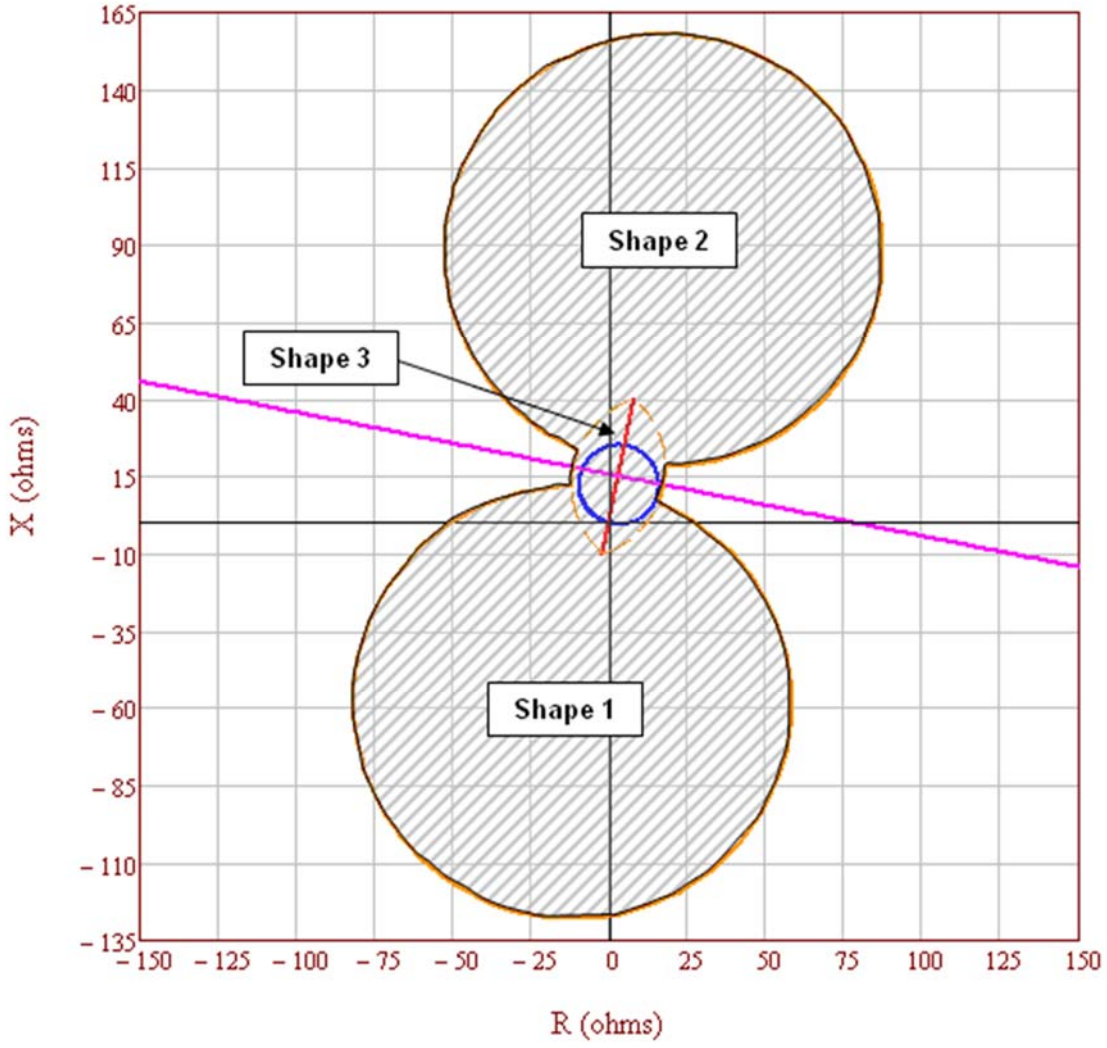

Figure 2: Full graphic of the unstable power swing region formed by the union of the three shapes in the impedance (R-X) plane: Shape 1) Lower loss-of-synchronism circle, Shape 2) Upper loss-of-synchronism circle, and Shape 3) Lens. The mho element characteristic is completely contained within the unstable power swing region, therefore it meets PRC-26-1 – Attachment B, Criterion A, No.1.

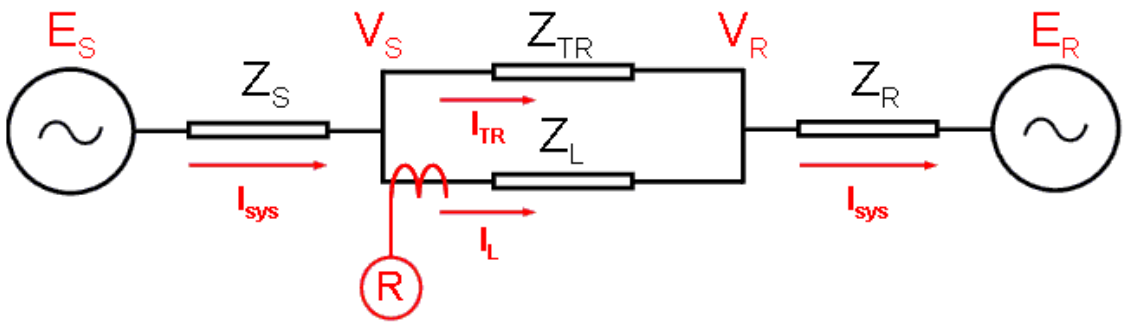

Figure 3: System impedances as seen by Relay R (voltage connections are not shown).

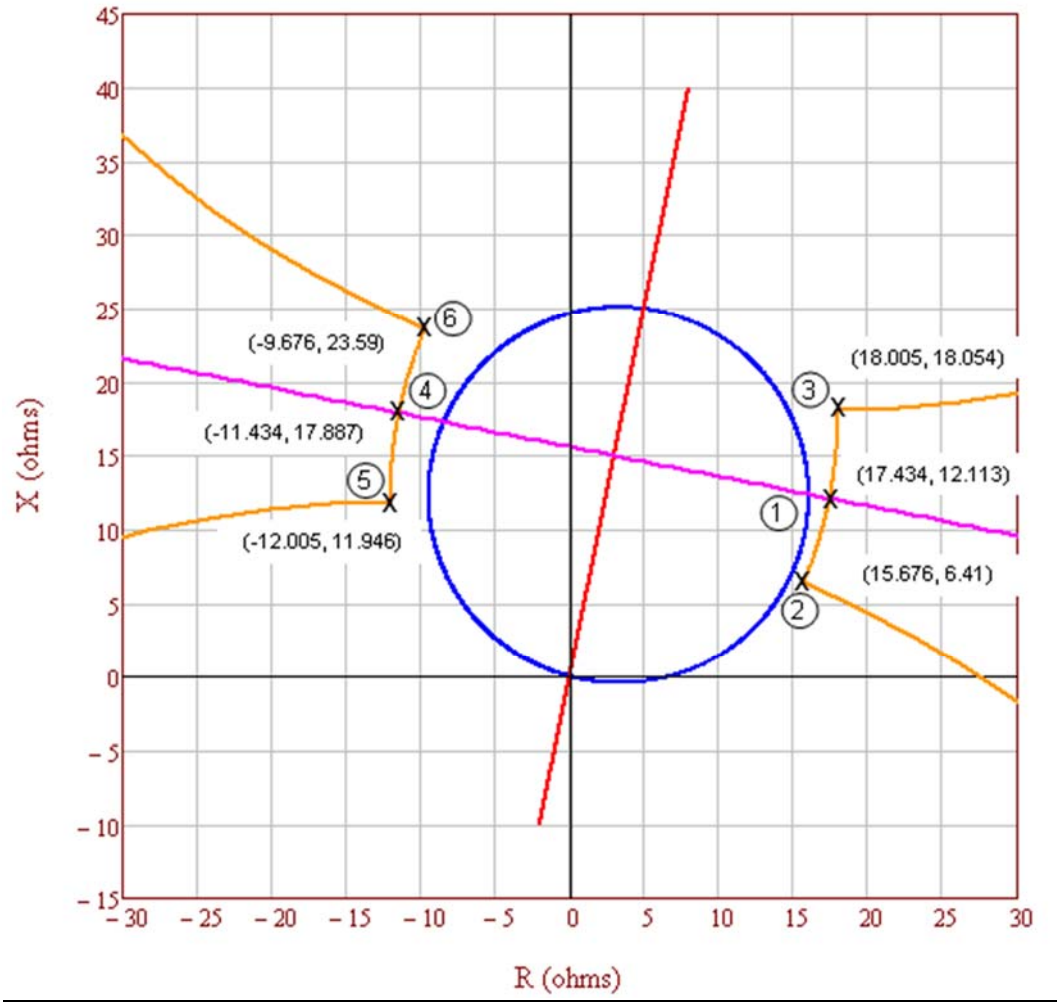

Figure 4: The defining unstable power swing region points where the lens shape intersects the lower and upper loss-of-synchronism circle shapes and where the lens intersects the equal EMF (electromotive force) power swing.

	Left Side Coordinates		Right Side Coordinates	
E_S / E_R Voltage Ratio	R	+ jX	R	+ jX
0.7	**-12.005**	**11.946**	**15.676**	**6.41**
0.72	-12.004	12.407	15.852	6.836
0.74	-11.996	12.857	16.018	7.255
0.76	-11.982	13.298	16.175	7.667
0.78	-11.961	13.729	16.321	8.073
0.8	-11.935	14.151	16.459	8.472
0.82	-11.903	14.563	16.589	8.865
0.84	-11.867	14.966	16.71	9.251
0.86	-11.826	15.361	16.824	9.631
0.88	-11.78	15.746	16.93	10.004
0.9	-11.731	16.123	17.03	10.371
0.92	-11.678	16.492	17.123	10.732
0.94	-11.621	16.852	17.209	11.086
0.96	-11.562	17.205	17.29	11.435
0.98	-11.499	17.55	17.364	11.777
1	**-11.434**	**17.887**	**17.434**	**12.113**
1.0286	-11.336	18.356	17.524	12.584
1.0572	-11.234	18.81	17.604	13.043
1.0858	-11.127	19.251	17.675	13.49
1.1144	-11.017	19.677	17.738	13.926
1.143	-10.904	20.091	17.792	14.351
1.1716	-10.788	20.491	17.84	14.766
1.2002	-10.67	20.88	17.88	15.17
1.2288	-10.55	21.256	17.914	15.564
1.2574	-10.428	21.621	17.942	15.948
1.286	-10.304	21.975	17.964	16.322
1.3146	-10.18	22.319	17.981	16.687
1.3432	-10.054	22.652	17.993	17.043
1.3718	-9.928	22.976	18.001	17.39
1.4004	-9.801	23.29	18.005	17.728
1.429	**-9.676**	**23.59**	**18.005**	**18.054**

Figure 5: Full table of 31 detailed lens shape point calculations. The bold highlighted rows correspond to the detailed calculations in Tables 2-7.

Table 2: Example Calculation (Lens Point 1)	
This example is for calculating the impedance the first point of the lens characteristic. Equal source voltages are used for the 230 kV (base) line with the sending-end voltage (E_S) leading the receiving-end voltage (E_R) by 120 degrees. See Figures 3 and 4.	
Eq. (6)	$E_S = \frac{V_{LL}\angle 120°}{\sqrt{3}}$

Table 2: Example Calculation (Lens Point 1)			
	$E_S = \frac{230{,}000\angle 120°\ V}{\sqrt{3}}$		
	$E_S = 132{,}791\angle 120°\ V$		
Eq. (7)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (8)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (9)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		
Total system current from sending-end source.			
Eq. (10)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \frac{132{,}791\angle 120°\ V - 132{,}791\angle 0°\ V}{(10 + j50\ )\Omega}$		
	$I_{sys} = 4{,}511\angle 71.3°\ A$		
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.			
Eq. (11)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$		

Table 2: Example Calculation (Lens Point 1)	
	$I_L = 4{,}511\angle 71.3° \; A \times \frac{(4 + j20) \times 10^{10} \; \Omega}{(4 + j20) \; \Omega + (4 + j20) \times 10^{10} \; \Omega}$
	$I_L = 4{,}511\angle 71.3° \; A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (12)	$V_S = E_S - (Z_S \times I_{sys})$
	$V_S = 132{,}791\angle 120° \; V - [(2 + j10) \; \Omega \times 4{,}511\angle 71.3° \; A]$
	$V_S = 95{,}757\angle 106.1° \; V$
The impedance seen by the relay on Z_L.	
Eq. (13)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{95{,}757\angle 106.1° \; V}{4{,}511\angle 71.3° \; A}$
	$Z_{L-Relay} = 17.434 + j12.113 \; \Omega$

Table 3: Example Calculation (Lens Point 2)			
This example is for calculating the impedance second point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the sending-end voltage (E_S) at 70% of the receiving-end voltage (E_R) and leading the receiving-end voltage by 120 degrees. See Figures 3 and 4.			
Eq. (14)	$E_S = \frac{V_{LL}\angle 120°}{\sqrt{3}} \times 70\%$		
	$E_S = \frac{230{,}000\angle 120° \; V}{\sqrt{3}} \times 0.70$		
	$E_S = 92{,}953.7\angle 120° \; V$		
Eq. (15)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \frac{230{,}000\angle 0° \; V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0° \; V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10 \; \Omega$	$Z_L = 4 + j20 \; \Omega$	$Z_R = 4 + j20 \; \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10} \; \Omega$		

Table 3: Example Calculation (Lens Point 2)	
Total impedance between the generators.	
Eq. (16)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$
	$Z_{total} = \frac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$
	$Z_{total} = 4 + j20\ \Omega$
Total system impedance.	
Eq. (17)	$Z_{sys} = Z_S + Z_{total} + Z_R$
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$
	$Z_{sys} = 10 + j50\ \Omega$
Total system current from sending-end source.	
Eq. (18)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$
	$I_{sys} = \frac{92{,}953.7\angle 120°\ V - 132{,}791\angle 0°\ V}{(10 + j50)\ \Omega}$
	$I_{sys} = 3{,}854\angle 77°\ A$
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (19)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 77°\ A \times \frac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$
	$I_L = 3{,}854\angle 77°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (20)	$V_S = E_S - \left(Z_S \times I_{sys}\right)$
	$V_S = 92{,}953\angle 120°\ V - [(2 + j10\ )\Omega \times 3{,}854\angle 77°\ A]$
	$V_S = 65{,}271\angle 99°\ V$
The impedance seen by the relay on Z_L.	
Eq. (21)	$Z_{L-Relay} = \frac{V_S}{I_L}$

Table 3: Example Calculation (Lens Point 2)	
	$Z_{L-Relay} = \frac{65{,}271\angle 99°\ V}{3{,}854\angle 77°\ A}$
	$Z_{L-Relay} = 15.676 + j6.41\ \Omega$

Table 4: Example Calculation (Lens Point 3)			
This example is for calculating the impedance third point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the receiving-end voltage (E_R) at 70% of the sending-end voltage (E_S) and the sending-end voltage leading the receiving-end voltage by 120 degrees. See Figures 3 and 4.			
Eq. (22)	$E_S = \frac{V_{LL}\angle 120°}{\sqrt{3}}$		
	$E_S = \frac{230{,}000\angle 120°\ V}{\sqrt{3}}$		
	$E_S = 132{,}791\angle 120°\ V$		
Eq. (23)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}} \times 70\%$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}} \times 0.70$		
	$E_R = 92{,}953.7\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (24)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (25)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		

Table 4: Example Calculation (Lens Point 3)	
Total system current from sending-end source.	
Eq. (26)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$
	$I_{sys} = \frac{132{,}791\angle 120°\ V - 92{,}953.7\angle 0°\ V}{(10 + j50)\ \Omega}$
	$I_{sys} = 3{,}854\angle 65.5°\ A$
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (27)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 65.5°\ A \times \frac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$
	$I_L = 3{,}854\angle 65.5°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (28)	$V_S = E_S - (Z_S \times I_L)$
	$V_S = 132{,}791\angle 120°\ V - [(2 + j10)\ \Omega \times 3{,}854\angle 65.5°\ A]$
	$V_S = 98{,}265\angle 110.6°\ V$
The impedance seen by the relay on Z_L.	
Eq. (29)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{98{,}265\angle 110.6°\ V}{3{,}854\angle 65.5°\ A}$
	$Z_{L-Relay} = 18.005 + j18.054\ \Omega$

Table 5: Example Calculation (Lens Point 4)	
This example is for calculating the impedance fourth point of the lens characteristic. Equal source voltages are used for the 230 kV (base) line with the sending-end voltage (E_S) leading the receiving-end voltage (E_R) by 240 degrees. See Figures 3 and 4.	
Eq. (30)	$E_S = \frac{V_{LL}\angle 240°}{\sqrt{3}}$
	$E_S = \frac{230{,}000\angle 240°\ V}{\sqrt{3}}$

Table 5: Example Calculation (Lens Point 4)			
	$E_S = 132{,}791\angle 240°\ V$		
Eq. (31)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (32)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (33)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		
Total system current from sending-end source.			
Eq. (34)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \frac{132{,}791\angle 240°\ V - 132{,}791\angle 0°\ V}{(10 + j50\ )\Omega}$		
	$I_{sys} = 4{,}511\angle 131.3°\ A$		
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.			
Eq. (35)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$		
	$I_L = 4{,}511\angle 131.1°\ A \times \frac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$		
	$I_L = 4{,}511\angle 131.1°\ A$		

Table 5: Example Calculation (Lens Point 4)			
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.			
Eq. (36)	$V_S = E_S - (Z_S \times I_L)$		
	$V_S = 132{,}791\angle 240° \, V - [(2 + j10\,)\,\Omega \times 4{,}511\angle 131.1° \, A]$		
	$V_S = 95{,}756\angle -106.1° \, V$		
The impedance seen by the relay on Z_L.			
Eq. (37)	$Z_{L-Relay} = \frac{V_S}{I_L}$		
	$Z_{L-Relay} = \frac{95{,}756\angle -106.1° \, V}{4{,}511\angle 131.1° \, A}$		
	$Z_{L-Relay} = -11.434 + j17.887\ \Omega$		

Table 6: Example Calculation (Lens Point 5)			
This example is for calculating the impedance fifth point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the sending-end voltage (E_S) at 70% of the receiving-end voltage (E_R) and leading the receiving-end voltage by 240 degrees. See Figures 3 and 4.			
Eq. (38)	$E_S = \frac{V_{LL}\angle 240°}{\sqrt{3}} \times 70\%$		
	$E_S = \frac{230{,}000\angle 240° \, V}{\sqrt{3}} \times 0.70$		
	$E_S = 92{,}953.7\angle 240° \, V$		
Eq. (39)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \frac{230{,}000\angle 0° \, V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0° \, V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (40)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		

Table 6: Example Calculation (Lens Point 5)	
	$Z_{total} = \frac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$
	$Z_{total} = 4 + j20\ \Omega$
Total system impedance.	
Eq. (41)	$Z_{sys} = Z_S + Z_{total} + Z_R$
	$Z_{sys} = (2 + j10\ \Omega) + (4 + j20\ \Omega) + (4 + j20\ \Omega)$
	$Z_{sys} = 10 + j50\ \Omega$
Total system current from sending-end source.	
Eq. (42)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$
	$I_{sys} = \frac{92{,}953.7\angle 240°\ V - 132{,}791\angle 0°\ V}{10 + j50\ \Omega}$
	$I_{sys} = 3{,}854\angle 125.5°\ A$
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (43)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 125.5°\ A \times \frac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$
	$I_L = 3{,}854\angle 125.5°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (44)	$V_S = E_S - (Z_S \times I_L)$
	$V_S = 92{,}953.7\angle 240°\ V - [(2 + j10\ )\ \Omega \times 3{,}854\angle 125.5°\ A]$
	$V_S = 65{,}270.5\angle -99.4°\ V$
The impedance seen by the relay on Z_L.	
Eq. (45)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{65{,}270.5\angle -99.4°\ V}{3{,}854\angle 125.5°\ A}$
	$Z_{L-Relay} = -12.005 + j11.946\ \Omega$

Table 7: Example Calculation (Lens Point 6)			
This example is for calculating the impedance sixth point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the receiving-end voltage (E_R) at 70% of the sending-end voltage (E_S) and the sending-end voltage leading the receiving-end voltage by 240 degrees. See Figures 3 and 4.			
Eq. (46)	$E_S = \frac{V_{LL}\angle 240°}{\sqrt{3}}$		
	$E_S = \frac{230{,}000\angle 240°\ V}{\sqrt{3}}$		
	$E_S = 132{,}791\angle 240°\ V$		
Eq. (47)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}} \times 70\%$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}} \times 0.70$		
	$E_R = 92{,}953.7\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (48)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (49)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		
Total system current from sending-end source.			
Eq. (50)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \frac{132{,}791\angle 240°\ V - 92{,}953.7\angle 0°\ V}{10 + j50\ \Omega}$		
	$I_{sys} = 3{,}854\angle 137.1°\ A$		

Table 7: Example Calculation (Lens Point 6)	
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (51)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 137.1° \, A \times \frac{(4 + j20) \times 10^{10} \, \Omega}{(4 + j20) \, \Omega + (4 + j20) \times 10^{10} \, \Omega}$
	$I_L = 3{,}854\angle 137.1° \, A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (52)	$V_S = E_S - (Z_S \times I_L)$
	$V_S = 132{,}791\angle 240° \, V - [(2 + j10 \,) \, \Omega \times 3{,}854\angle 137.1° \, A]$
	$V_S = 98{,}265\angle -110.6° \, V$
The impedance seen by the relay on Z_L.	
Eq. (53)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{98{,}265\angle -110.6° \, V}{3{,}854\angle 137.1° \, A}$
	$Z_{L-Relay} = -9.676 + j23.59 \, \Omega$

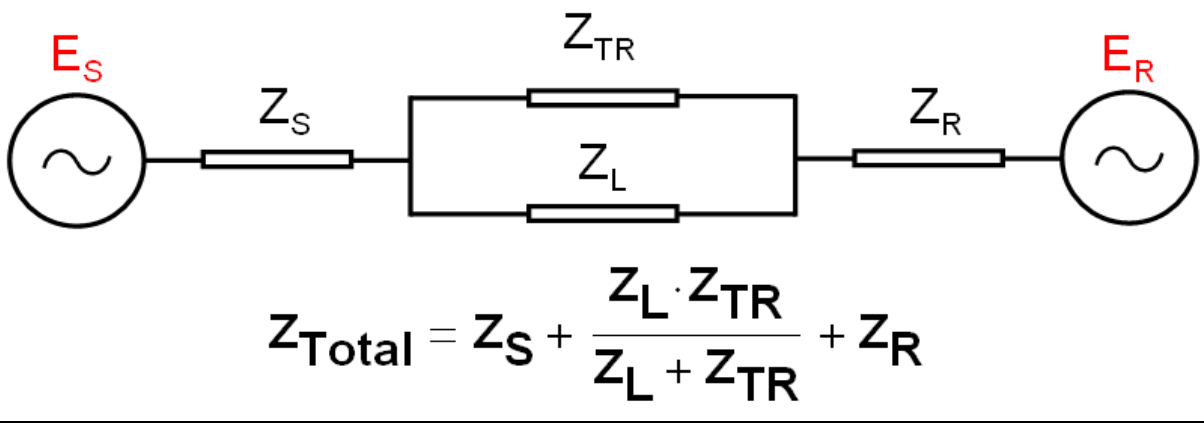

Figure 6: Reduced two bus system with sending-end source impedance Z_S, receiving-end source impedance Z_R, line impedance Z_L, and parallel transfer impedance Z_{TR}.

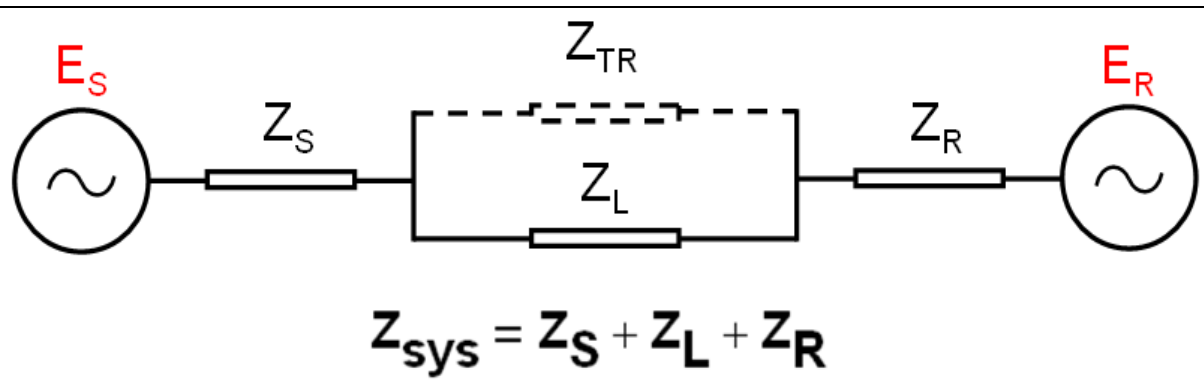

Figure 7: Reduced two bus system with sending-end source impedance Z_S, receiving-end source impedance Z_R, and line impedance Z_L with the parallel transfer impedance Z_{TR} removed.

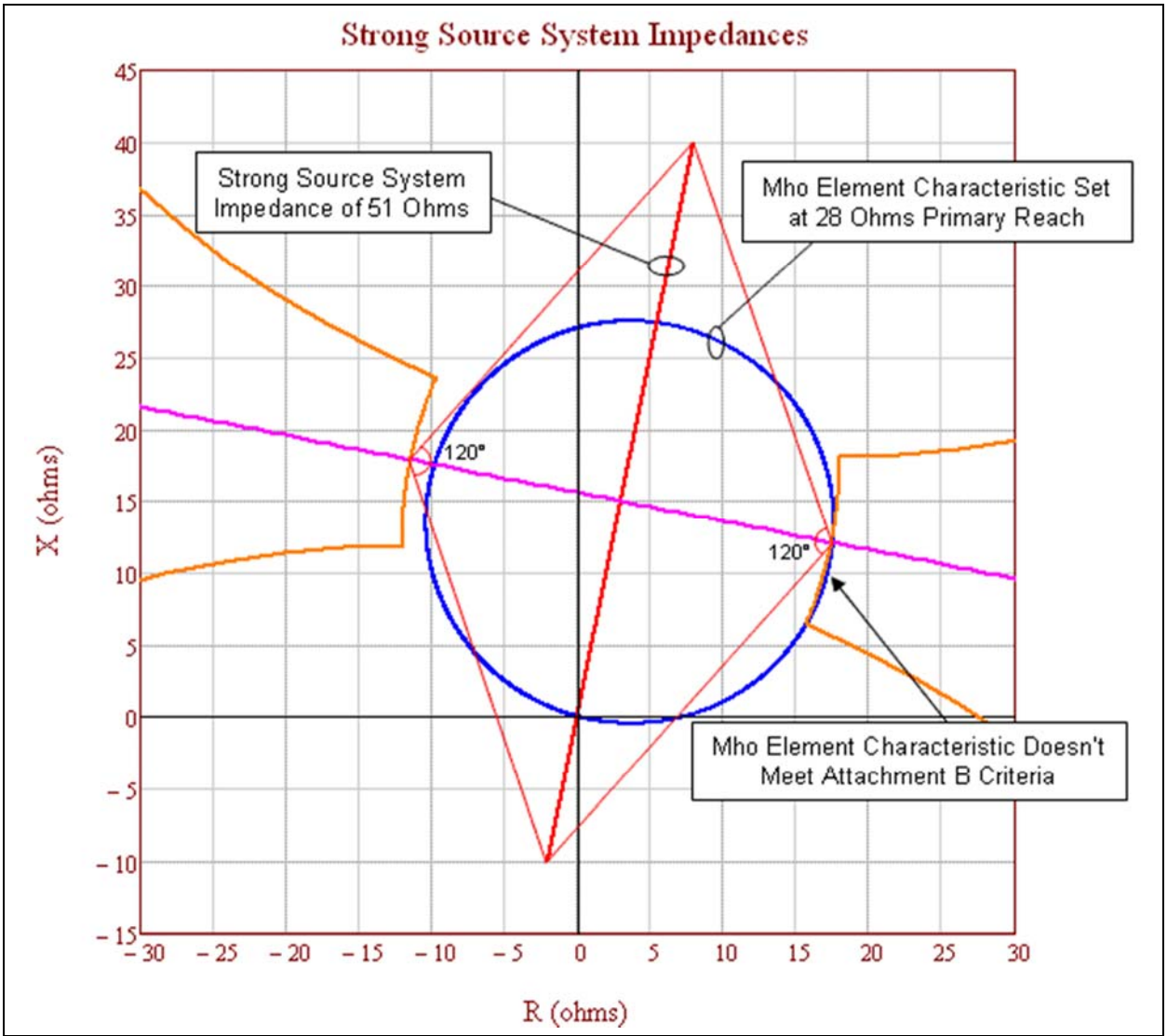

Figure 8: A strong-source system with a line impedance of Z_L = 20.4 ohms (i.e., the thicker red line). This mho element characteristic (i.e., the blue circle) does not meet the PRC-026-1 – Attachment B, Criterion A because it is not completely contained within the unstable power swing region (i.e., the orange characteristic).

Figure 8 above represents a heavily-loaded system with all generation in service and all transmission BES Elements in their normal operating state. The mho element characteristic (set at 137% of Z_L) extends into the unstable power swing region (i.e., the orange characteristic). Using the strongest source system is more conservative because it shrinks the unstable power swing region, bringing it closer to the mho element characteristic. This figure also graphically represents the effect of a system strengthening over time and this is the reason for re-evaluation if the relay has not been evaluated in the last five calendar years. Figure 9 below depicts a relay that meets the PRC-026-1 – Attachment B, Criterion A. Figure 8 depicts the same relay with the same setting five years later, where each source has strengthened by about 10% and now the same mho element characteristic does not meet Criterion A.

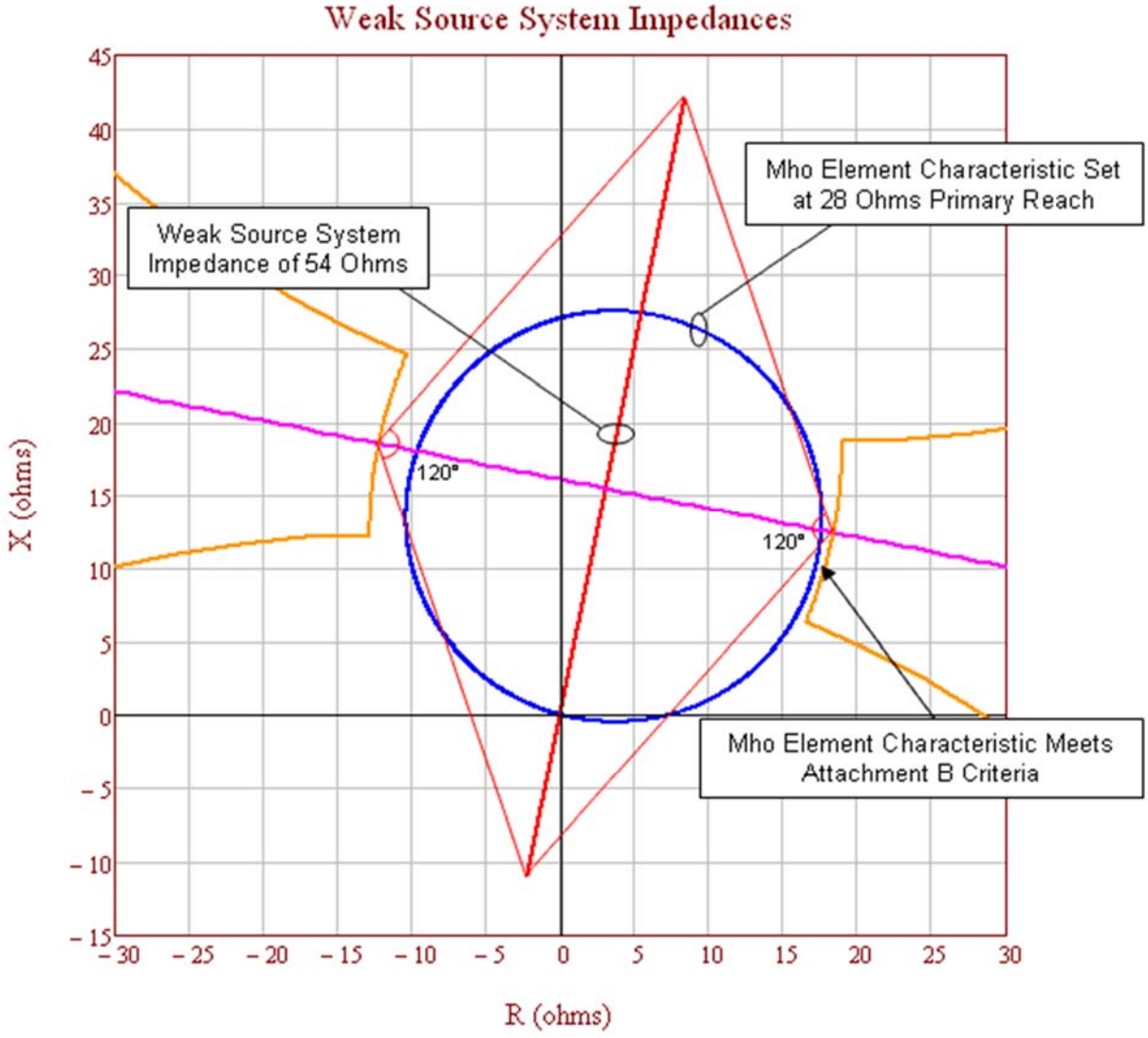

Figure 9: A weak-source system with a line impedance of Z_L = 20.4 ohms (i.e., the thicker red line). This mho element characteristic (i.e., the blue circle) meets the PRC-026-1 – Attachment B, Criterion A because it is completely contained within the unstable power swing region (i.e., the orange characteristic).

Figure 9 above represents a lightly-loaded system, using a minimum generation profile. The mho element characteristic (set at 137% of Z_L) does not extend into the unstable power swing region (i.e., the orange characteristic). Using a weaker source system expands the unstable power swing region away from the mho element characteristic.

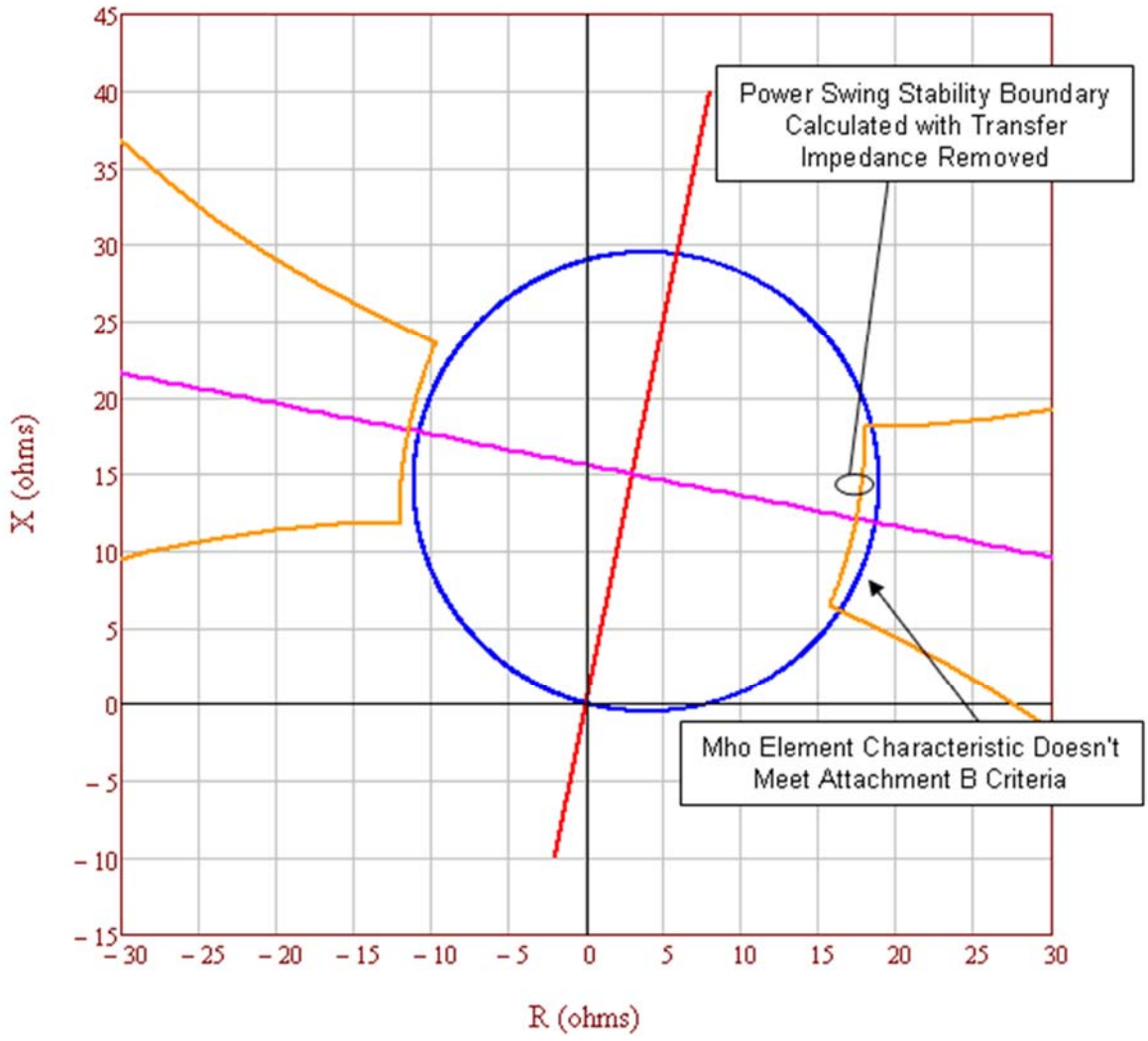

Figure 10: This is an example of an unstable power swing region (i.e., the orange characteristic) with the parallel transfer impedance removed. This relay mho element characteristic (i.e., the blue circle) does not meet PRC-026-1 – Attachment B, Criterion A because it is not completely contained within the unstable power swing region.

Table 8: Example Calculation (Parallel Transfer Impedance Removed)	
Calculations for the point at 120 degrees with equal source impedances. The total system current equals the line current. See Figure 10.	
Eq. (54)	$E_S = \frac{V_{LL}\angle 120°}{\sqrt{3}}$
	$E_S = \frac{230{,}000\angle 120°\ V}{\sqrt{3}}$
	$E_S = 132{,}791\angle 120°\ V$

Table 8: Example Calculation (Parallel Transfer Impedance Removed)			
Eq. (55)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Given impedance data.			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (56)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (57)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		
Total system current from sending-end source.			
Eq. (58)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \frac{132{,}791\angle 120°\ V - 132{,}791\angle 0°\ V}{10 + j50\ \Omega}$		
	$I_{sys} = 4{,}511\angle 71.3°\ A$		
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.			
Eq. (59)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$		
	$I_L = 4{,}511\angle 71.3°\ A \times \frac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$		
	$I_L = 4{,}511\angle 71.3°\ A$		

Table 8: Example Calculation (Parallel Transfer Impedance Removed)	
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (60)	$V_S = E_S - (Z_S \times I_{sys})$
	$V_S = 132{,}791\angle 120° \, V - [(2 + j10\ \Omega) \times 4{,}511\angle 71.3° \, A]$
	$V_S = 95{,}757\angle 106.1° \, V$
The impedance seen by the relay on Z_L.	
Eq. (61)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{95{,}757\angle 106.1° \, V}{4{,}511\angle 71.3° \, A}$
	$Z_{L-Relay} = 17.434 + j12.113\ \Omega$

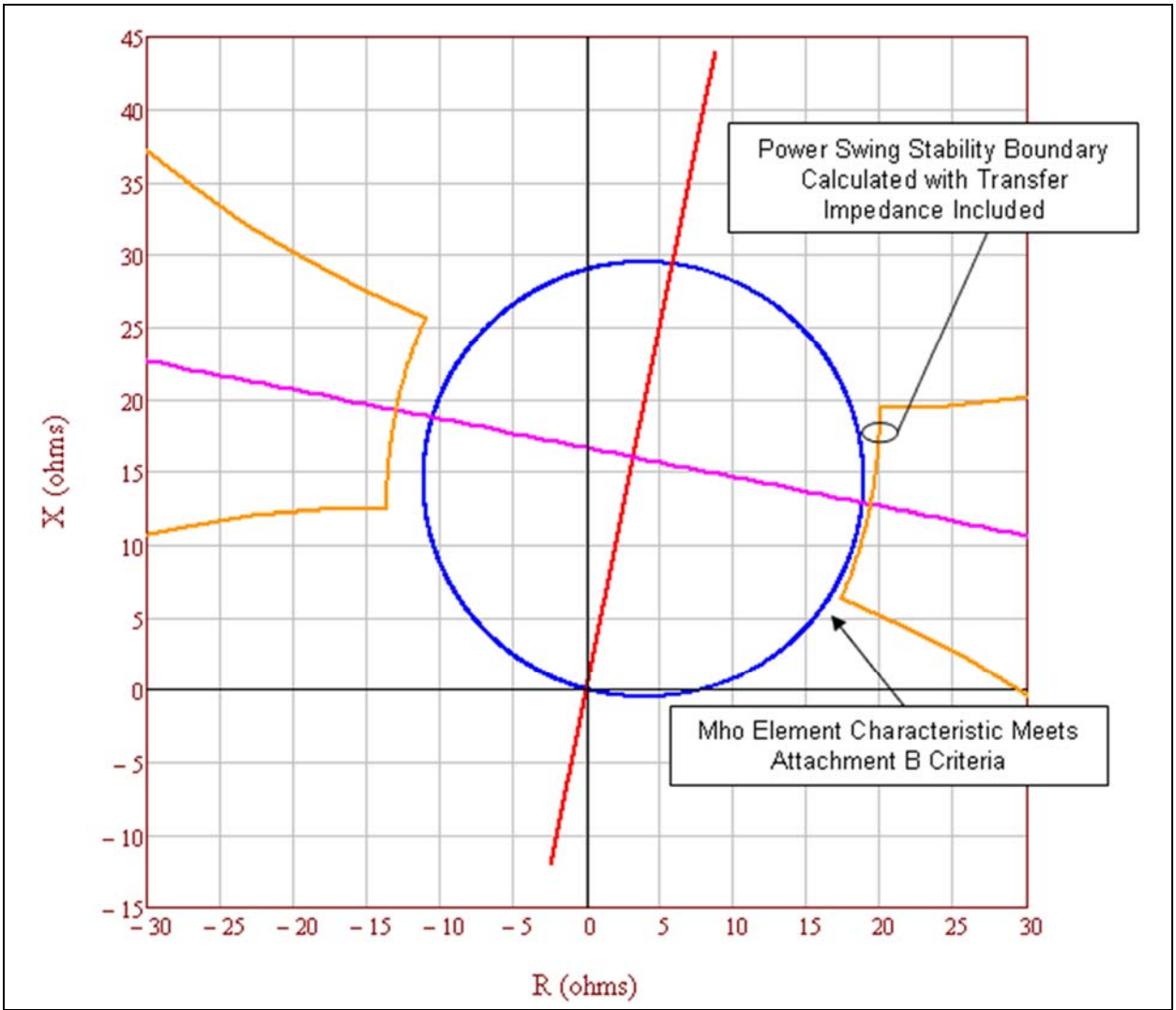

Figure 11: This is an example of an unstable power swing region (i.e., the orange characteristic) with the parallel transfer impedance included causing the mho element characteristic (i.e., the blue circle) to appear to meet the PRC-026-1 – Attachment B, Criterion A because it is completely contained within the unstable power swing region. Including the parallel transfer impedance in the calculation is not allowed by the PRC-026-1 – Attachment B, Criterion A.

In Figure 11 above, the parallel transfer impedance is 5 times the line impedance. The unstable power swing region has expanded out beyond the mho element characteristic due to the infeed effect from the parallel current through the parallel transfer impedance, thus allowing the mho element characteristic to appear to meet the PRC-026-1 – Attachment B, Criterion A. Including the parallel transfer impedance in the calculation is not allowed by the PRC-026-1 – Attachment B, Criterion A.

Table 9: Example Calculation (Parallel Transfer Impedance Included)			
Calculations for the point at 120 degrees with equal source impedances. The total system current does not equal the line current. See Figure 11.			
Eq. (62)	$E_S = \frac{V_{LL}\angle 120°}{\sqrt{3}}$		
	$E_S = \frac{230{,}000\angle 120°\ V}{\sqrt{3}}$		
	$E_S = 132{,}791\angle 120°\ V$		
Eq. (63)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Given impedance data.			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 5$		
	$Z_{TR} = (4 + j20)\ \Omega \times 5$		
	$Z_{TR} = 20 + j100\ \Omega$		
Total impedance between the generators.			
Eq. (64)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{(4 + j20)\ \Omega \times (20 + j100)\ \Omega}{(4 + j20)\ \Omega + (20 + j100)\ \Omega}$		
	$Z_{total} = 3.333 + j16.667\ \Omega$		
Total system impedance.			
Eq. (65)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (3.333 + j16.667)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 9.333 + j46.667\ \Omega$		
Total system current from sending-end source.			
Eq. (66)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \frac{132{,}791\angle 120°\ V - 132{,}791\angle 0°\ V}{9.333 + j46.667\ \Omega}$		

Table 9: Example Calculation (Parallel Transfer Impedance Included)	
	$I_{sys} = 4{,}833\angle 71.3° \; A$
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (67)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 4{,}833\angle 71.3° \; A \times \frac{(20 + j100)\;\Omega}{(4 + j20)\;\Omega + (20 + j100)\;\Omega}$
	$I_L = 4{,}027.4\angle 71.3° \; A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (68)	$V_S = E_S - (Z_S \times I_{sys})$
	$V_S = 132{,}791\angle 120° \; V - [(2 + j10\;\Omega) \times 4{,}833\angle 71.3° \; A]$
	$V_S = 93{,}417\angle 104.7° \; V$
The impedance seen by the relay on Z_L.	
Eq. (69)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{93{,}417\angle 104.7° \; V}{4{,}027\angle 71.3° \; A}$
	$Z_{L-Relay} = 19.366 + j12.767\;\Omega$

Table 10: Percent Increase of a Lens Due To Parallel Transfer Impedance.	
The following demonstrates the percent size increase of the lens characteristic for Z_{TR} in multiples of Z_L with the parallel transfer impedance included.	
Z_{TR} in multiples of Z_L	Percent increase of lens with equal EMF sources (Infinite source as reference)
Infinite	N/A
1000	0.05%
100	0.46%
10	4.63%
5	9.27%
2	23.26%
1	46.76%
0.5	94.14%
0.25	189.56%

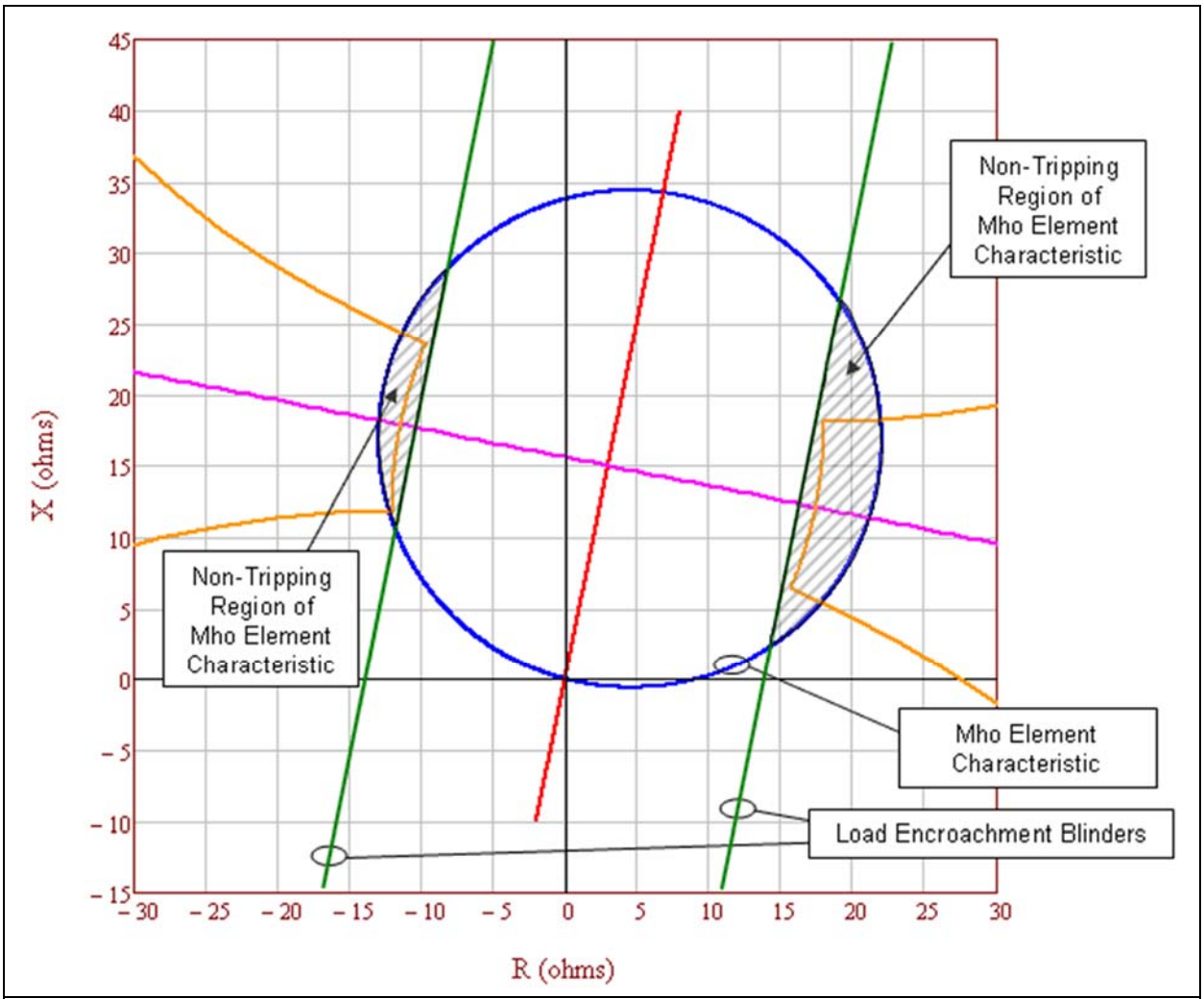

Figure 12: The tripping portion of the mho element characteristic (i.e., the blue circle) not blocked by load encroachment (i.e., the parallel green lines) is completely contained within the unstable power swing region (i.e., the orange characteristic). Therefore, the mho element characteristic meets the PRC-026-1 – Attachment B, Criterion A.

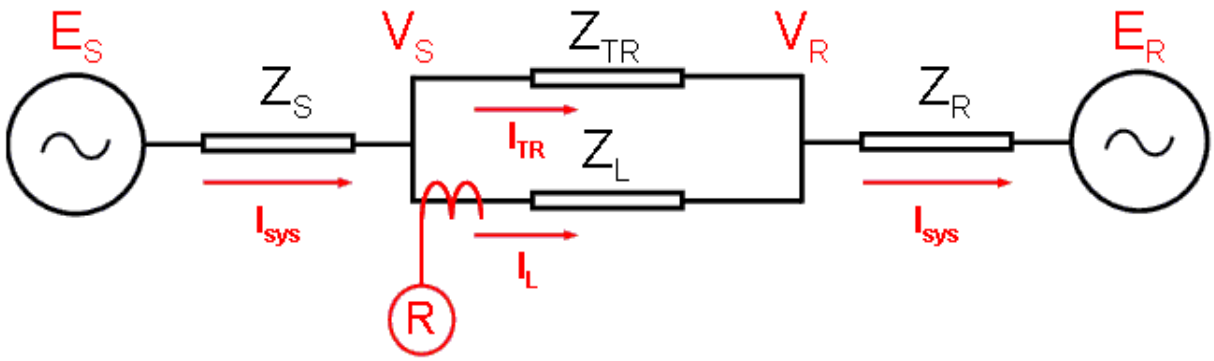

Figure 13: The infeed diagram shows the impedance in front of the relay R with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the forward direction becomes $Z_L + Z_R$.

Table 11: Calculations (System Apparent Impedance in the forward direction)				
The following equations are provided for calculating the apparent impedance back to the E_R source voltage as seen by relay R. Infeed equations from V_S to source E_R where $E_R = 0$. See Figure 13.				
Eq. (70)	$I_L = \frac{V_S - V_R}{Z_L}$			
Eq. (71)	$I_{sys} = \frac{V_R - E_R}{Z_R}$			
Eq. (72)	$I_{sys} = I_L + I_{TR}$			
Eq. (73)	$I_{sys} = \frac{V_R}{Z_R}$	Since $E_R = 0$	Rearranged:	$V_R = I_{sys} \times Z_R$
Eq. (74)	$I_L = \frac{V_S - I_{sys} \times Z_R}{Z_L}$			
Eq. (75)	$I_L = \frac{V_S - [(I_L + I_{TR}) \times Z_R]}{Z_L}$			
Eq. (76)	$V_S = (I_L \times Z_L) + (I_L \times Z_R) + (I_{TR} \times Z_R)$			
Eq. (77)	$Z_{Relay} = \frac{V_S}{I_L} = Z_L + Z_R + \frac{I_{TR} \times Z_R}{I_L} = Z_L + Z_R \times \left(1 + \frac{I_{TR}}{I_L}\right)$			
Eq. (78)	$I_{TR} = I_{sys} \times \frac{Z_L}{Z_L + Z_{TR}}$			
Eq. (79)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$			

Table 11: Calculations (System Apparent Impedance in the forward direction)	
Eq. (80)	$\frac{I_{TR}}{I_L} = \frac{Z_L}{Z_{TR}}$
The infeed equations shows the impedance in front of the relay R (Figure 13) with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the forward direction becomes $Z_L + Z_R$.	
Eq. (81)	$Z_{Relay} = Z_L + Z_R \times \left(1 + \frac{Z_L}{Z_{TR}}\right)$

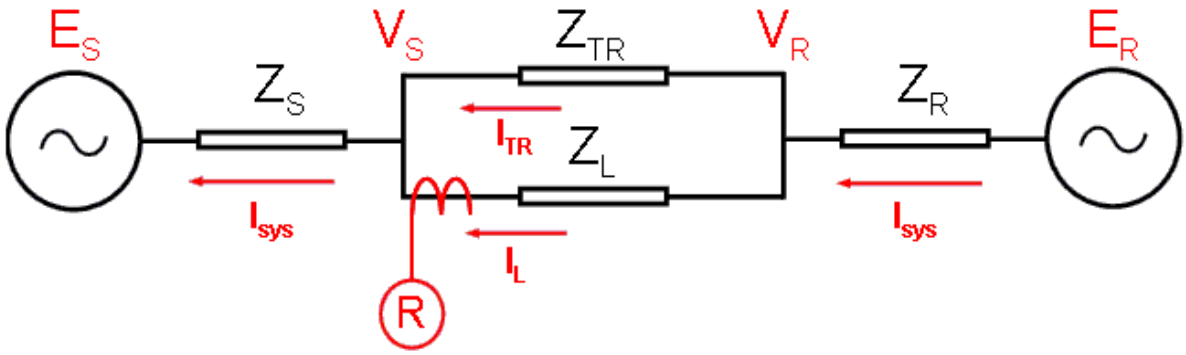

Figure 14: The infeed diagram shows the impedance behind relay R with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the reverse direction becomes Z_S.

Table 12: Calculations (System Apparent Impedance in the Reverse Direction)				
The following equations are provided for calculating the apparent impedance back to the E_S source voltage as seen by relay R. Infeed equations from V_R back to source E_S where $E_S = 0$. See Figure 14.				
Eq. (82)	$I_L = \frac{V_R - V_S}{Z_L}$			
Eq. (83)	$I_{sys} = \frac{V_S - E_S}{Z_S}$			
Eq. (84)	$I_{sys} = I_L + I_{TR}$			
Eq. (85)	$I_{sys} = \frac{V_S}{Z_S}$	Since $E_s = 0$	Rearranged:	$V_S = I_{sys} \times Z_S$
Eq. (86)	$I_L = \frac{V_R - I_{sys} \times Z_S}{Z_L}$			

Table 12: Calculations (System Apparent Impedance in the Reverse Direction)		
Eq. (87)	$I_L = \frac{V_R - [(I_L + I_{TR}) \times Z_S]}{Z_L}$	
Eq. (88)	$V_R = (I_L \times Z_L) + (I_L \times Z_S) + (I_{TR} \times Z_{RS})$	
Eq. (89)	$Z_{Relay} = \frac{V_R}{I_L} = Z_L + Z_S + \frac{I_{TR} \times Z_S}{I_L} = Z_L + Z_S \times \left(1 + \frac{I_{TR}}{I_L}\right)$	
Eq. (90)	$I_{TR} = I_{sys} \times \frac{Z_L}{Z_L + Z_{TR}}$	
Eq. (91)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$	
Eq. (92)	$\frac{I_{TR}}{I_L} = \frac{Z_L}{Z_{TR}}$	
The infeed equations shows the impedance behind relay R (Figure 14) with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the reverse direction becomes Z_S.		
Eq. (93)	$Z_{Relay} = Z_L + Z_S \times \left(1 + \frac{Z_L}{Z_{TR}}\right)$	As seen by relay R at the receiving-end of the line.
Eq. (94)	$Z_{Relay} = Z_S \times \left(1 + \frac{Z_L}{Z_{TR}}\right)$	Subtract Z_L for relay R impedance as seen at sending-end of the line.

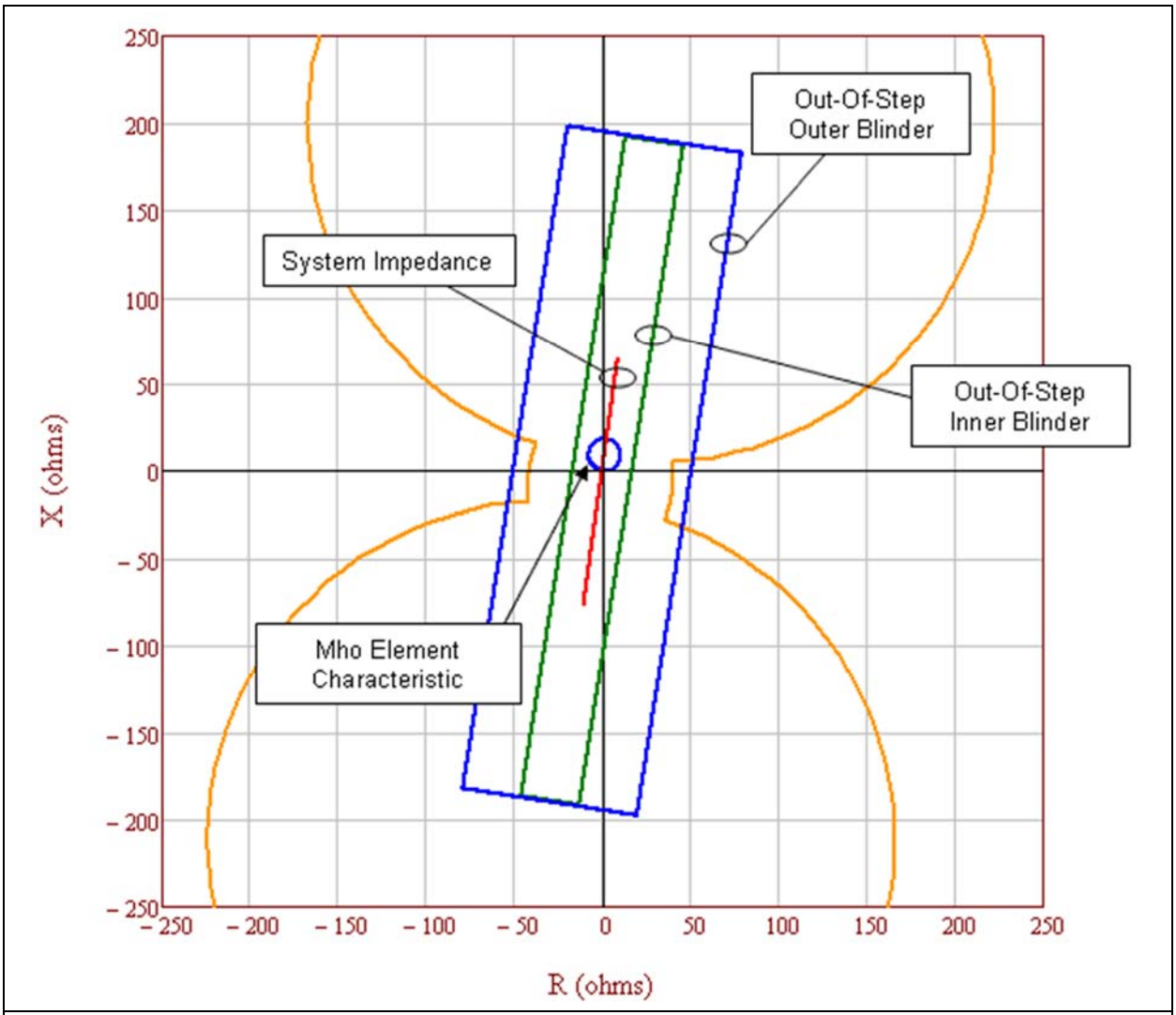

Figure 15: Out-of-step trip (OST) inner blinder (i.e., the parallel green lines) meets the PRC-026-1 – Attachment B, Criterion A because the inner OST blinder initiates tripping either On-The-Way-In or On-The-Way-Out. Since the inner blinder is completely contained within the unstable power swing region (i.e., the orange characteristic), it meets the PRC-026-1 – Attachment B, Criterion A.

Table 13: Example Calculation (Voltage Ratios)			
These calculations are based on the loss-of-synchronism characteristics for the cases of N < 1 and N > 1 as found in the *Application of Out-of-Step Blocking and Tripping Relays*, GER-3180, p. 12, Figure 3.[18] The GE illustration shows the formulae used to calculate the radius and center of the circles that make up the ends of the portion of the lens.			
Voltage ratio equations, source impedance equation with infeed formulae applied, and circle equations.			
Given:	$E_S = 0.7$	$E_R = 1.0$	
Eq. (95)	$N = \frac{\lvert E_S \rvert}{\lvert E_R \rvert} = \frac{0.7}{1.0} = 0.7$		
The total system impedance as seen by the relay with infeed formulae applied.			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
	$Z_{TR} = (4 + j20) \times 10^{10}\ \Omega$		
Eq. (96)	$Z_{sys} = Z_S \times \left(1 + \frac{Z_L}{Z_{TR}}\right) + \left[Z_L + Z_R \times \left(1 + \frac{Z_L}{Z_{TR}}\right)\right]$		
	$Z_{sys} = 10 + j50\ \Omega$		
The calculated coordinates of the lower loss-of-synchronism circle center.			
Eq. (97)	$Z_{C1} = -\left[Z_S \times \left(1 + \frac{Z_L}{Z_{TR}}\right)\right] - \left[\frac{N^2 \times Z_{sys}}{1 - N^2}\right]$		
	$Z_{C1} = -\left[(2 + j10)\ \Omega \times \left(1 + \frac{(4 + j20)\ \Omega}{(4 + j20) \times 10^{10}\ \Omega}\right)\right] - \left[\frac{0.7^2 \times (10 + j50)\ \Omega}{1 - 0.7^2}\right]$		
	$Z_{C1} = -11.608 - j58.039\ \Omega$		
The calculated radius of the lower loss-of-synchronism circle.			
Eq. (98)	$r_a = \left\lvert \frac{N \times Z_{sys}}{1 - N^2} \right\rvert$		
	$r_a = \left\lvert \frac{0.7 \times (10 + j50)\ \Omega}{1 - 0.7^2} \right\rvert$		
	$r_a = 69.987\ \Omega$		
The calculated coordinates of the upper loss-of-synchronism circle center.			
Given:	$E_S = 1.0$	$E_R = 0.7$	

[18] http://store.gedigitalenergy.com/faq/Documents/Alps/GER-3180.pdf

Table 13: Example Calculation (Voltage Ratios)	
Eq. (99)	$N = \frac{\lvert E_S \rvert}{\lvert E_R \rvert} = \frac{1.0}{0.7} = 1.43$
Eq. (100)	$Z_{C2} = Z_L + \left[Z_R \times \left(1 + \frac{Z_L}{Z_{TR}} \right) \right] + \left[\frac{Z_{sys}}{N^2 - 1} \right]$
	$Z_{C2} = 4 + j20\ \Omega + \left[(4 + j20)\ \Omega \times \left(1 + \frac{(4 + j20)\ \Omega}{(4 + j20) \times 10^{10}\ \Omega} \right) \right] + \left[\frac{(10 + j50)\ \Omega}{1.43^2 - 1} \right]$
	$Z_{C2} = 17.608 + j88.039\ \Omega$
The calculated radius of the upper loss-of-synchronism circle.	
Eq. (101)	$r_b = \left\lvert \frac{N \times Z_{sys}}{N^2 - 1} \right\rvert$
	$r_b = \left\lvert \frac{1.43 \times (10 + j50)\ \Omega}{1.43^2 - 1} \right\rvert$
	$r_b = 69.987\ \Omega$

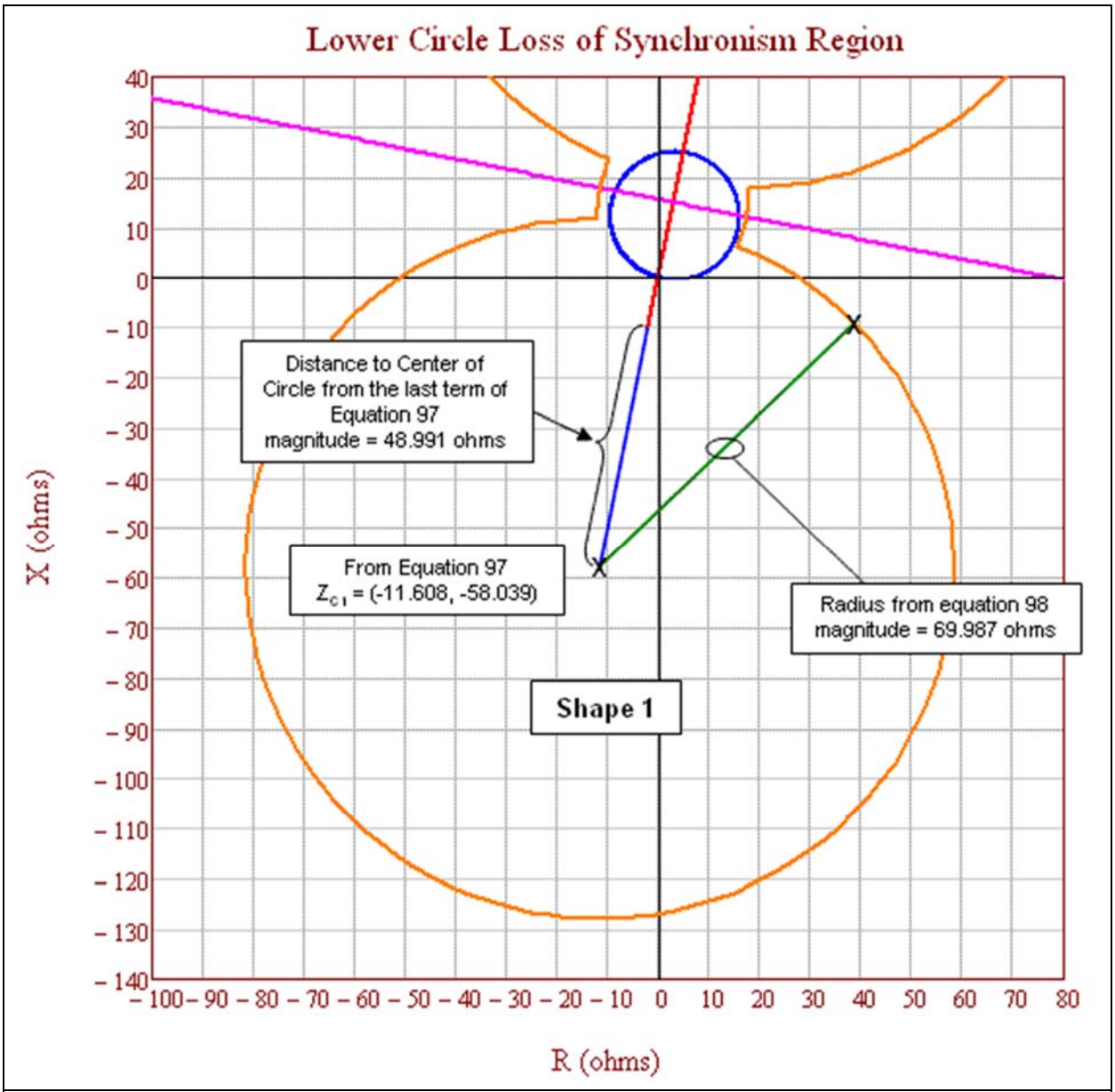

Figure 15a: Lower circle loss-of-synchronism region showing the coordinates of the circle center and the circle radius.

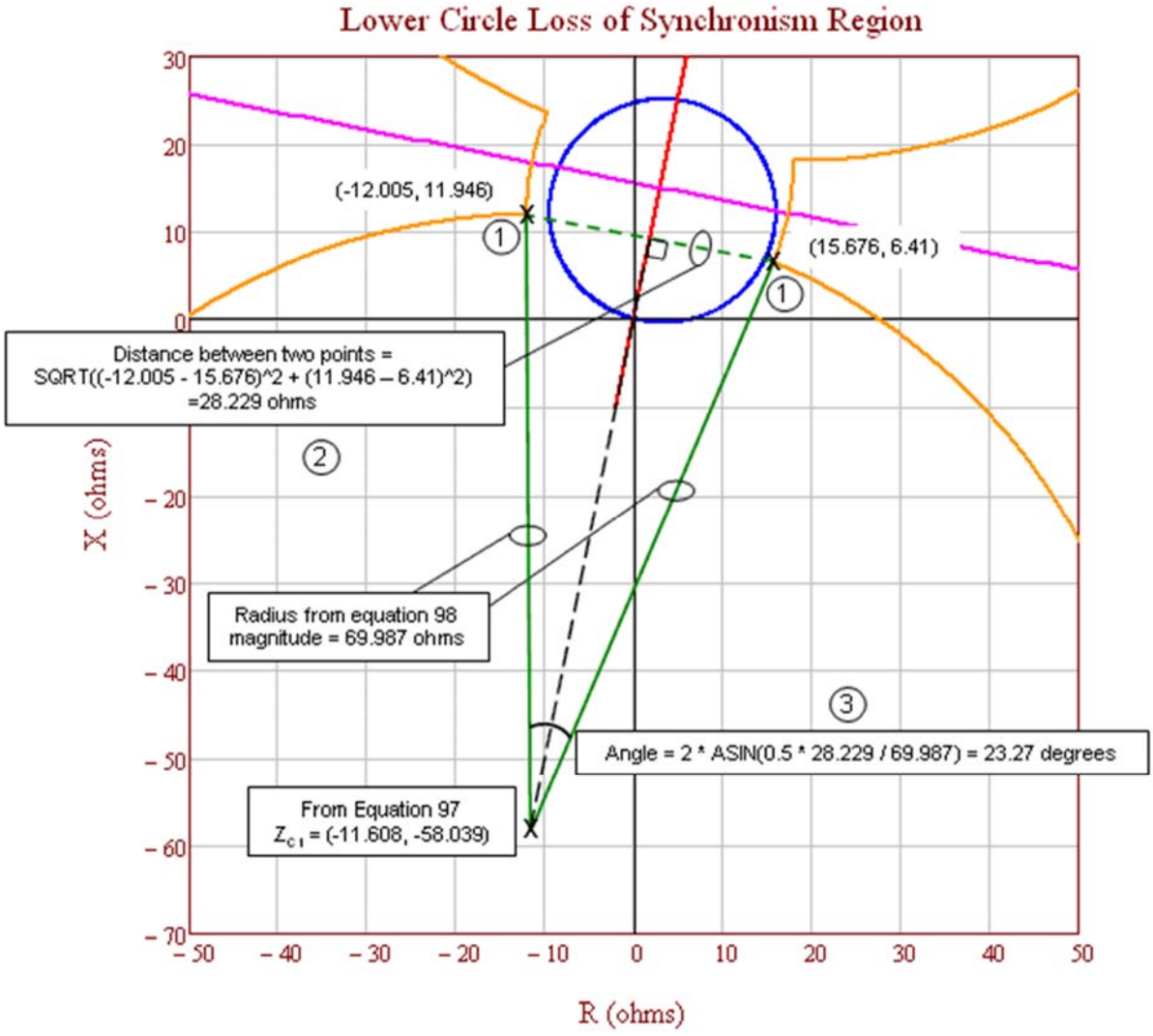

Figure 15b: Lower circle loss-of-synchronism region showing the first three steps to calculate the coordinates of the points on the circle. 1) Identify the lower circle loss-of-synchronism points that intersect the lens shape where the sending-end to receiving-end voltage ratio is 0.7 (see lens shape calculations in Tables 2-7). 2) Calculate the distance between the two lower circle loss-of-synchronism points identified in Step 1. 3) Calculate the angle of arc that connects the two lower circle loss-of-synchronism points identified in Step 1.

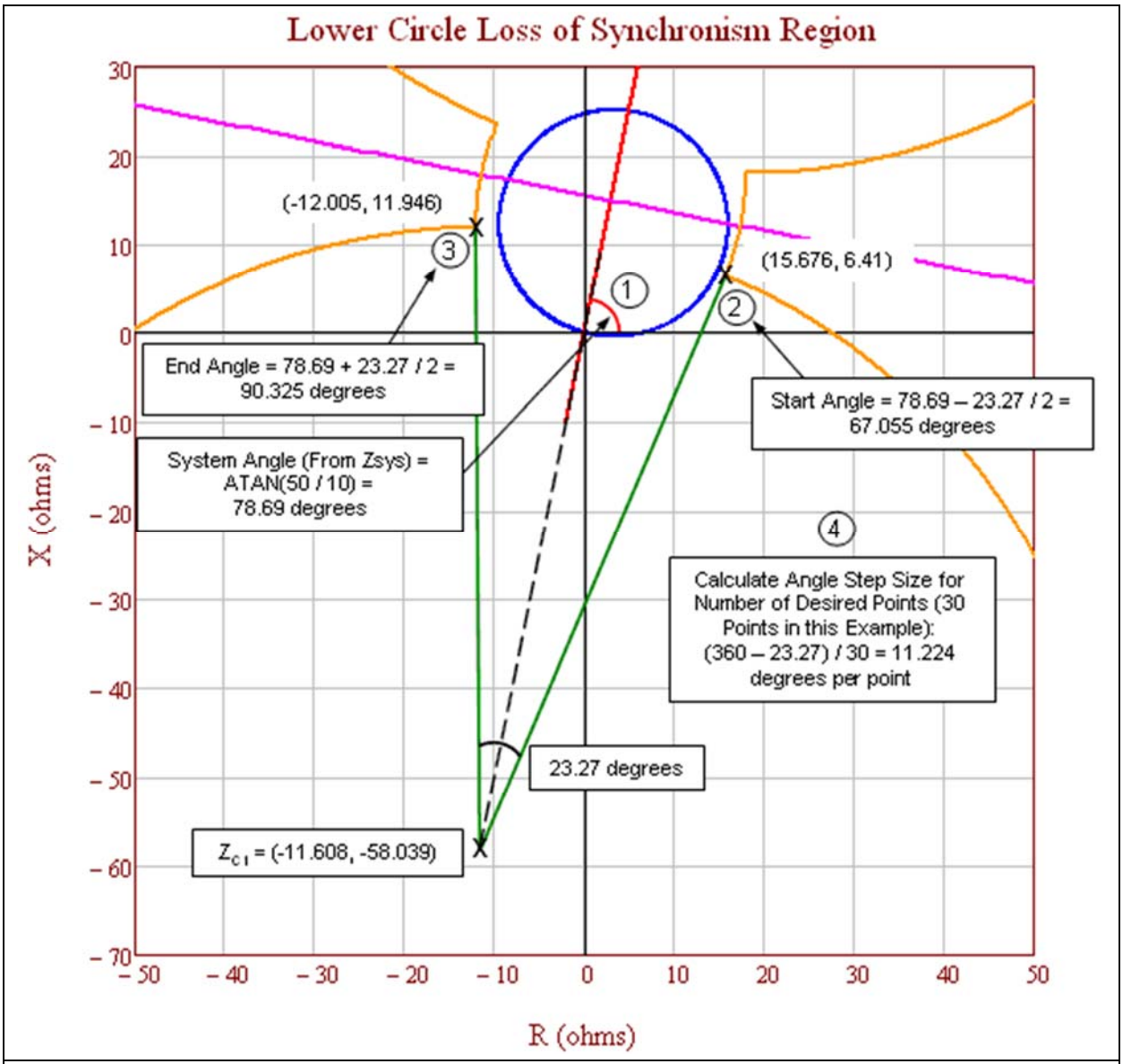

Figure 15c: Lower circle loss-of-synchronism region showing the steps to calculate the start angle, end angle, and the angle step size for the desired number of calculated points. 1) Calculate the system angle. 2) Calculate the start angle. 3) Calculate the end angle. 4) Calculate the angle step size for the desired number of points.

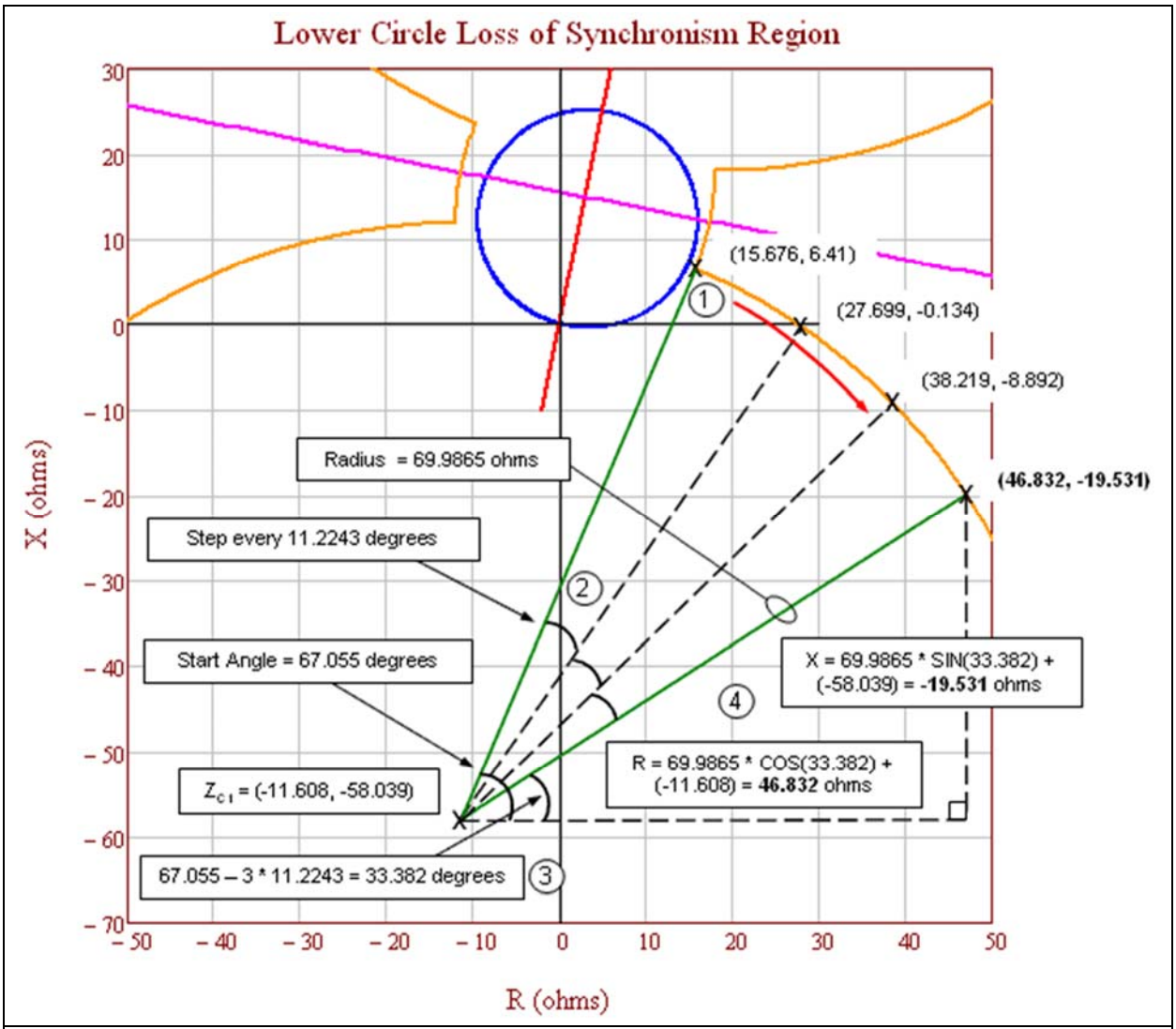

Figure 15d: Lower circle loss-of-synchronism region showing the final steps to calculate the coordinates of the points on the circle. 1) Start at the intersection with the lens shape and proceed in a clockwise direction. 2) Advance the step angle for each point. 3) Calculate the new angle after step advancement. 4) Calculate the R–X coordinates.

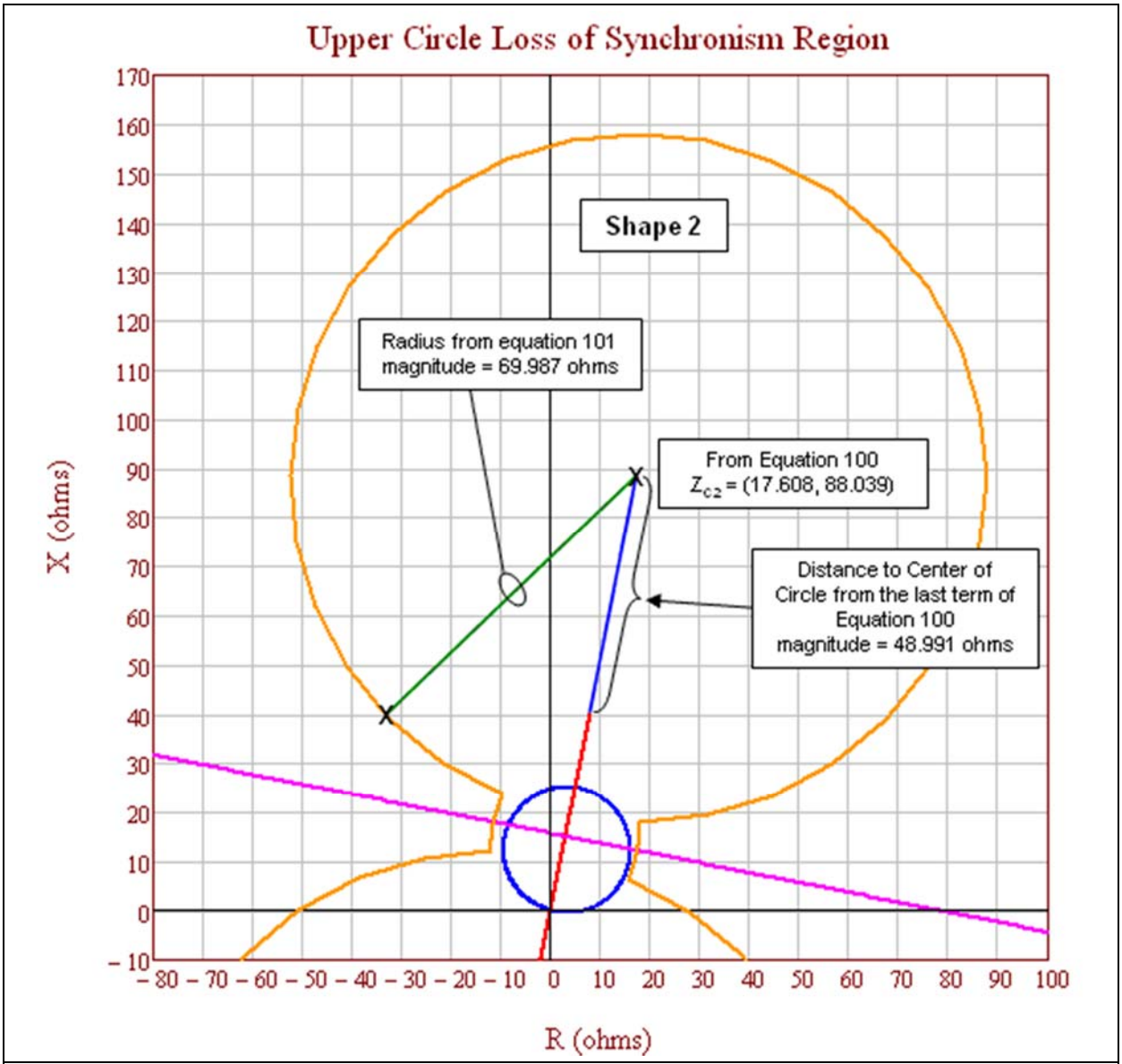

Figure 15e: Upper circle loss-of-synchronism region showing the coordinates of the circle center and the circle radius.

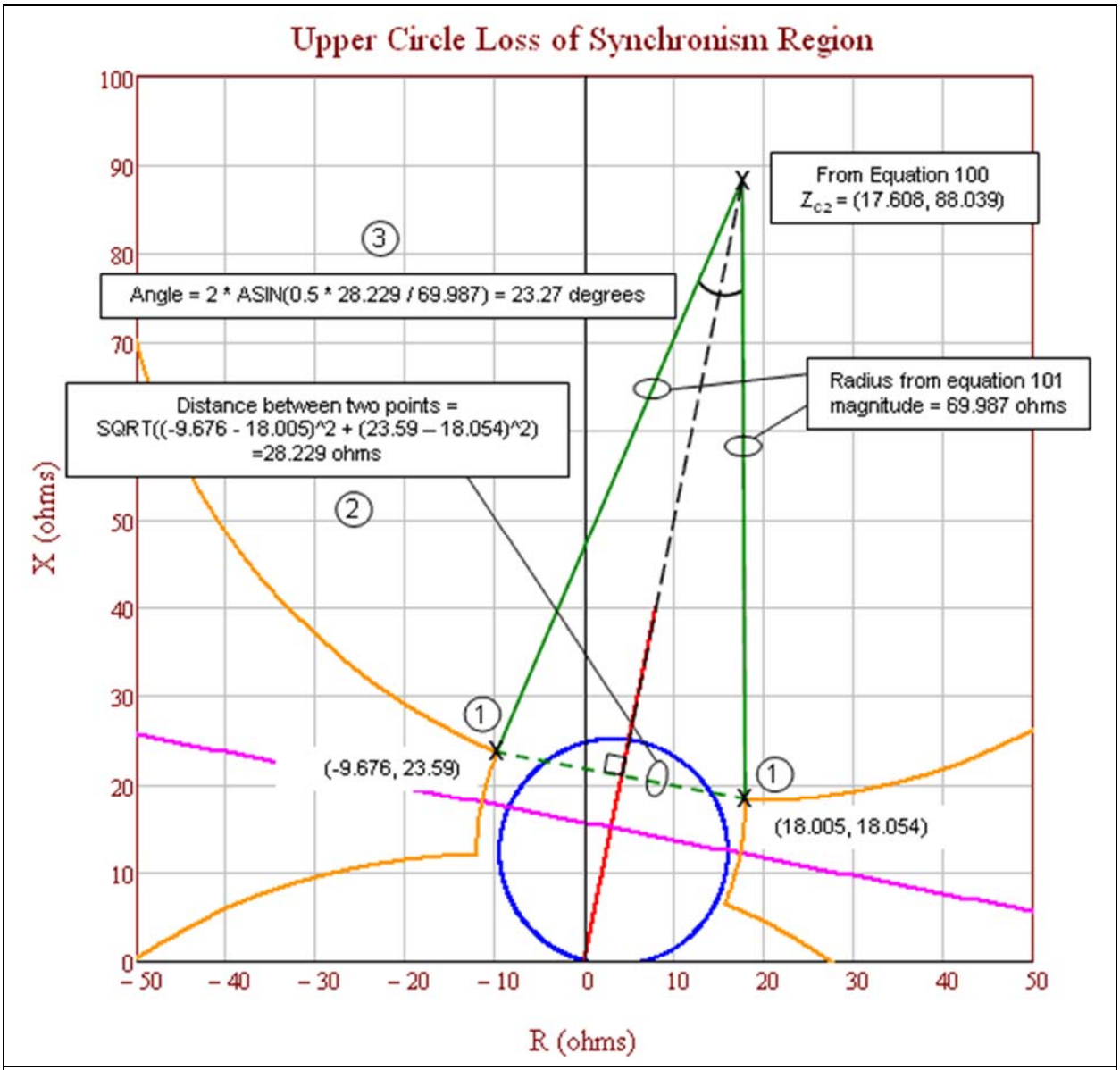

Figure 15f: Upper circle loss-of-synchronism region showing the first three steps to calculate the coordinates of the points on the circle. 1) Identify the upper circle points that intersect the lens shape where the sending-end to receiving-end voltage ratio is 1.43 (see lens shape calculations in Tables 2-7). 2) Calculate the distance between the two upper circle points identified in Step 1. 3) Calculate the angle of arc that connects the two upper circle points identified in Step 1.

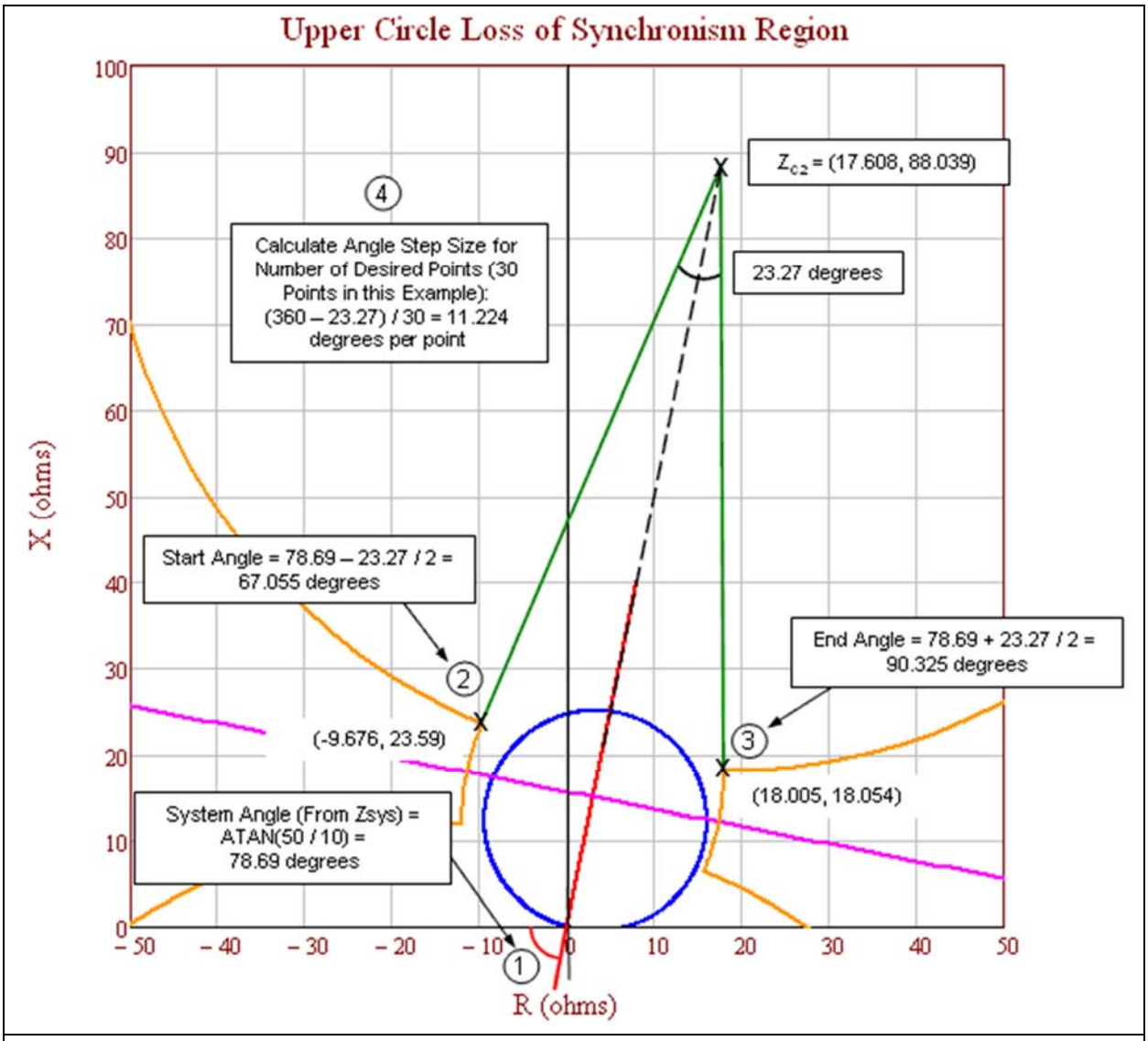

Figure 15g: Upper circle loss-of-synchronism region showing the steps to calculate the start angle, end angle, and the angle step size for the desired number of calculated points. 1) Calculate the system angle. 2) Calculate the start angle. 3) Calculate the end angle. 4) Calculate the angle step size for the desired number of points.

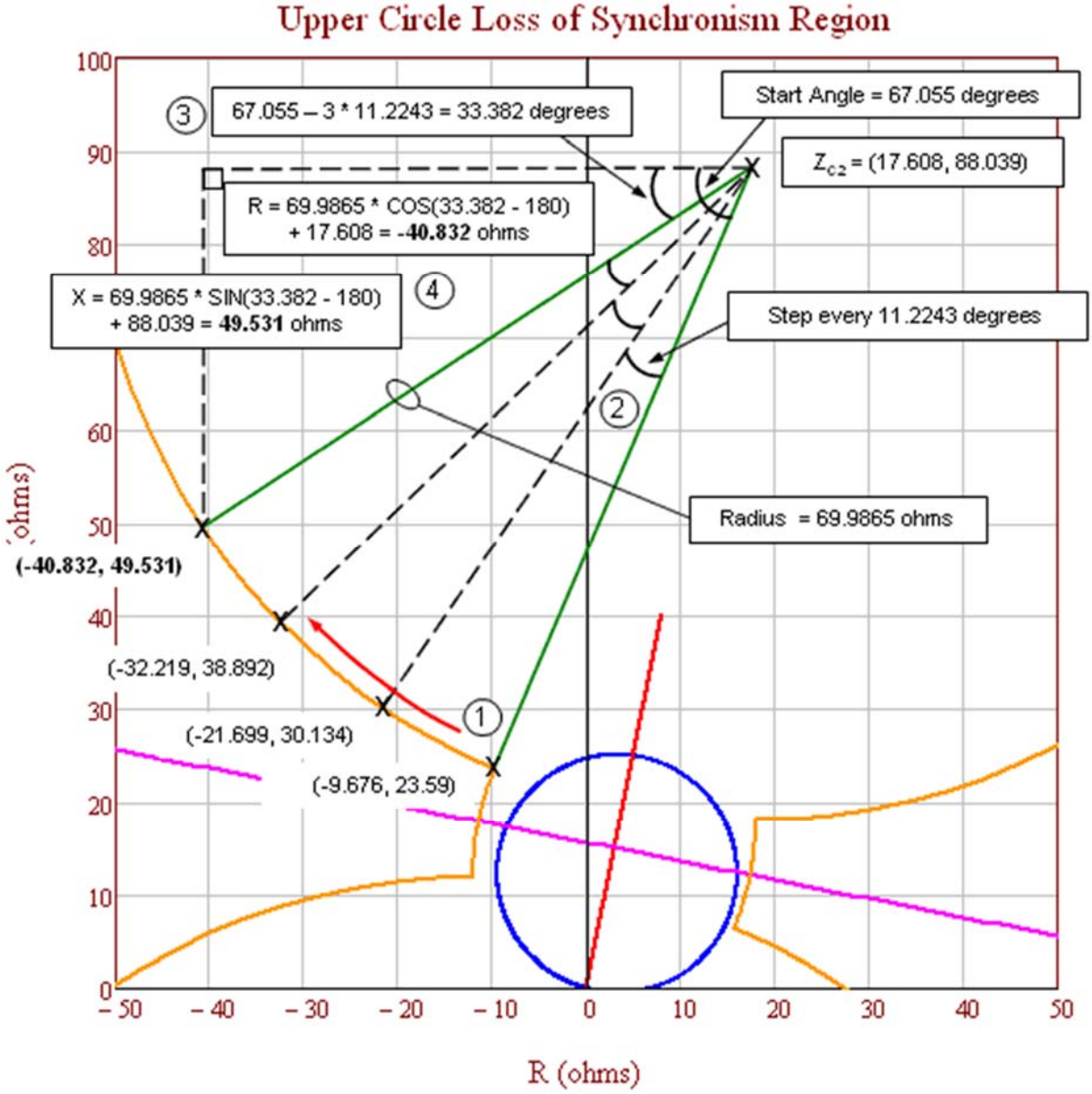

Figure 15h: Upper circle loss-of-synchronism region showing the final steps to calculate the coordinates of the points on the circle. 1) Start at the intersection with the lens shape and proceed in a clockwise direction. 2) Advance the step angle for each point. 3) Calculate the new angle after step advancement. 4) Calculate the R-X coordinates.

Lower Loss of Synchronism Circle Coordinates		
Angle (degrees)	R	+ jX
67.055	15.676	6.41
55.831	27.699	-0.134
44.606	38.219	-8.892
33.382	**46.832**	**-19.531**
22.158	53.21	-31.643
10.933	57.108	-44.765
359.709	58.378	-58.395
348.485	56.97	-72.011
337.26	52.939	-85.092
326.036	46.438	-97.139
314.812	37.717	-107.69
303.587	27.109	-116.341
292.363	15.02	-122.762
281.139	1.913	-126.707
269.914	-11.712	-128.026
258.69	-25.333	-126.667
247.466	-38.429	-122.682
236.241	-50.499	-116.225
225.017	-61.081	-107.542
213.793	-69.771	-96.965
202.568	-76.235	-84.899
191.344	-80.227	-71.806
180.12	-81.594	-58.185
168.895	-80.284	-44.56
157.671	-76.347	-31.45
146.447	-69.933	-19.357
135.222	-61.288	-8.744
123.998	-50.742	-0.016
112.774	-38.699	6.491
101.549	-25.62	10.53
90.325	-12.005	11.946

Upper Loss of Synchronism Circle Coordinates		
Angle (degrees)	R	+ jX
67.055	-9.676	23.59
55.831	-21.699	30.134
44.606	-32.219	38.892
33.382	**-40.832**	**49.531**
22.158	-47.21	61.643
10.933	-51.108	74.765
359.709	-52.378	88.395
348.485	-50.97	102.011
337.26	-46.939	115.092
326.036	-40.438	127.139
314.812	-31.717	137.69
303.587	-21.109	146.341
292.363	-9.02	152.762
281.139	4.087	156.707
269.914	17.712	158.026
258.69	31.333	156.667
247.466	44.429	152.682
236.241	56.499	146.225
225.017	67.081	137.542
213.793	75.771	126.965
202.568	82.235	114.899
191.344	86.227	101.806
180.12	87.594	88.185
168.895	86.284	74.56
157.671	82.347	61.45
146.447	75.933	49.357
135.222	67.288	38.744
123.998	56.742	30.016
112.774	44.699	23.509
101.549	31.62	19.47
90.325	18.005	18.054

Figure 15i: Full tables of calculated lower and upper loss-of-synchronism circle coordinates. The highlighted row is the detailed calculated points in Figures 15d and 15h.

Application Specific to Criterion B

The PRC-026-1 – Attachment B, Criterion B evaluates overcurrent elements used for tripping. The same criteria as PRC-026-1 – Attachment B, Criterion A is used except for an additional criterion (No. 4) that calculates a current magnitude based upon generator internal voltage of 1.05 per unit. A value of 1.05 per unit generator voltage is used to establish a minimum pickup current value for overcurrent relays that have a time delay less than 15 cycles. The sending-end and receiving-end voltages are established at 1.05 per unit at 120 degree system separation angle. The 1.05 per unit is the typical upper end of the operating voltage, which is also consistent with the maximum power

transfer calculation using actual system source impedances in the PRC-023 NERC Reliability Standard. The formulas used to calculate the current are in Table 14 below.

Table 14: Example Calculation (Overcurrent)

This example is for a 230 kV line terminal with a directional instantaneous phase overcurrent element set to 50 amps secondary times a CT ratio of 160:1 that equals 8,000 amps, primary. The following calculation is where V_S equals the base line-to-ground sending-end generator source voltage times 1.05 at an angle of 120 degrees, V_R equals the base line-to-ground receiving-end generator internal voltage times 1.05 at an angle of 0 degrees, and Z_{sys} equals the sum of the sending-end source, line, and receiving-end source impedances in ohms.

Here, the instantaneous phase setting of 8,000 amps is greater than the calculated system current of 5,716 amps; therefore, it meets PRC-026-1 – Attachment B, Criterion B.

Eq. (102)	$V_S = \frac{V_{LL}\angle 120°}{\sqrt{3}} \times 1.05$		
	$V_S = \frac{230{,}000\angle 120°\ V}{\sqrt{3}} \times 1.05$		
	$V_S = 139{,}430\angle 120°\ V$		
Receiving-end generator terminal voltage.			
Eq. (103)	$V_R = \frac{V_{LL}\angle 0°}{\sqrt{3}} \times 1.05$		
	$V_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}} \times 1.05$		
	$V_R = 139{,}430\angle 0°\ V$		
The total impedance of the system (Z_{sys}) equals the sum of the sending-end source impedance (Z_S), the impedance of the line (Z_L), and receiving-end impedance (Z_R) in ohms.			
Given:	$Z_S = 3 + j26\ \Omega$	$Z_L = 1.3 + j8.7\ \Omega$	$Z_R = 0.3 + j7.3\ \Omega$
Eq. (104)	$Z_{sys} = Z_S + Z_L + Z_R$		
	$Z_{sys} = (3 + j26)\ \Omega + (1.3 + j8.7)\ \Omega + (0.3 + j7.3)\ \Omega$		
	$Z_{sys} = 4.6 + j42\ \Omega$		
Total system current.			
Eq. (105)	$I_{sys} = \frac{(V_S - V_R)}{Z_{sys}}$		
	$I_{sys} = \frac{(139{,}430\angle 120°\ V - 139{,}430\angle 0°\ V)}{(4.6 + j42)\ \Omega}$		
	$I_{sys} = 5{,}715.82\angle 66.25°\ A$		

Application Specific to Three-Terminal Lines

If a three-terminal line is identified as an Element that is susceptible to a power swing based on Requirement R1, the load-responsive protective relays at each end of the three-terminal line must be evaluated.

As shown in Figure 15j, the source impedances at each end of the line can be obtained from the similar short circuit calculation as for the two-terminal line (assuming the parallel transfer impedances are ignored).

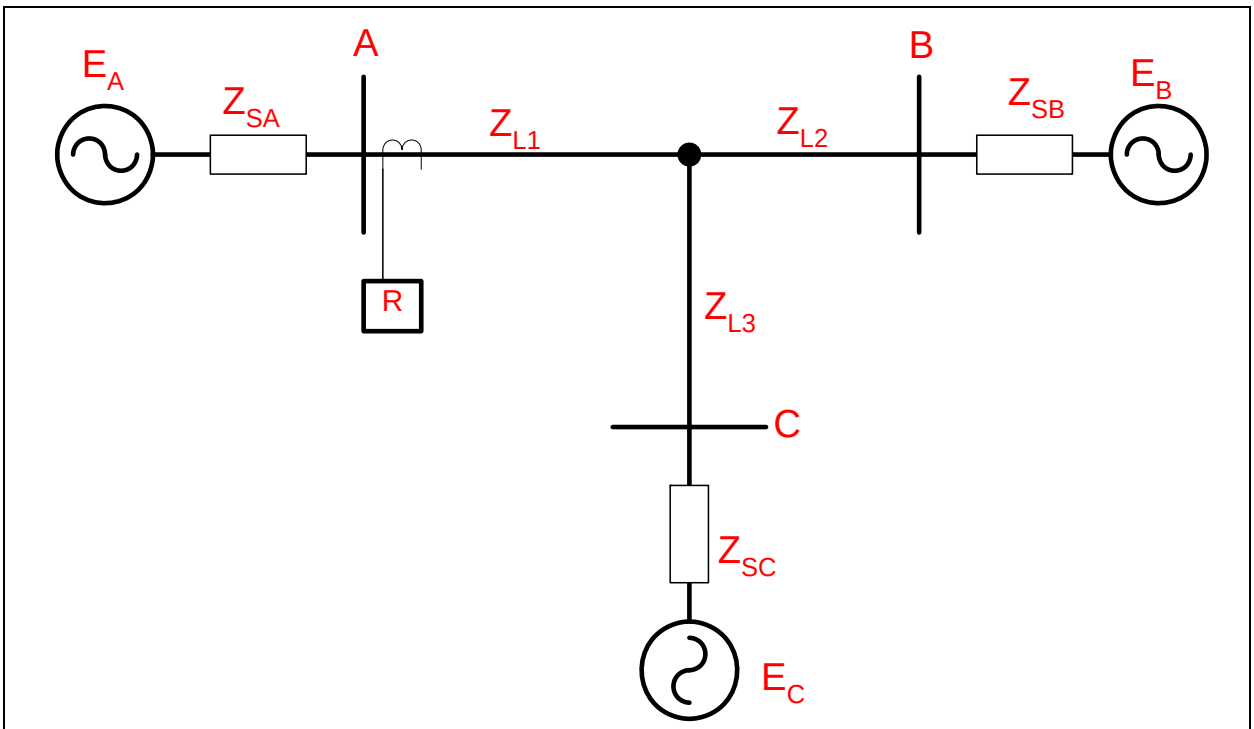

Figure 15j: Three-terminal line. To evaluate the load-responsive protective relays on the three-terminal line at Terminal A, the circuit in Figure 15j is first reduced to the equivalent circuit shown in Figure 15k. The evaluation process for the load-responsive protective relays on the line at Terminal A will now be the same as that of the two-terminal line.

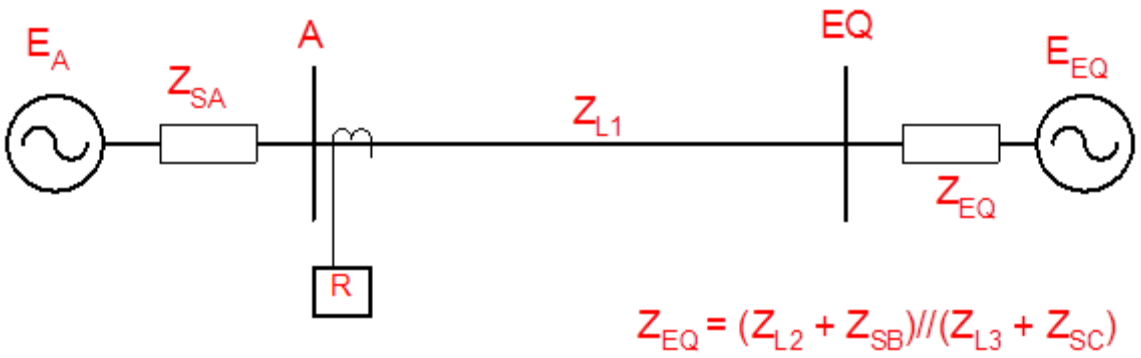

Figure 15k: Three-terminal line reduced to a two-terminal line.

Application to Generation Elements

As with transmission BES Elements, the determination of the apparent impedance seen at an Element located at, or near, a generation Facility is complex for power swings due to various interdependent quantities. These variances in quantities are caused by changes in machine internal voltage, speed governor action, voltage regulator action, the reaction of other local generators, and the reaction of other interconnected transmission BES Elements as the event progresses through the time domain. Though transient stability simulations may be used to determine the apparent impedance for verifying load-responsive relay settings,[19,20] Requirement R2, PRC-026-1 – Attachment B, Criteria A and B provides a simplified method for evaluating the load-responsive protective relay's susceptibility to tripping in response to a stable power swing without requiring stability simulations.

In general, the electrical center will be in the transmission system for cases where the generator is connected through a weak transmission system (high external impedance). In other cases where the generator is connected through a strong transmission system, the electrical center could be inside the unit connected zone.[21] In either case, load-responsive protective relays connected at the generator terminals or at the high-voltage side of the generator step-up (GSU) transformer may be challenged by power swings. Relays that may be challenged by power swings will be determined by the Planning Coordinator in Requirement R1 or by the Generator Owner after becoming aware of a generator, transformer, or transmission line BES Element that tripped[22] in response to a stable or unstable power swing due to the operation of its protective relay(s) in Requirement R2.

[19] Donald Reimert, *Protective Relaying for Power Generation Systems*, Boca Raton, FL, CRC Press, 2006.

[20] Prabha Kundur, *Power System Stability and Control*, EPRI, McGraw Hill, Inc., 1994.

[21] Ibid, Kundur.

[22] See Guidelines and Technical Basis section, "Becoming Aware of an Element That Tripped in Response to a Power Swing,"

Voltage controlled time-overcurrent and voltage-restrained time-overcurrent relays are excluded from this standard. When these relays are set based on equipment permissible overload capability, their operating times are much greater than 15 cycles for the current levels observed during a power swing.

Instantaneous overcurrent, time-overcurrent, and definite-time overcurrent relays with a time delay of less than 15 cycles for the current levels observed during a power swing are applicable and are required to be evaluated for identified Elements.

The generator loss-of-field protective function is provided by impedance relay(s) connected at the generator terminals. The settings are applied to protect the generator from a partial or complete loss of excitation under all generator loading conditions and, at the same time, be immune to tripping on stable power swings. It is more likely that the loss-of-field relay would operate during a power swing when the automatic voltage regulator (AVR) is in manual mode rather than when in automatic mode.[23] Figure 16 illustrates the loss-of-field relay in the R-X plot, which typically includes up to three zones of protection.

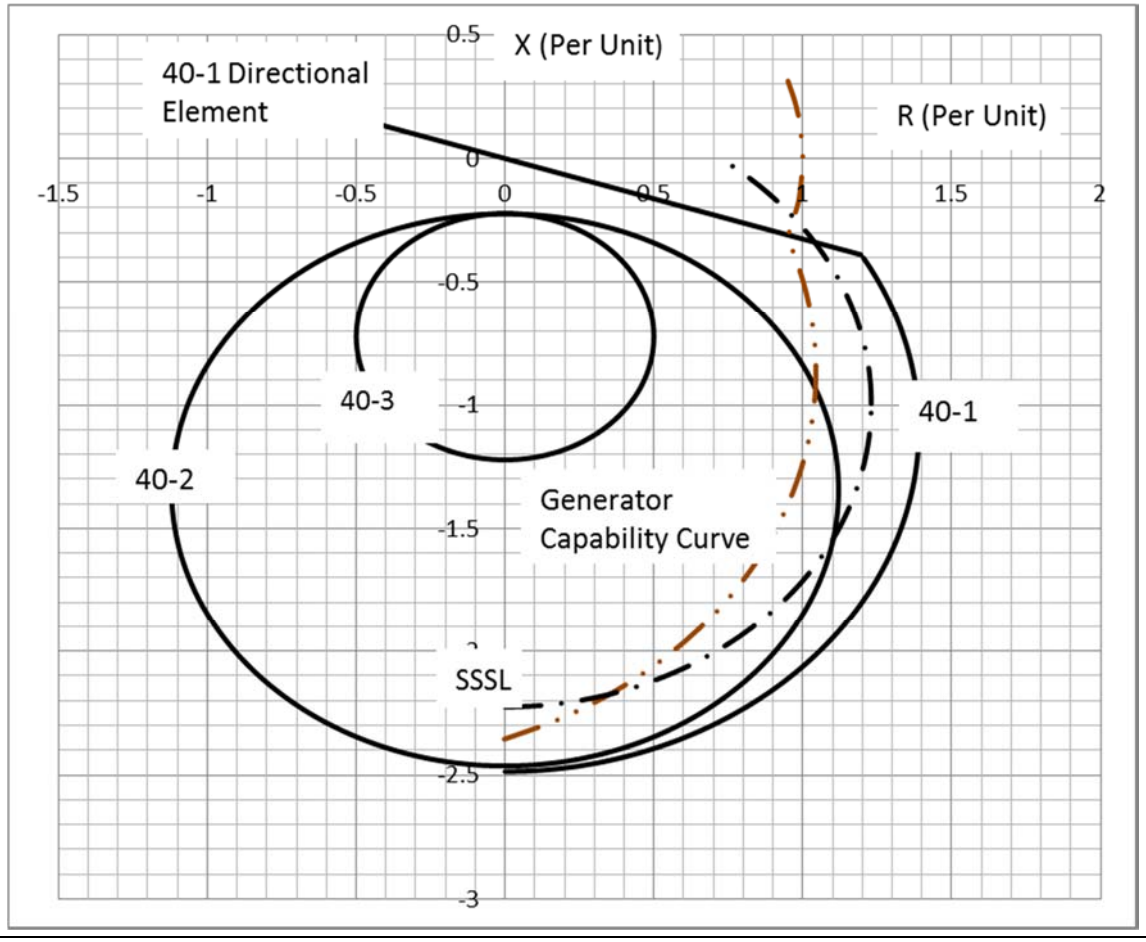

Figure 16: An R-X graph of typical impedance settings for loss-of-field relays.

[23] John Burdy, *Loss-of-excitation Protection for Synchronous Generators GER-3183*, General Electric Company.

Loss-of-field characteristic 40-1 has a wider impedance characteristic (positive offset) than characteristic 40-2 or characteristic 40-3 and provides additional generator protection for a partial loss of field or a loss of field under low load (less than 10% of rated). The tripping logic of this protection scheme is established by a directional contact, a voltage setpoint, and a time delay. The voltage and time delay add security to the relay operation for stable power swings. Characteristic 40-3 is less sensitive to power swings than characteristic 40-2 and is set outside the generator capability curve in the leading direction. Regardless of the relay impedance setting, PRC-019[24] requires that the "in-service limiters operate before Protection Systems to avoid unnecessary trip" and "in-service Protection System devices are set to isolate or de-energize equipment in order to limit the extent of damage when operating conditions exceed equipment capabilities or stability limits." Time delays for tripping associated with loss-of-field relays[25,26] have a range from 15 cycles for characteristic 40-2 to 60 cycles for characteristic 40-1 to minimize tripping during stable power swings. In PRC-026-1, 15 cycles establishes a threshold for applicability; however, it is the responsibility of the Generator Owner to establish settings that provide security against stable power swings and, at the same time, dependable protection for the generator.

The simple two-machine system circuit (method also used in the Application to Transmission Elements section) is used to analyze the effect of a power swing at a generator facility for load-responsive relays. In this section, the calculation method is used for calculating the impedance seen by the relay connected at a point in the circuit.[27] The electrical quantities used to determine the apparent impedance plot using this method are generator saturated transient reactance (X'_d), GSU transformer impedance (X_{GSU}), transmission line impedance (Z_L), and the system equivalent (Z_e) at the point of interconnection. All impedance values are known to the Generator Owner except for the system equivalent. The system equivalent is obtainable from the Transmission Owner. The sending-end and receiving-end source voltages are varied from 0.0 to 1.0 per unit to form the lens shape portion of the unstable power swing region. The voltage range of 0.7 to 1.0 results in a ratio range from 0.7 to 1.43. This ratio range is used to form the lower and upper loss-of-synchronism circle shapes of the unstable power swing region. A system separation angle of 120 degrees is used in accordance with PRC-026-1 – Attachment B criteria for each load-responsive protective relay evaluation.

Table 15 below is an example calculation of the apparent impedance locus method based on Figures 17 and 18.[28] In this example, the generator is connected to the 345 kV transmission system through the GSU transformer and has the listed ratings. Note that the load-responsive protective relays in this example may have ownership with the Generator Owner or the Transmission Owner.

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[24] Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

[25] Ibid, Burdy.

[26] *Applied Protective Relaying*, Westinghouse Electric Corporation, 1979.

[27] Edward Wilson Kimbark, *Power System Stability, Volume II: Power Circuit Breakers and Protective Relays*, Published by John Wiley and Sons, 1950.

[28] Ibid, Kimbark.

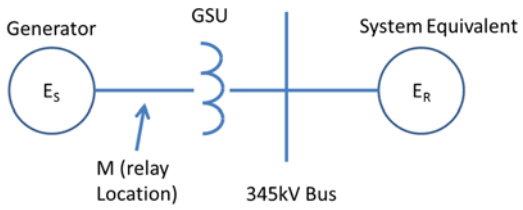

Figure 17: Simple one-line diagram of the system to be evaluated.

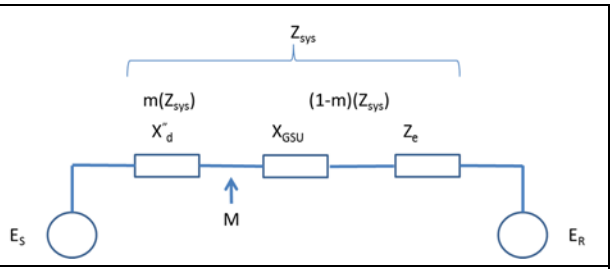

Figure 18: Simple system equivalent impedance diagram to be evaluated.[29]

Table15: Example Data (Generator)	
Input Descriptions	**Input Values**
Synchronous Generator nameplate (MVA)	940 MVA
Saturated transient reactance (940 MVA base)	$X'_d = 0.3845$ per unit
Generator rated voltage (Line-to-Line)	$20\ kV$
Generator step-up (GSU) transformer rating	$880\ MVA$
GSU transformer reactance (880 MVA base)	$X_{GSU} = 16.05\%$
System Equivalent (100 MVA base)	$Z_e = 0.00723\angle 90°$ per unit
Generator Owner Load-Responsive Protective Relays	
40-1	Positive Offset Impedance
	Offset = 0.294 per unit
	Diameter = 0.294 per unit
40-2	Negative Offset Impedance
	Offset = 0.22 per unit
	Diameter = 2.24 per unit
40-3	Negative Offset Impedance
	Offset = 0.22 per unit
	Diameter = 1.00 per unit
21-1	Diameter = 0.643 per unit
	MTA = 85°

[29] Ibid, Kimbark.

Table15: Example Data (Generator)	
50	I (pickup) = 5.0 per unit
Transmission Owned Load-Responsive Protective Relays	
21-2	Diameter = 0.55 per unit
	MTA = 85°

Calculations shown for a 120 degree angle and $E_S/E_R = 1$. The equation for calculating Z_R is:[30]

Eq. (106) $$Z_R = \left(\frac{(1-m)(E_S\angle\delta) + (m)(E_R)}{E_S\angle\delta - E_R}\right) \times Z_{sys}$$

Where m is the relay location as a function of the total impedance (real number less than 1)

E_S and E_R is the sending-end and receiving-end voltages

Z_{sys} is the total system impedance

Z_R is the complex impedance at the relay location and plotted on an R-X diagram

All of the above are constants (940 MVA base) while the angle δ is varied. Table 16 below contains calculations for a generator using the data listed in Table 15.

Table16: Example Calculations (Generator)			
The following calculations are on a 940 MVA base.			
Given:	$X'_d = j0.3845\ pu$	$X_{GSU} = j0.17144\ pu$	$Z_e = j0.06796\ pu$
Eq. (107)	$Z_{sys} = X'_d + X_{GSU} + Z_e$		
	$Z_{sys} = j0.3845\ pu + j0.17144\ pu + j0.06796\ pu$		
	$Z_{sys} = 0.6239\ \angle 90°\ pu$		
Eq. (108)	$m = \frac{X'_d}{Z_{sys}} = \frac{0.3845}{0.6239} = 0.6163$		
Eq. (109)	$Z_R = \left(\frac{(1-m)(E_S\angle\delta) + (m)(E_R)}{E_S\angle\delta - E_R}\right) \times Z_{sys}$		
	$Z_R = \left(\frac{(1-0.6163) \times (1\angle 120°) + (0.6163)(1\angle 0°)}{1\angle 120° - 1\angle 0°}\right) \times (0.6239\angle 90°)\ pu$		

[30] Ibid, Kimbark.

Table16: Example Calculations (Generator)	
	$Z_R = \left(\frac{0.4244 + j0.3323}{-1.5 + j\ 0.866}\right) \times (0.6239\angle 90°)\ pu$
	$Z_R = (0.3116 \angle -111.95°) \times (0.6239\angle 90°)\ pu$
	$Z_R = 0.194 \angle -21.95°\ pu$
	$Z_R = -0.18 - j0.073\ pu$

Table 17 lists the swing impedance values at other angles and at E_S/E_R = 1, 1.43, and 0.7. The impedance values are plotted on an R-X graph with the center being at the generator terminals for use in evaluating impedance relay settings.

Table 17: Sample Calculations for a Swing Impedance Chart for Varying Voltages at the Sending-End and Receiving-End.

	E_S/E_R=1		E_S/E_R=1.43		E_S/E_R=0.7	
	Z_R		Z_R		Z_R	
Angle (δ) (Degrees)	Magnitude (pu)	Angle (Degrees)	Magnitude (pu)	Angle (Degrees)	Magnitude (pu)	Angle (Degrees)
90	0.320	-13.1	0.296	6.3	0.344	-31.5
120	0.194	-21.9	0.173	-0.4	0.227	-40.1
150	0.111	-41.0	0.082	-10.3	0.154	-58.4
210	0.111	-25.9	0.082	190.3	0.154	238.4
240	0.194	201.9	0.173	180.4	0.225	220.1
270	0.320	193.1	0.296	173.7	0.344	211.5

Requirement R2 Generator Examples

Distance Relay Application

Based on PRC-026-1 – Attachment B, Criterion A, the distance relay (21-1) (i.e., owned by the Generation Owner) characteristic is in the region where a stable power swing would not occur as shown in Figure 19. There is no further obligation to the owner in this standard for this load-responsive protective relay.

The distance relay (21-2) (i.e., owned by the Transmission Owner) is connected at the high-voltage side of the GSU transformer and its impedance characteristic is in the region where a stable power swing could occur causing the relay to operate. In this example, if the intentional time delay of this relay is less than 15 cycles, the PRC-026 – Attachment B, Criterion A cannot be met, thus the Transmission Owner is required to create a CAP (Requirement R3). Some of the options include,

but are not limited to, changing the relay setting (i.e., impedance reach, angle, time delay), modify the scheme (i.e., add PSB), or replace the Protection System. Note that the relay may be excluded from this standard if it has an intentional time delay equal to or greater than 15 cycles.

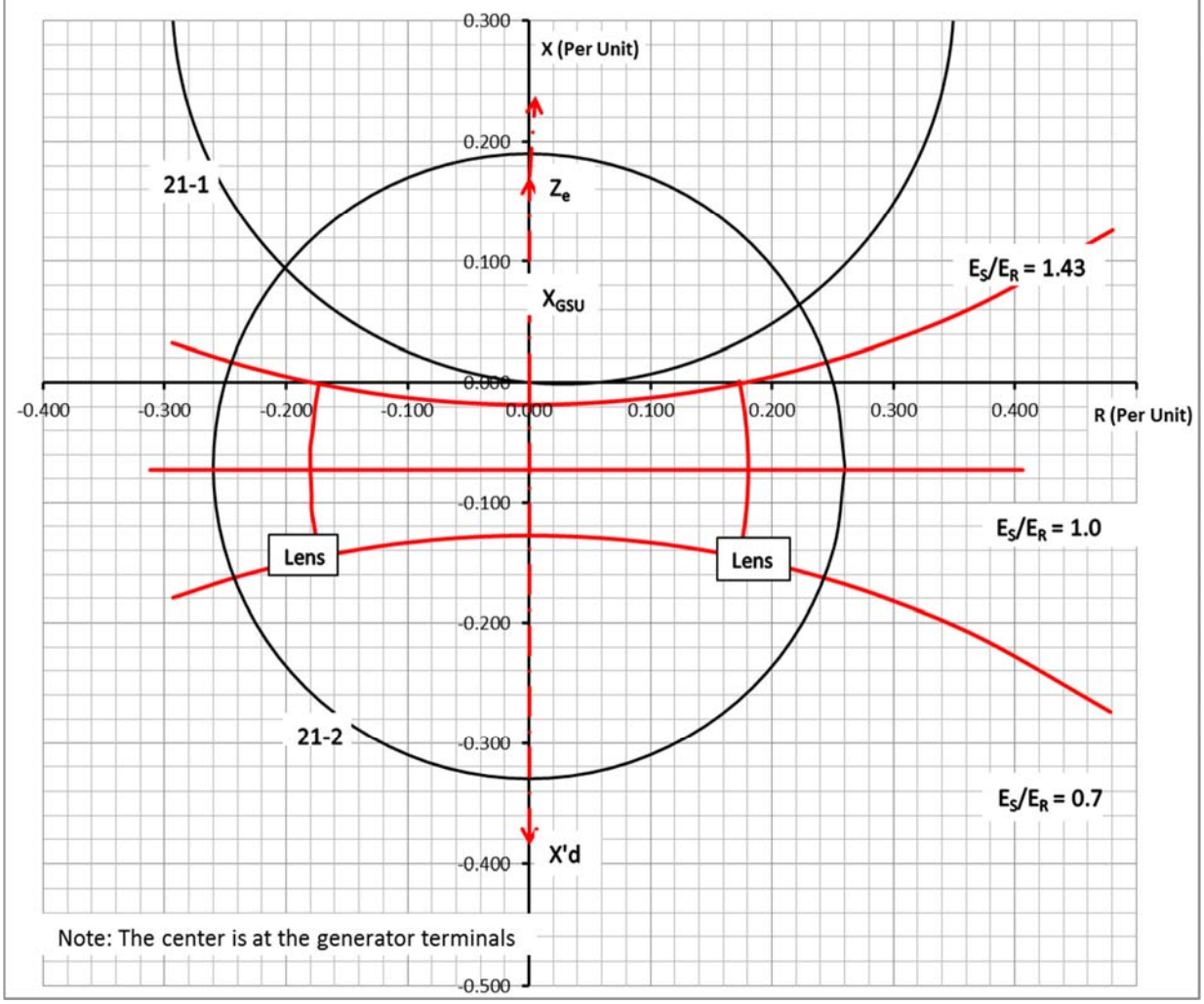

Figure 19: Swing impedance graph for impedance relays at a generating facility.

Loss-of-Field Relay Application

In Figure 20, the R-X diagram shows the loss-of-field relay (40-1 and 40-2) characteristics are in the region where a stable power swing can cause a relay operation. Protective relay 40-1 would be excluded if it has an intentional time delay equal to or greater than 15 cycles. Similarly, 40-2 would be excluded if its intentional time delay is equal to or greater than 15 cycles. For example, if 40-1 has a time delay of 1 second and 40-2 has a time delay of 0.25 seconds, they are excluded and there is no further obligation on the Generator Owner in this standard for these relays. The

loss-of-field relay characteristic 40-3 is entirely inside the unstable power swing region. In this case, the owner may select high speed tripping on operation of the 40-3 impedance element.

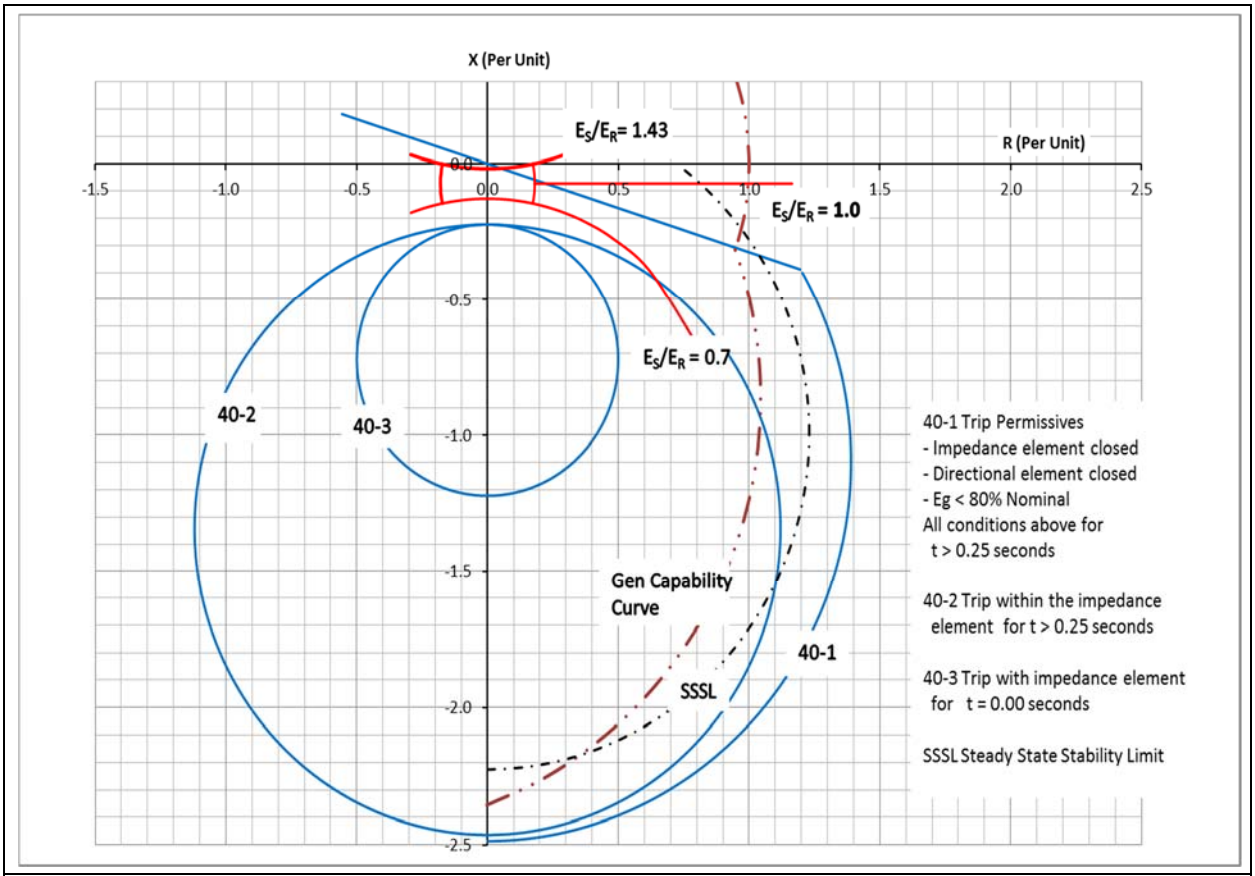

Figure 20: Typical R-X graph for loss-of-field relays with a portion of the unstable power swing region defined by PRC-026-1 – Attachment B, Criterion A.

Instantaneous Overcurrent Relay

In similar fashion to the transmission line overcurrent example calculation in Table 14, the instantaneous overcurrent relay minimum setting is established by PRC-026-1 – Attachment B, Criterion B. The solution is found by:

Eq. (110) $$I_{sys} = \frac{E_S - E_R}{Z_{\text{sys}}}$$

As stated in the relay settings in Table 15, the relay is installed on the high-voltage side of the GSU transformer with a pickup of 5.0 per unit. The maximum allowable current is calculated below.

$$I_{sys} = \frac{(1.05\angle 120° - 1.05\angle 0°)}{0.6239\angle 90°}\ pu$$

$$I_{sys} = \frac{1.819\angle 150°}{0.6239\angle 90°} pu$$

$$I_{sys} = 2.91\ \angle 60°\ pu$$

The instantaneous phase setting of 5.0 per unit is greater than the calculated system current of 2.91 per unit; therefore, it meets the PRC-026-1 – Attachment B, Criterion B.

Out-of-Step Tripping for Generation Facilities

Out-of-step protection for the generator generally falls into three different schemes. The first scheme is a distance relay connected at the high-voltage side of the GSU transformer with the directional element looking toward the generator. Because this relay setting may be the same setting used for generator backup protection (see Requirement R2 Generator Examples, Distance Relay Application), it is susceptible to tripping in response to stable power swings and would require modification. Because this scheme is susceptible to tripping in response to stable power swings and any modification to the mho circle will jeopardize the overall protection of the out-of-step protection of the generator, available technical literature does not recommend using this scheme specifically for generator out-of-step protection. The second and third out-of-step Protection System schemes are commonly referred to as single and double blinder schemes. These schemes are installed or enabled for out-of-step protection using a combination of blinders, a mho element, and timers. The combination of these protective relay functions provides out-of-step protection and discrimination logic for stable and unstable power swings. Single blinder schemes use logic that discriminate between stable and unstable power swings by issuing a trip command after the first slip cycle. Double blinder schemes are more complex than the single blinder scheme and, depending on the settings of the inner blinder, a trip for a stable power swing may occur. While the logic discriminates between stable and unstable power swings in either scheme, it is important that the trip initiating blinders be set at an angle greater than the stability limit of 120 degrees to remove the possibility of a trip for a stable power swing. Below is a discussion of the double blinder scheme.

Double Blinder Scheme

The double blinder scheme is a method for measuring the rate of change of positive sequence impedance for out-of-step swing detection. The scheme compares a timer setting to the actual elapsed time required by the impedance locus to pass between two impedance characteristics. In this case, the two impedance characteristics are simple blinders, each set to a specific resistive reach on the R-X plane. Typically, the two blinders on the left half plane are the mirror images of those on the right half plane. The scheme typically includes a mho characteristic which acts as a starting element, but is not a tripping element.

The scheme detects the blinder crossings and time delays as represented on the R-X plane as shown in Figure 21. The system impedance is composed of the generator transient (X_d'), GSU transformer (X_T), and transmission system (X_{system}), impedances.

The scheme logic is initiated when the swing locus crosses the outer Blinder R1 (Figure 21), on the right at separation angle α. The scheme only commits to take action when a swing crosses the

inner blinder. At this point the scheme logic seals in the out-of-step trip logic at separation angle β. Tripping actually asserts as the impedance locus leaves the scheme characteristic at separation angle δ.

The power swing may leave both inner and outer blinders in either direction, and tripping will assert. Therefore, the inner blinder must be set such that the separation angle β is large enough that the system cannot recover. This angle should be set at 120 degrees or more. Setting the angle greater than 120 degrees satisfies the PRC-026-1 – Attachment B, Criterion A (No. 1, 1st bullet) since the tripping function is asserted by the blinder element. Transient stability studies may indicate that a smaller stability limit angle is acceptable under PRC-026-1 – Attachment B, Criterion A (No. 1, 2nd bullet). In this respect, the double blinder scheme is similar to the double lens and triple lens schemes and many transmission application out-of-step schemes.

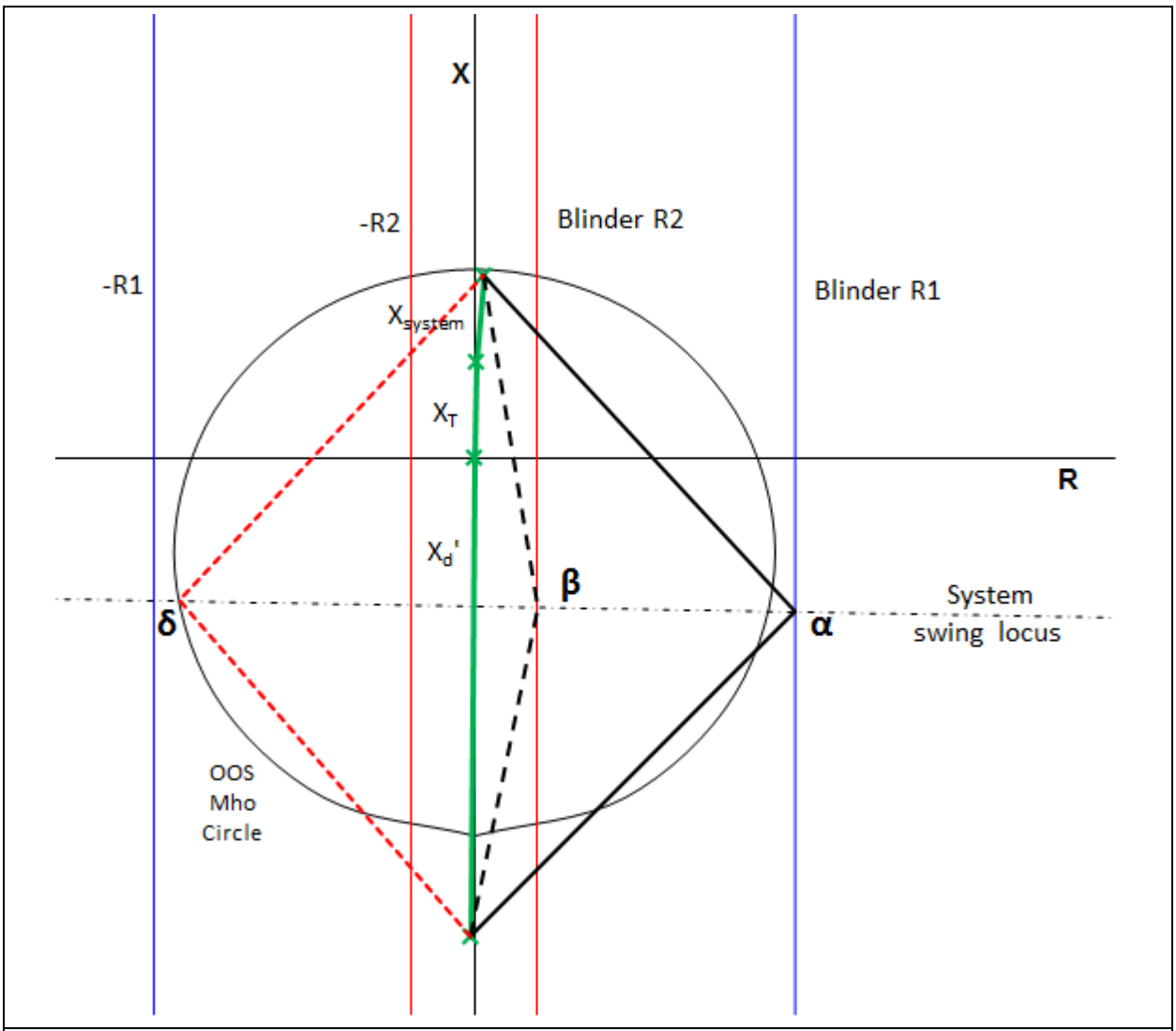

Figure 21: Double Blinder Scheme generic out of step characteristics.

Figure 22 illustrates a sample setting of the double blinder scheme for the example 940 MVA generator. The only setting requirement for this relay scheme is the right inner blinder, which must be set greater than the separation angle of 120 degrees (or a lesser angle based on a transient stability study) to ensure that the out-of-step protective function is expected to not trip in response to a stable power swing during non-Fault conditions. Other settings such as the mho characteristic, outer blinders, and timers are set according to transient stability studies and are not a part of this standard.

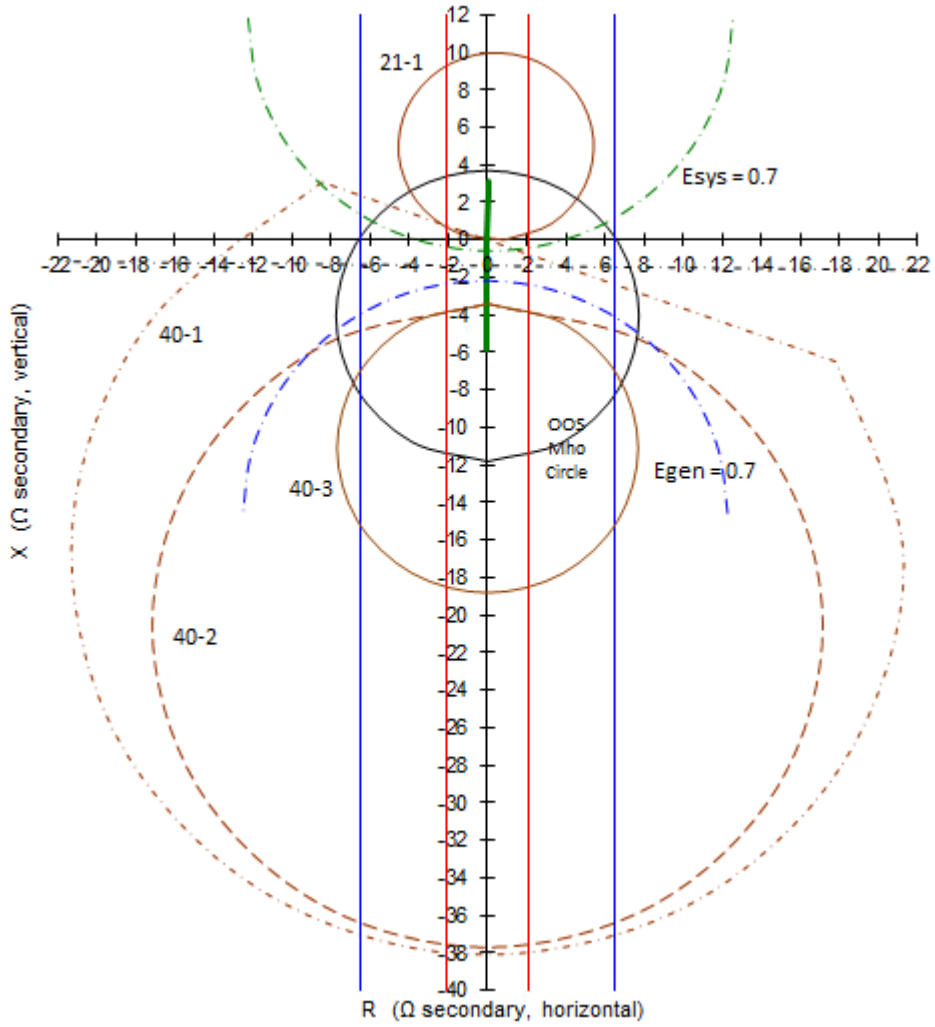

Figure 22: Double Blinder Out-of-Step Scheme with unit impedance data and load-responsive protective relay impedance characteristics for the example 940 MVA generator, scaled in relay secondary ohms.

Requirement R3

To achieve the stated purpose of this standard, which is to ensure that relays are expected to not trip in response to stable power swings during non-Fault conditions, this Requirement ensures that the applicable entity develops a Corrective Action Plan (CAP) that reduces the risk of relays tripping in response to a stable power swing during non-Fault conditions that may occur on any applicable BES Element.

Requirement R4

To achieve the stated purpose of this standard, which is to ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions, the applicable entity is required to implement any CAP developed pursuant to Requirement R3 such that the Protection System will meet PRC-026-1 – Attachment B criteria or can be excluded under the PRC-026-1 – Attachment A criteria (e.g., modifying the Protection System so that relay functions are supervised by power swing blocking or using relay systems that are immune to power swings), while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the BES Element). Protection System owners are required in the implementation of a CAP to update it when actions or timetable change, until all actions are complete. Accomplishing this objective is intended to reduce the occurrence of Protection System tripping during a stable power swing, thereby improving reliability and minimizing risk to the BES.

The following are examples of actions taken to complete CAPs for a relay that did not meet PRC-026-1 – Attachment B and could be at-risk of tripping in response to a stable power swing during non-Fault conditions. A Protection System change was determined to be acceptable (without diminishing the ability of the relay to protect for faults within its zone of protection).

> **Example R4a:** Actions: Settings were issued on 6/02/2015 to reduce the Zone 2 reach of the impedance relay used in the directional comparison unblocking (DCUB) scheme from 30 ohms to 25 ohms so that the relay characteristic is completely contained within the lens characteristic identified by the criterion. The settings were applied to the relay on 6/25/2015. CAP was completed on 06/25/2015.
>
> **Example R4b:** Actions: Settings were issued on 6/02/2015 to enable out-of-step blocking on the existing microprocessor-based relay to prevent tripping in response to stable power swings. The setting changes were applied to the relay on 6/25/2015. CAP was completed on 06/25/2015.

The following is an example of actions taken to complete a CAP for a relay responding to a stable power swing that required the addition of an electromechanical power swing blocking relay.

> **Example R4c:** Actions: A project for the addition of an electromechanical power swing blocking relay to supervise the Zone 2 impedance relay was initiated on 6/5/2015 to prevent tripping in response to stable power swings. The relay installation was completed on 9/25/2015. CAP was completed on 9/25/2015.

The following is an example of actions taken to complete a CAP with a timetable that required updating for the replacement of the relay.

> **Example R4d:** Actions: A project for the replacement of the impedance relays at both terminals of line X with line current differential relays was initiated on 6/5/2015 to prevent tripping in response to stable power swings. The completion of the project was postponed due to line outage rescheduling from 11/15/2015 to 3/15/2016. Following the timetable change, the impedance relay replacement was completed on 3/18/2016. CAP was completed on 3/18/2016.

The CAP is complete when all the documented actions to remedy the specific problem (i.e., unnecessary tripping during stable power swings) are completed.

Justification for Including Unstable Power Swings in the Requirements

Protection Systems that are applicable to the Standard and must be secure for a stable power swing condition (i.e., meets PRC-026-1 – Attachment B criteria) are identified based on Elements that are susceptible to both stable and unstable power swings. This section provides an example of why Elements that trip in response to unstable power swings (in addition to stable power swings) are identified and that their load-responsive protective relays need to be evaluated under PRC-026-1 – Attachment B criteria.

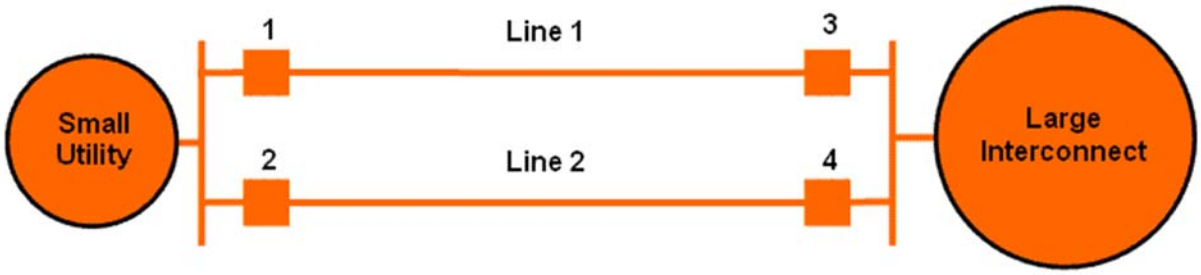

Figure 23: A simple electrical system where two lines tie a small utility to a much larger interconnection.

In Figure 23 the relays at circuit breakers 1, 2, 3, and 4 are equipped with a typical overreaching Zone 2 pilot system, using a Directional Comparison Blocking (DCB) scheme. Internal faults (or power swings) will result in instantaneous tripping of the Zone 2 relays if the measured fault or power swing impedance falls within the zone 2 operating characteristic. These lines will trip on

pilot Zone 2 for out-of-step conditions if the power swing impedance characteristic enters into Zone 2. All breakers are rated for out-of-phase switching.

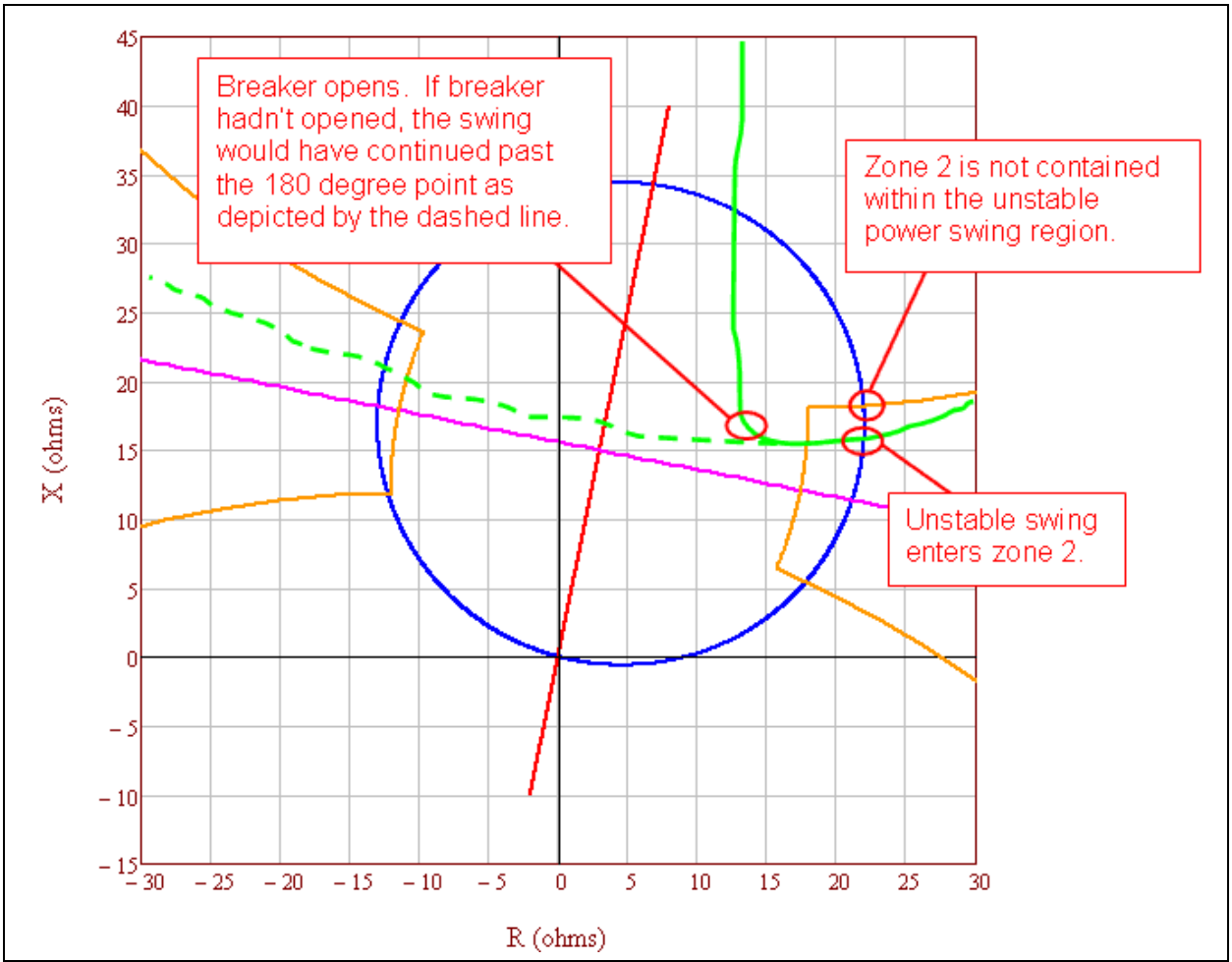

Figure 24: In this case, the Zone 2 element on circuit breakers 1, 2, 3, and 4 did not meet the PRC-026-1 – Attachment B criteria (this figure depicts the power swing as seen by relays on breakers 3 and 4).

In Figure 24, a large disturbance occurs within the small utility and its system goes out-of-step with the large interconnect. The small utility is importing power at the time of the disturbance. The actual power swing, as shown by the solid green line, enters the Zone 2 relay characteristic on the terminals of Lines 1, 2, 3, and 4 causing both lines to trip as shown in Figure 25.

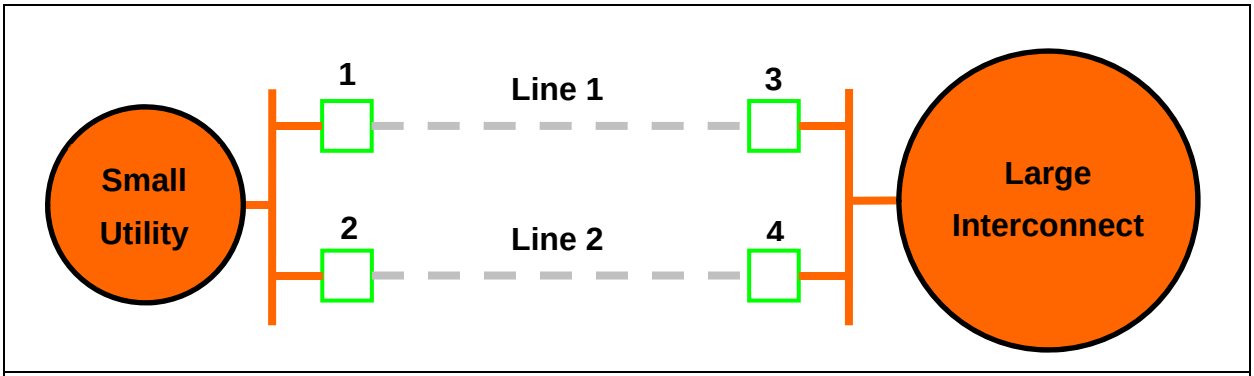

Figure 25: Islanding of the small utility due to Lines 1 and 2 tripping in response to an unstable power swing.

In Figure 25, the relays at circuit breakers 1, 2, 3, and 4 have correctly tripped due to the unstable power swing (shown by the dashed green line in Figure 24), de-energizing Lines 1 and 2, and creating an island between the small utility and the big interconnect. The small utility shed 500 MW of load on underfrequency and maintained a load to generation balance.

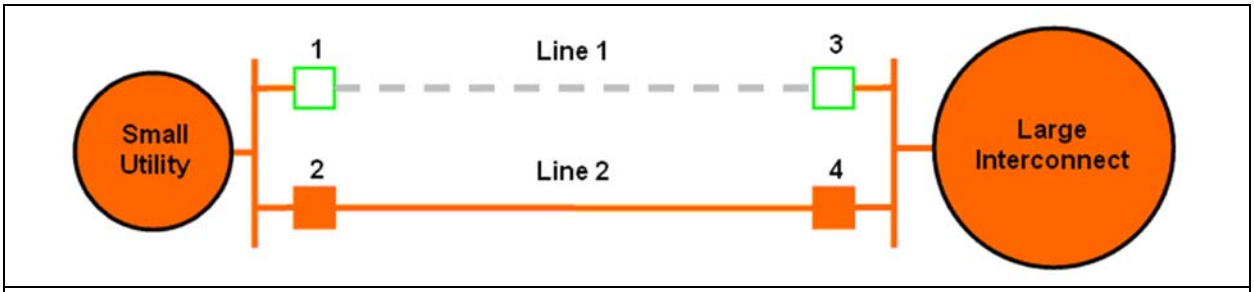

Figure 26: Line 1 is out-of-service for maintenance, Line 2 is loaded beyond its normal rating (but within its emergency rating).

Subsequent to the correct tripping of Lines 1 and 2 for the unstable power swing in Figure 25, another system disturbance occurs while the system is operating with Line 1 out-of-service for maintenance. The disturbance causes a stable power swing on Line 2, which challenges the relays at circuit breakers 2 and 4 as shown in Figure 27.

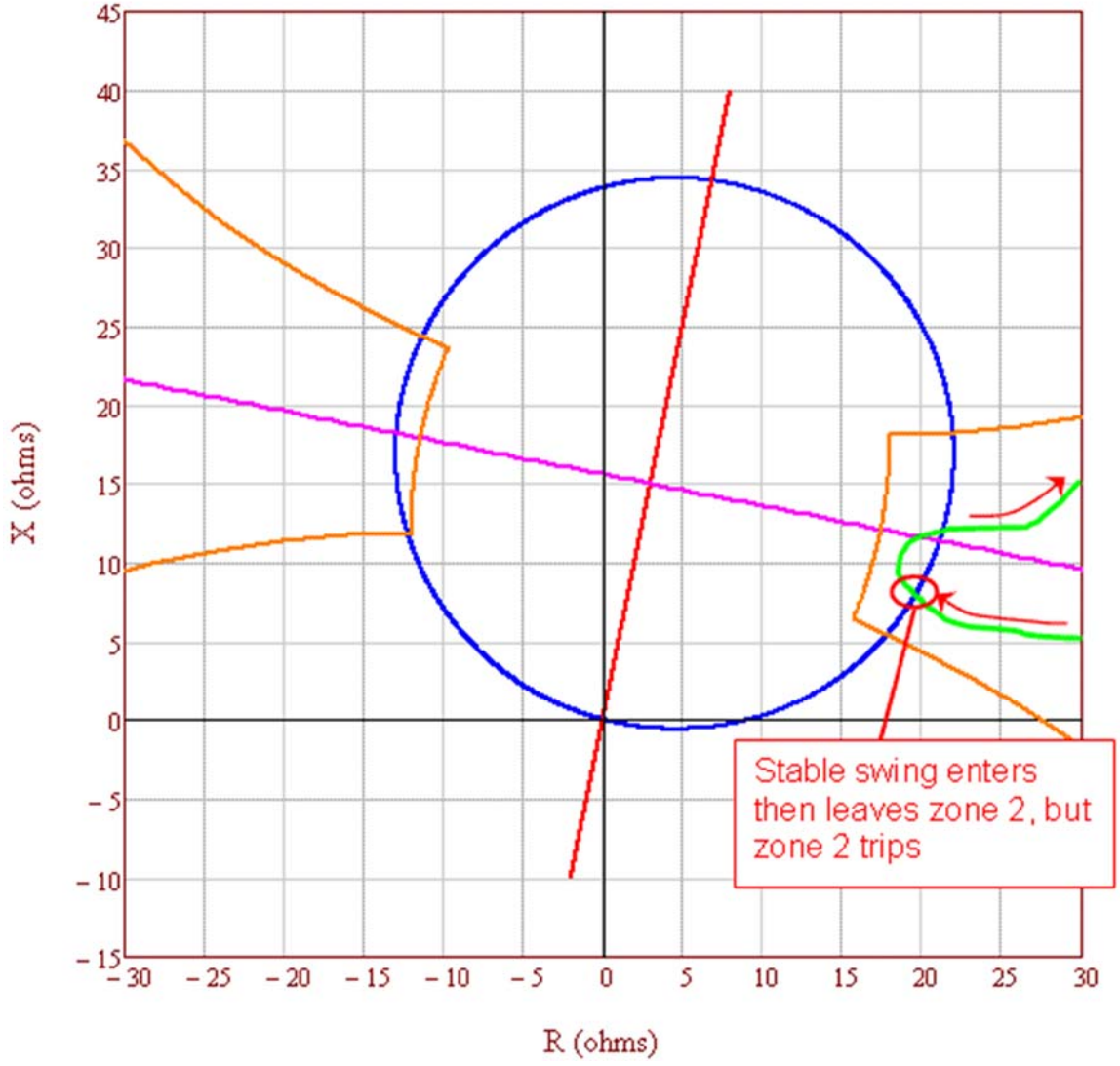

Figure 27: Relays on circuit breakers 2 and 4 were not addressed to meet the PRC-026-1 – Attachment B criteria following the previous unstable power swing event.

If the relays on circuit breakers 2 and 4 were not addressed under the Requirements for the previous unstable power swing condition, the relays would trip in response to the stable power swing, which would result in unnecessary system separation, load shedding, and possibly cascading or blackout.

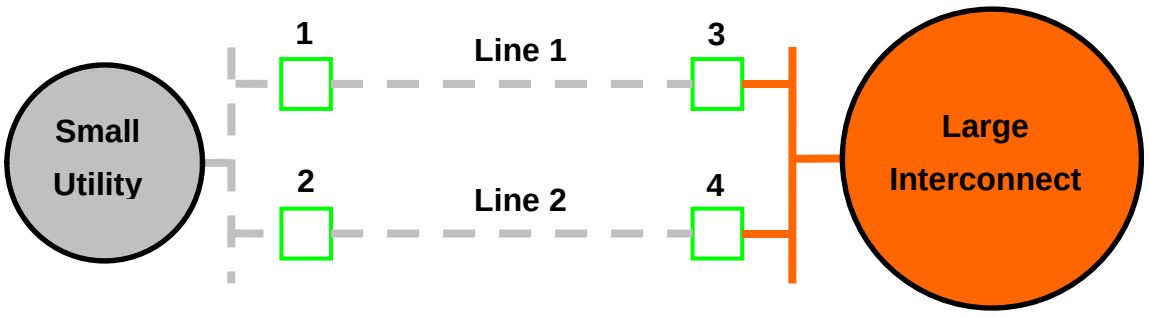

Figure 28: Possible blackout of the small utility.

If the relays that tripped in response to the previous unstable power swing condition in Figure 24 were addressed under the Requirements to meet PRC-026-1 - Attachment B criteria, the unnecessary tripping of the relays for the stable power swing shown in Figure 28 would have been averted, and the possible blackout of the small utility would have been avoided.

Rationale

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

Rationale for R1

The Planning Coordinator has a wide-area view and is in the position to identify generator, transformer, and transmission line BES Elements which meet the criteria, if any. The criteria-based approach is consistent with the NERC System Protection and Control Subcommittee (SPCS) technical document *Protection System Response to Power Swings*, August 2013 ("PSRPS Report"),[31] which recommends a focused approach to determine an at-risk BES Element. See the Guidelines and Technical Basis for a detailed discussion of the criteria.

Rationale for R2

The Generator Owner and Transmission Owner are in a position to determine whether their load-responsive protective relays meet the PRC-026-1 – Attachment B criteria. Generator, transformer, and transmission line BES Elements are identified by the Planning Coordinator in Requirement R1 and by the Generator Owner and Transmission Owner following an actual event where the Generator Owner and Transmission Owner became aware (i.e., through an event analysis or

[31] NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

Protection System review) tripping was due to a stable or unstable power swing. A period of 12 calendar months allows sufficient time for the entity to conduct the evaluation.

Rationale for R3

To meet the reliability purpose of the standard, a CAP is necessary to ensure the entity's Protection System meets the PRC-026-1 – Attachment B criteria (1st bullet) so that protective relays are expected to not trip in response to stable power swings. A CAP may also be developed to modify the Protection System for exclusion under PRC-026-1 – Attachment A (2nd bullet). Such an exclusion will allow the Protection System to be exempt from the Requirement for future events. The phrase, "…while maintaining dependable fault detection and dependable out-of-step tripping…" in Requirement R3 describes that the entity is to comply with this standard, while achieving their desired protection goals. Refer to the Guidelines and Technical Basis, Introduction, for more information.

Rationale for R4

Implementation of the CAP must accomplish all identified actions to be complete to achieve the desired reliability goal. During the course of implementing a CAP, updates may be necessary for a variety of reasons such as new information, scheduling conflicts, or resource issues. Documenting CAP changes and completion of activities provides measurable progress and confirmation of completion.

Rationale for Attachment B (Criterion A)

The PRC-026-1 – Attachment B, Criterion A provides a basis for determining if the relays are expected to not trip for a stable power swing having a system separation angle of up to 120 degrees with the sending-end and receiving-end voltages varying from 0.7 to 1.0 per unit (See Guidelines and Technical Basis).

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 initial ballot	June 2018 – July 2018
10-day final ballot	September 2018
NERC Board adoption	November 2018

A. Introduction

1. **Title:** **Relay Performance During Stable Power Swings**

2. **Number:** **PRC-026-2**

3. **Purpose:** To ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Generator Owner that applies load-responsive protective relays as described in PRC-026-1 – Attachment A at the terminals of the Elements listed in Section 4.2, Facilities.

   4.1.2 Planning Coordinator.

   4.1.3 Transmission Owner that applies load-responsive protective relays as described in PRC-026-1 – Attachment A at the terminals of the Elements listed in Section 4.2, Facilities.

   4.2. Facilities: The following Elements that are part of the Bulk Electric System (BES):

   4.2.1 Generators.

   4.2.2 Transformers.

   4.2.3 Transmission lines.

5. **Background:**

   This is the third phase of a three-phased standard development project that focused on developing this new Reliability Standard to address protective relay operations due to stable power swings. The March 18, 2010, Federal Energy Regulatory Commission (FERC) Order No. 733 approved Reliability Standard PRC-023-1 – Transmission Relay Loadability. In that Order, FERC directed NERC to address three areas of relay loadability that include modifications to the approved PRC-023-1, development of a new Reliability Standard to address generator protective relay loadability, and a new Reliability Standard to address the operation of protective relays due to stable power swings. This project's SAR addresses these directives with a three-phased approach to standard development.

   Phase 1 focused on making the specific modifications from FERC Order No. 733 to PRC-023-1. Reliability Standard PRC-023-2, which incorporated these modifications, became mandatory on July 1, 2012.

   Phase 2 focused on developing a new Reliability Standard, PRC-025-1 – Generator Relay Loadability, to address generator protective relay loadability. PRC-025-1 became mandatory on October 1, 2014, along with PRC-023-3, which was modified to harmonize PRC-023-2 with PRC-025-1.

   Phase 3 focuses on preventing protective relays from tripping unnecessarily due to stable power swings by requiring identification of Elements on which a stable or unstable power

swing may affect Protection System operation, assessment of the security of load-responsive protective relays to tripping in response to only a stable power swing, and implementation of Corrective Action Plans (CAP), where necessary. Phase 3 improves security of load-responsive protective relays for stable power swings so they are expected to not trip in response to stable power swings during non-Fault conditions while maintaining dependable fault detection and dependable out-of-step tripping.

6. Effective Dates:

Requirement R1

First day of the first full calendar year that is 12 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first full calendar year that is 12 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Requirements R2, R3, and R4

First day of the first full calendar year that is 36 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first full calendar year 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.

B. Requirements and Measures

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

Criteria:

1. Generator(s) where an angular stability constraint exists that is addressed by a limiting the output of a generator or a Remedial Action Scheme (RAS), and those Elements terminating at the Transmission station associated with the generator(s).
2. Elements associated with angular instability identified in Planning Assessments.
3. An Element that forms the boundary of an island in the most recent underfrequency load shedding (UFLS) design assessment based on application of the Planning Coordinator's criteria for identifying islands, only if the island is formed by tripping the Element due to angular instability.
4. An Element identified in the most recent annual Planning Assessment where relay tripping occurs due to a stable or unstable[1] power swing during a simulated disturbance.

M1. Each Planning Coordinator shall have dated evidence that demonstrates notification of the generator, transformer, and transmission line BES Element(s) that meet one or more of the criteria in Requirement R1, if any, to the respective Generator Owner and Transmission Owner. Evidence may include, but is not limited to, the following documentation: emails, facsimiles, records, reports, transmittals, lists, or spreadsheets.

[1] An example of an unstable power swing is provided in the Guidelines and Technical Basis section, "Justification for Including Unstable Power Swings in the Requirements section of the Guidelines and Technical Basis."

R2. Each Generator Owner and Transmission Owner shall: [Violation Risk Factor: High] [Time Horizon: Operations Planning]

2.1 Within 12 full calendar months of notification of a BES Element pursuant to Requirement R1, determine whether its load-responsive protective relay(s) applied to that BES Element meets the criteria in PRC-026-1 – Attachment B where an evaluation of that Element's load-responsive protective relay(s) based on PRC-026-1 – Attachment B criteria has not been performed in the last five calendar years.

2.2 Within 12 full calendar months of becoming aware[2] of a generator, transformer, or transmission line BES Element that tripped in response to a stable or unstable[3] power swing due to the operation of its protective relay(s), determine whether its load-responsive protective relay(s) applied to that BES Element meets the criteria in PRC-026-1 – Attachment B.

M2. Each Generator Owner and Transmission Owner shall have dated evidence that demonstrates the evaluation was performed according to Requirement R2. Evidence may include, but is not limited to, the following documentation: apparent impedance characteristic plots, email, design drawings, facsimiles, R-X plots, software output, records, reports, transmittals, lists, settings sheets, or spreadsheets.

R3. Each Generator Owner and Transmission Owner shall, within six full calendar months of determining a load-responsive protective relay does not meet the PRC-026-1 – Attachment B criteria pursuant to Requirement R2, develop a Corrective Action Plan (CAP) to meet one of the following: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

- The Protection System meets the PRC-026-1 – Attachment B criteria, while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the BES Element); or
- The Protection System is excluded under the PRC-026-1 – Attachment A criteria (e.g., modifying the Protection System so that relay functions are supervised by power swing blocking or using relay systems that are immune to power swings), while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the BES Element).

M3. The Generator Owner and Transmission Owner shall have dated evidence that demonstrates the development of a CAP in accordance with Requirement R3. Evidence may include, but is not limited to, the following documentation: corrective action plans, maintenance records, settings sheets, project or work management program records, or work orders.

R4. Each Generator Owner and Transmission Owner shall implement each CAP developed pursuant to Requirement R3 and update each CAP if actions or timetables change until all actions are complete. *[Violation Risk Factor: Medium][Time Horizon: Long-Term Planning]*

M4. The Generator Owner and Transmission Owner shall have dated evidence that demonstrates implementation of each CAP according to Requirement R4, including updates to the CAP when actions or timetables change. Evidence may include, but is not limited to, the following documentation: corrective action plans, maintenance records, settings sheets, project or work management program records, or work orders.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

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

The Generator Owner, Planning Coordinator, and Transmission Owner shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

- The Planning Coordinator shall retain evidence of Requirement R1 for a minimum of one calendar year following the completion of the Requirement.
- The Generator Owner and Transmission Owner shall retain evidence of Requirement R2 evaluation for a minimum of 12 calendar months following completion of each evaluation where a CAP is not developed.
- The Generator Owner and Transmission Owner shall retain evidence of Requirements R2, R3, and R4 for a minimum of 12 calendar months following completion of each CAP.

If a Generator Owner, Planning Coordinator, or Transmission 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.

[2] Some examples of the ways an entity may become aware of a power swing are provided in the Guidelines and Technical Basis section, "Becoming Aware of an Element That Tripped in Response to a Power Swing."

[3] An example of an unstable power swing is provided in the Guidelines and Technical Basis section, "Justification for Including Unstable Power Swings in the Requirements section of the Guidelines and Technical Basis."

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

As defined in the NERC Rules of Procedure; "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Medium	The Planning Coordinator provided notification of the BES Element(s) in accordance with Requirement R1, but was less than or equal to 30 calendar days late.	The Planning Coordinator provided notification of the BES Element(s) in accordance with Requirement R1, but was more than 30 calendar days and less than or equal to 60 calendar days late.	The Planning Coordinator provided notification of the BES Element(s) in accordance with Requirement R1, but was more than 60 calendar days and less than or equal to 90 calendar days late.	The Planning Coordinator provided notification of the BES Element(s) in accordance with Requirement R1, but was more than 90 calendar days late. OR The Planning Coordinator failed to provide notification of the BES Element(s) in accordance with Requirement R1.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Operations Planning	High	The Generator Owner or Transmission Owner evaluated its load-responsive protective relay(s) in accordance with Requirement R2, but was less than or equal to 30 calendar days late.	The Generator Owner or Transmission Owner evaluated its load-responsive protective relay(s) in accordance with Requirement R2, but was more than 30 calendar days and less than or equal to 60 calendar days late.	The Generator Owner or Transmission Owner evaluated its load-responsive protective relay(s) in accordance with Requirement R2, but was more than 60 calendar days and less than or equal to 90 calendar days late.	The Generator Owner or Transmission Owner evaluated its load-responsive protective relay(s) in accordance with Requirement R2, but was more than 90 calendar days late. OR The Generator Owner or Transmission Owner failed to evaluate its load-responsive protective relay(s) in accordance with Requirement R2.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	Long-term Planning	Medium	The Generator Owner or Transmission Owner developed a Corrective Action Plan (CAP) in accordance with Requirement R3, but in more than six calendar months and less than or equal to seven calendar months.	The Generator Owner or Transmission Owner developed a Corrective Action Plan (CAP) in accordance with Requirement R3, but in more than seven calendar months and less than or equal to eight calendar months.	The Generator Owner or Transmission Owner developed a Corrective Action Plan (CAP) in accordance with Requirement R3, but in more than eight calendar months and less than or equal to nine calendar months.	The Generator Owner or Transmission Owner developed a Corrective Action Plan (CAP) in accordance with Requirement R3, but in more than nine calendar months. OR The Generator Owner or Transmission Owner failed to develop a CAP in accordance with Requirement R3.
R4	Long-term Planning	Medium	The Generator Owner or Transmission Owner implemented a Corrective Action Plan (CAP), but failed to update a CAP when actions or timetables changed, in accordance with Requirement R4.	N/A	N/A	The Generator Owner or Transmission Owner failed to implement a Corrective Action Plan (CAP) in accordance with Requirement R4.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

Applied Protective Relaying, Westinghouse Electric Corporation, 1979.

Burdy, John, *Loss-of-excitation Protection for Synchronous Generators GER-3183*, General Electric Company.

IEEE Power System Relaying Committee WG D6, *Power Swing and Out-of-Step Considerations on Transmission Lines*, July 2005: http://www.pes-psrc.org/Reports/Power%20Swing%20and%20OOS%20Considerations%20on%20Transmission%20Lines%20F..pdf.

Kimbark Edward Wilson, *Power System Stability, Volume II: Power Circuit Breakers and Protective Relays*, Published by John Wiley and Sons, 1950.

Kundur, Prabha, *Power System Stability and Control*, 1994, Palo Alto: EPRI, McGraw Hill, Inc.

NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf.

Reimert, Donald, *Protective Relaying for Power Generation Systems*, 2006, Boca Raton: CRC Press.

Version History

Version	Date	Action	Change Tracking
1	November 13, 2014	Adopted by NERC Board of Trustees	New
1	March 17, 2016	FERC Order issued approving PRC-026-1. Docket No. RM15-8-000.	

PRC-026-1 – Attachment A

This standard applies to any protective functions which could trip instantaneously or with a time delay of less than 15 cycles on load current (i.e., "load-responsive") including, but not limited to:

- Phase distance
- Phase overcurrent
- Out-of-step tripping
- Loss-of-field

The following protection functions are excluded from Requirements of this standard:

- Relay elements supervised by power swing blocking
- Relay elements that are only enabled when other relays or associated systems fail. For example:
    - Overcurrent elements that are only enabled during loss of potential conditions.
    - Relay elements that are only enabled during a loss of communications
- Thermal emulation relays which are used in conjunction with dynamic Facility Ratings
- Relay elements associated with direct current (dc) lines
- Relay elements associated with dc converter transformers
- Phase fault detector relay elements employed to supervise other load-responsive phase distance elements (i.e., in order to prevent false operation in the event of a loss of potential)
- Relay elements associated with switch-onto-fault schemes
- Reverse power relay on the generator
- Generator 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)
- Current differential relay, pilot wire relay, and phase comparison relay
- Voltage-restrained or voltage-controlled overcurrent relays

PRC-026-1 – Attachment B

Criterion A:

An impedance-based relay used for tripping is expected to not trip for a stable power swing, when the relay characteristic is completely contained within the unstable power swing region.[4] The unstable power swing region is formed by the union of three shapes in the impedance (R-X) plane; (1) a lower loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 0.7; (2) an upper loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 1.43; (3) a lens that connects the endpoints of the total system impedance (with the parallel transfer impedance removed) bounded by varying the sending-end and receiving-end voltages from 0.0 to 1.0 per unit, while maintaining a constant system separation angle across the total system impedance where:

1. The system separation angle is:
   - At least 120 degrees, or
   - An angle less than 120 degrees where a documented transient stability analysis demonstrates that the expected maximum stable separation angle is less than 120 degrees.
2. All generation is in service and all transmission BES Elements are in their normal operating state when calculating the system impedance.
3. Saturated (transient or sub-transient) reactance is used for all machines.

[4] Guidelines and Technical Basis, Figures 1 and 2.

PRC-026-1 – Attachment B

Criterion B:

The pickup of an overcurrent relay element used for tripping, that is above the calculated current value (with the parallel transfer impedance removed) for the conditions below:

1. The system separation angle is:
   - At least 120 degrees, or
   - An angle less than 120 degrees where a documented transient stability analysis demonstrates that the expected maximum stable separation angle is less than 120 degrees.
2. All generation is in service and all transmission BES Elements are in their normal operating state when calculating the system impedance.
3. Saturated (transient or sub-transient) reactance is used for all machines.
4. Both the sending-end and receiving-end voltages at 1.05 per unit.

Guidelines and Technical Basis

Introduction

The NERC System Protection and Control Subcommittee technical document, *Protection System Response to Power Swings*, August 2013,[5] ("PSRPS Report" or "report") was specifically prepared to support the development of this NERC Reliability Standard. The report provided a historical perspective on power swings as early as 1965 up through the approval of the report by the NERC Planning Committee. The report also addresses reliability issues regarding trade-offs between security and dependability of Protection Systems, considerations for this NERC Reliability Standard, and a collection of technical information about power swing characteristics and varying issues with practical applications and approaches to power swings. Of these topics, the report suggests an approach for this NERC Reliability Standard ("standard" or "PRC-026-1") which is consistent with addressing three regulatory directives in the FERC Order No. 733. The first directive concerns the need for "…protective relay systems that differentiate between faults and stable power swings and, when necessary, phases out protective relay systems that cannot meet this requirement."[6] Second, is "…to develop a Reliability Standard addressing undesirable relay operation due to stable power swings."[7] The third directive "…to consider "islanding" strategies that achieve the fundamental performance for all islands in developing the new Reliability Standard addressing stable power swings"[8] was considered during development of the standard.

The development of this standard implements the majority of the approaches suggested by the report. However, it is noted that the Reliability Coordinator and Transmission Planner have not been included in the standard's Applicability section (as suggested by the PSRPS Report). This is so that a single entity, the Planning Coordinator, may be the single source for identifying Elements according to Requirement R1. A single source will insure that multiple entities will not identify Elements in duplicate, nor will one entity fail to provide an Element because it believes the Element is being provided by another entity. The Planning Coordinator has, or has access to, the wide-area model and can correctly identify the Elements that may be susceptible to a stable or unstable power swing. Additionally, not including the Reliability Coordinator and Transmission Planner is consistent with the applicability of other relay loadability NERC Reliability Standards (e.g., PRC-023 and PRC-025). It is also consistent with the NERC Functional Model.

The phrase, "while maintaining dependable fault detection and dependable out-of-step tripping" in Requirement R3, describes that the Generator Owner and Transmission Owner are 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

[5] NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

[6] Transmission Relay Loadability Reliability Standard, Order No. 733, P.150 FERC ¶ 61,221 (2010).

[7] Ibid. P.153.

[8] Ibid. P.162.

this standard is not intended to result in the loss of these protection functions. Instead, the Generator Owner and Transmission Owner must consider both the Requirements within this standard and its desired protection goals and perform modifications to its protective relays or protection philosophies as necessary to achieve both.

Power Swings

The IEEE Power System Relaying Committee WG D6 developed a technical document called *Power Swing and Out-of-Step Considerations on Transmission Lines* (July 2005) that provides background on power swings. The following are general definitions from that document:[9]

> Power Swing: a variation in three phase power flow which occurs when the generator rotor angles are advancing or retarding relative to each other in response to changes in load magnitude and direction, line switching, loss of generation, faults, and other system disturbances.
>
> Pole Slip: a condition whereby a generator, or group of generators, terminal voltage angles (or phases) go past 180 degrees with respect to the rest of the connected power system.
>
> Stable Power Swing: a power swing is considered stable if the generators do not slip poles and the system reaches a new state of equilibrium, i.e. an acceptable operating condition.
>
> Unstable Power Swing: a power swing that will result in a generator or group of generators experiencing pole slipping for which some corrective action must be taken.
>
> Out-of-Step Condition: Same as an unstable power swing.
>
> Electrical System Center or Voltage Zero: it is the point or points in the system where the voltage becomes zero during an unstable power swing.

Burden to Entities

The PSRPS Report provides a technical basis and approach for focusing on Protection Systems, which are susceptible to power swings, while achieving the purpose of the standard. The approach reduces the number of relays to which the PRC-026-1 Requirements would apply by first identifying the BES Element(s) on which load-responsive protective relays must be evaluated. The first step uses criteria to identify the Elements on which a Protection System is expected to be challenged by power swings. Of those Elements, the second step is to evaluate each load-responsive protective relay that is applied on each identified Element. Rather than requiring the Planning Coordinator or Transmission Planner to perform simulations to obtain information for each identified Element, the Generator Owner and Transmission Owner will reduce the need for simulation by comparing the load-responsive protective relay characteristic to specific criteria in PRC-026-1 – Attachment B.

[9] http://www.pes-psrc.org/Reports/Power%20Swing%20and%20OOS%20Considerations%20on%20Transmission%20Lines%20F..pdf.

Applicability

The standard is applicable to the Generator Owner, Planning Coordinator, and Transmission Owner entities. More specifically, the Generator Owner and Transmission Owner entities are applicable when applying load-responsive protective relays at the terminals of the applicable BES Elements. The standard is applicable to the following BES Elements: generators, transformers, and transmission lines. The Distribution Provider was considered for inclusion in the standard; however, it is not subject to the standard because this entity, by functional registration, would not own generators, transmission lines, or transformers other than load serving.

Load-responsive protective relays include any protective functions which could trip with or without time delay, on load current.

Requirement R1

The Planning Coordinator has a wide-area view and is in the position to identify what, if any, Elements meet the criteria. The criterion-based approach is consistent with the NERC System Protection and Control Subcommittee (SPCS) technical document, *Protection System Response to Power Swings (*August 2013),[10] which recommends a focused approach to determine an at-risk Element. Identification of Elements comes from the annual Planning Assessments pursuant to the transmission planning (i.e., "TPL") and other NERC Reliability Standards (e.g., PRC-006), and the standard is not requiring any other assessments to be performed by the Planning Coordinator. The required notification on a calendar year basis to the respective Generator Owner and Transmission Owner is sufficient because it is expected that the Planning Coordinator will make its notifications following the completion of its annual Planning Assessments. The Planning Coordinator will continue to provide notification of Elements on a calendar year basis even if a study is performed less frequently (e.g., PRC-006 – Automatic Underfrequency Load Shedding, which is five years) and has not changed. It is possible that a Planning Coordinator could utilize studies from a prior year in determining the necessary notifications pursuant to Requirement R1.

Criterion 1

The first criterion involves generator(s) where an angular stability constraint exists that is addressed by limiting the output of a generator or a Remedial Action Scheme (RAS) and those Elements terminating at the Transmission station associated with the generator(s). For example, a scheme to remove generation for specific conditions is implemented for a four-unit generating plant (1,100 MW). Two of the units are 500 MW each; one is connected to the 345 kV system and one is connected to the 230 kV system. The Transmission Owner has two 230 kV transmission lines and one 345 kV transmission line all terminating at the generating facility as well as a 345/230 kV autotransformer. The remaining 100 MW consists of two 50 MW combustion turbine (CT) units connected to four 66 kV transmission lines. The 66 kV transmission lines are not electrically joined to the 345 kV and 230 kV transmission lines at the plant site and are not subject to any generating output limitation or RAS. A stability constraint limits the output of the portion of the

[10] http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

plant affected by the RAS to 700 MW for an outage of the 345 kV transmission line. The RAS trips one of the 500 MW units to maintain stability for a loss of the 345 kV transmission line when the total output from both 500 MW units is above 700 MW. For this example, both 500 MW generating units and the associated generator step-up (GSU) transformers would be identified as Elements meeting this criterion. The 345/230 kV autotransformer, the 345 kV transmission line, and the two 230 kV transmission lines would also be identified as Elements meeting this criterion. The 50 MW combustion turbines and 66 kV transmission lines would not be identified pursuant to Criterion 1 because these Elements are not subject to any generating output limitation or RAS and do not terminate at the Transmission station associated with the generators that are subject to any generating output limitation or RAS.

Criterion 2

The second criterion involves Elements associated with angular instability identified in the Planning Assessments. For example, if Planning Assessments have identified that an angular instability could limit transfer capability on two long parallel 500 kV transmission lines to a maximum of 1,200 MW, and this limitation is based on angular instability resulting from a fault and subsequent loss of one of the two lines, then both lines would be identified as Elements meeting the criterion.

Criterion 3

The third criterion involves Elements that form the boundary of an island within an underfrequency load shedding (UFLS) design assessment. The criterion applies to islands identified based on application of the Planning Coordinator's criteria for identifying islands, where the island is formed by tripping the Elements based on angular instability. The criterion applies if the angular instability is modeled in the UFLS design assessment, or if the boundary is identified "off-line" (i.e., the Elements are selected based on angular instability considerations, but the Elements are tripped in the UFLS design assessment without modeling the initiating angular instability). In cases where an out-of-step condition is detected and tripping is initiated at an alternate location, the criterion applies to the Element on which the power swing is detected. The criterion does not apply to islands identified based on other considerations that do not involve angular instability, such as excessive loading, Planning Coordinator area boundary tie lines, or Balancing Authority boundary tie lines.

Criterion 4

The fourth criterion involves Elements identified in the most recent annual Planning Assessment where relay tripping occurs due to a stable or unstable[11] power swing during a simulated disturbance. The intent is for the Planning Coordinator to include any Element(s) where relay tripping was observed during simulations performed for the most recent annual Planning Assessment associated with the transmission planning TPL-001-4 Reliability Standard. Note that

[11] Refer to the "Justification for Including Unstable Power Swings in the Requirements" section.

relay tripping must be assessed within those annual Planning Assessments per TPL-001-4, R4, Part 4.3.1.3, which indicates that analysis shall include the "Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models." Identifying such Elements according to Criterion 4 and notifying the respective Generator Owner and Transmission Owner will require that the owners of any load-responsive protective relay applied at the terminals of the identified Element evaluate the relay's susceptibility to tripping in response to a stable power swing.

Planning Coordinators have the discretion to determine whether the observed tripping for a power swing in its Planning Assessments occurs for valid contingencies and system conditions. The Planning Coordinator will address tripping that is observed in transient analyses on an individual basis; therefore, the Planning Coordinator is responsible for identifying the Elements based only on simulation results that are determined to be valid.

Due to the nature of how a Planning Assessment is performed, there may be cases where a previously-identified Element is not identified in the most recent annual Planning Assessment. If so, this is acceptable because the Generator Owner and Transmission Owner would have taken action upon the initial notification of the previously identified Element. When an Element is not identified in later Planning Assessments, the risk of load-responsive protective relays tripping in response to a stable power swing during non-Fault conditions would have already been assessed under Requirement R2 and mitigated according to Requirements R3 and R4 where the relays did not meet the PRC-026-1 – Attachment B criteria. According to Requirement R2, the Generator Owner and Transmission Owner are only required to re-evaluate each load-responsive protective relay for an identified Element where the evaluation has not been performed in the last five calendar years.

Although Requirement R1 requires the Planning Coordinator to notify the respective Generator Owner and Transmission Owner of any Elements meeting one or more of the four criteria, it does not preclude the Planning Coordinator from providing additional information, such as apparent impedance characteristics, in advance or upon request, that may be useful in evaluating protective relays. Generator Owners and Transmission Owners are able to complete protective relay evaluations and perform the required actions without additional information. The standard does not include any requirement for the entities to provide information that is already being shared or exchanged between entities for operating needs. While a Requirement has not been included for the exchange of information, entities should recognize that relay performance needs to be measured against the most current information.

Requirement R2

Requirement R2 requires the Generator Owner and Transmission Owner to evaluate its load-responsive protective relays to ensure that they are expected to not trip in response to stable power swings.

The PRC-026-1 – Attachment A lists the applicable load-responsive relays that must be evaluated which include phase distance, phase overcurrent, out-of-step tripping, and loss-of-field relay functions. Phase distance relays could include, but are not limited to, the following:

- Zone elements with instantaneous tripping or intentional time delays of less than 15 cycles
- Phase distance elements used in high-speed communication-aided tripping schemes including:
  - Directional Comparison Blocking (DCB) schemes
  - Directional Comparison Un-Blocking (DCUB) schemes
  - Permissive Overreach Transfer Trip (POTT) schemes
  - Permissive Underreach Transfer Trip (PUTT) schemes

A method is provided within the standard to support consistent evaluation by Generator Owners and Transmission Owners based on specified conditions. Once a Generator Owner or Transmission Owner is notified of Elements pursuant to Requirement R1, it has 12 full calendar months to determine if each Element's load-responsive protective relays meet the PRC-026-1 – Attachment B criteria, if the determination has not been performed in the last five calendar years. Additionally, each Generator Owner and Transmission Owner, that becomes aware of a generator, transformer, or transmission line BES Element that tripped in response to a stable or unstable power swing due to the operation of its protective relays pursuant to Requirement R2, Part 2.2, must perform the same PRC-026-1 – Attachment B criteria determination within 12 full calendar months.

Becoming Aware of an Element That Tripped in Response to a Power Swing

Part 2.2 in Requirement R2 is intended to initiate action by the Generator Owner and Transmission Owner when there is a known stable or unstable power swing and it resulted in the entity's Element tripping. The criterion starts with becoming aware of the event (i.e., power swing) and then any connection with the entity's Element tripping. By doing so, the focus is removed from the entity having to demonstrate that it made a determination whether a power swing was present for every Element trip. The basis for structuring the criterion in this manner is driven by the available ways that a Generator Owner and Transmission Owner could become aware of an Element that tripped in response to a stable or unstable power swing due to the operation of its protective relay(s).

Element trips caused by stable or unstable power swings, though infrequent, would be more common in a larger event. The identification of power swings will be revealed during an analysis of the event. Event analysis where an entity may become aware of a stable or unstable power swing could include internal analysis conducted by the entity, the entity's Protection System review following a trip, or a larger scale analysis by other entities. Event analysis could include involvement by the entity's Regional Entity, and in some cases NERC.

Information Common to Both Generation and Transmission Elements

The PRC-026-1 – Attachment A lists the load-responsive protective relays that are subject to this standard. Generator Owners and Transmission Owners may own load-responsive protective relays (e.g., distance relays) that directly affect generation or transmission BES Elements and will require analysis as a result of Elements being identified by the Planning Coordinator in Requirement R1

or the Generator Owner or Transmission Owner in Requirement R2. For example, distance relays owned by the Transmission Owner may be installed at the high-voltage side of the generator step-up (GSU) transformer (directional toward the generator) providing backup to generation protection. Generator Owners may have distance relays applied to backup transmission protection or backup protection to the GSU transformer. The Generator Owner may have relays installed at the generator terminals or the high-voltage side of the GSU transformer.

Exclusion of Time Based Load-Responsive Protective Relays

The purpose of the standard is "[t]o ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions." Load-responsive, high-speed tripping protective relays pose the highest risk of operating during a power swing. Because of this, high-speed tripping protective relays and relays with a time delay of less than 15 cycles are included in the standard; whereas other relays (i.e., Zones 2 and 3) with a time delay of 15 cycles or greater are excluded. The time delay used for exclusion on some load-responsive protective relays is based on the maximum expected time that load-responsive protective relays would be exposed to a stable power swing with a slow slip rate frequency.

In order to establish a time delay that distinguishes a high-risk load-responsive protective relay from one that has a time delay for tripping (lower-risk), a sample of swing rates were calculated based on a stable power swing entering and leaving the impedance characteristic as shown in Table 1. For a relay impedance characteristic that has a power swing entering and leaving, beginning at 90 degrees with a termination at 120 degrees before exiting the zone, the zone timer must be greater than the calculated time the stable power swing is inside the relay's operating zone to not trip in response to the stable power swing.

Eq. (1)
$$Zone\ timer > 2 \times \left(\frac{(120° - Angle\ of\ entry\ into\ the\ relay\ characteristic) \times 60}{(360 \times Slip\ Rate)}\right)$$

Table 1: Swing Rates

Zone Timer (Cycles)	Slip Rate (Hz)
10	1.00
15	0.67
20	0.50
30	0.33

With a minimum zone timer of 15 cycles, the corresponding slip rate of the system is 0.67 Hz. This represents an approximation of a slow slip rate during a system Disturbance. Longer time delays allow for slower slip rates.

Application to Transmission Elements

Criterion A in PRC-026-1 – Attachment B describes an unstable power swing region that is formed by the union of three shapes in the impedance (R-X) plane. The first shape is a lower loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 0.7 (i.e., E_S / E_R = 0.7 / 1.0 = 0.7). The second shape is an upper loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 1.43 (i.e., E_S / E_R = 1.0 / 0.7 = 1.43). The third shape is a lens that connects the endpoints of the total system impedance together by varying the sending-end and receiving-end system voltages from 0.0 to 1.0 per unit, while maintaining a constant system separation angle across the total system impedance (with the parallel transfer impedance removed—see Figures 1 through 5). The total system impedance is derived from a two-bus equivalent network and is determined by summing the sending-end source impedance, the line impedance (excluding the Thévenin equivalent transfer impedance), and the receiving-end source impedance as shown in Figures 6 and 7. Establishing the total system impedance provides a conservative condition that will maximize the security of the relay against various system conditions. The smallest total system impedance represents a condition where the size of the lens characteristic in the R-X plane is smallest and is a conservative operating point from the standpoint of ensuring a load-responsive protective relay is expected to not trip given a predetermined angular displacement between the sending-end and receiving-end voltages. The smallest total system impedance results when all generation is in service and all transmission BES Elements are modeled in their "normal" system configuration (PRC-026-1 – Attachment B, Criterion A). The parallel transfer impedance is removed to represent a likely condition where parallel Elements may be lost during the disturbance, and the loss of these Elements magnifies the sensitivity of the load-responsive relays on the parallel line by removing the "infeed effect" (i.e., the apparent impedance sensed by the relay is decreased as a result of the loss of the transfer impedance, thus making the relay more likely to trip for a stable power swing—See Figures 13 and 14).

The sending-end and receiving-end source voltages are varied from 0.7 to 1.0 per unit to form the lower and upper loss-of-synchronism circles. The ratio of these two voltages is used in the calculation of the loss-of-synchronism circles, and result in a ratio range from 0.7 to 1.43.

Eq. (2) $$\frac{E_S}{E_R} = \frac{0.7}{1.0} = 0.7$$

Eq. (3): $$\frac{E_S}{E_R} = \frac{1.0}{0.7} = 1.43$$

The internal generator voltage during severe power swings or transmission system fault conditions will be greater than zero due to voltage regulator support. The voltage ratio of 0.7 to 1.43 is chosen to be more conservative than the PRC-023[12] and PRC-025[13] NERC Reliability Standards where a lower bound voltage of 0.85 per unit voltage is used. A ±15% internal generator voltage range was chosen as a conservative voltage range for calculation of the voltage ratio used to calculate the loss-of-synchronism circles. For example, the voltage ratio using these voltages would result in a ratio range from 0.739 to 1.353.

[12] Transmission Relay Loadability

[13] Generator Relay Loadability

Eq. (4) $$\frac{E_S}{E_R} = \frac{0.85}{1.15} = 0.739$$ Eq. (5): $$\frac{E_S}{E_R} = \frac{1.15}{0.85} = 1.353$$

The lower ratio is rounded down to 0.7 to be more conservative, allowing a voltage range of 0.7 to 1.0 per unit to be used for the calculation of the loss-of-synchronism circles.[14]

When the parallel transfer impedance is included in the model, the division of current through the parallel transfer impedance path results in actual measured relay impedances that are larger than those measured when the parallel transfer impedance is removed (i.e., infeed effect), which would make it more likely for an impedance relay element to be completely contained within the unstable power swing region as shown in Figure 11. If the transfer impedance is included in the evaluation, a distance relay element could be deemed as meeting PRC-026-1 – Attachment B criteria and, in fact would be secure, assuming all Elements were in their normal state. In this case, the distance relay element could trip in response to a stable power swing during an actual event if the system was weakened (i.e., a higher transfer impedance) by the loss of a subset of lines that make up the parallel transfer impedance as shown in Figure 10. This could happen because the subset of lines that make up the parallel transfer impedance tripped on unstable swings, contained the initiating fault, and/or were lost due to operation of breaker failure or remote back-up protection schemes.

Table 10 shows the percent size increase of the lens shape as seen by the relay under evaluation when the parallel transfer impedance is included. The parallel transfer impedance has minimal effect on the apparent size of the lens shape as long as the parallel transfer impedance is at least 10 multiples of the parallel line impedance (less than 5% lens shape expansion), therefore, its removal has minimal impact, but results in a slightly more conservative, smaller lens shape. Parallel transfer impedances of 5 multiples of the parallel line impedance or less result in an apparent lens shape size of 10% or greater as seen by the relay. If two parallel lines and a parallel transfer impedance tie the sending-end and receiving-end buses together, the total parallel transfer impedance will be one or less multiples of the parallel line impedance, resulting in an apparent lens shape size of 45% or greater. It is a realistic contingency that the parallel line could be out-of-service, leaving the parallel transfer impedance making up the rest of the system in parallel with the line impedance. Since it is not known exactly which lines making up the parallel transfer impedance will be out of service during a major system disturbance, it is most conservative to assume that all of them are out, leaving just the line under evaluation in service.

Either the saturated transient or sub-transient direct axis reactance may be used for machines in the evaluation because they are smaller than the un-saturated reactances. Since saturated sub-transient generator reactances are smaller than the transient or synchronous reactances, the use of sub-transient reactances will result in a smaller source impedance and a smaller unstable power swing region in the graphical analysis as shown in Figures 8 and 9. Because power swings occur in a time frame where generator transient reactances will be prevalent, it is acceptable to use saturated transient reactances instead of saturated sub-transient reactances. Because some short-

[14] *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, April 2004, Section 6 (The Cascade Stage of the Blackout), p. 94 under "Why the Generators Tripped Off," states, "Some generator undervoltage relays were set to trip at or above 90% voltage. However, a motor stalls out at about 70% voltage and a motor starter contactor drops out around 75%, so if there is a compelling need to protect the turbine from the system the under-voltage trigger point should be no higher than 80%."

circuit models may not include transient reactances, the use of sub-transient reactances is also acceptable because it produces more conservative results. For this reason, either value is acceptable when determining the system source impedances (PRC-026-1 – Attachment B, Criterion A and B, No. 3).

Saturated reactances are used in short-circuit programs that produce the system impedance mentioned above. Planning and stability software generally use un-saturated reactances. Generator models used in transient stability analyses recognize that the extent of the saturation effect depends upon both rotor (field) and stator currents. Accordingly, they derive the effective saturated parameters of the machine at each instant by internal calculation from the specified (constant) unsaturated values of machine reactances and the instantaneous internal flux level. The specific assumptions regarding which inductances are affected by saturation, and the relative effect of that saturation, are different for the various generator models used. Thus, unsaturated values of all machine reactances are used in setting up planning and stability software data, and the appropriate set of open-circuit magnetization curve data is provided for each machine.

Saturated reactance values are smaller than unsaturated reactance values and are used in short-circuit programs owned by the Generator and Transmission Owners. Because of this, saturated reactance values are to be used in the development of the system source impedances.

The source or system equivalent impedances can be obtained by a number of different methods using commercially available short-circuit calculation tools.[15] Most short-circuit tools have a network reduction feature that allows the user to select the local and remote terminal buses to retain. The first method reduces the system to one that contains two buses, an equivalent generator at each bus (representing the source impedances at the sending-end and receiving-end), and two parallel lines; one being the line impedance of the protected line with relays being analyzed, the other being the parallel transfer impedance representing all other combinations of lines that connect the two buses together as shown in Figure 6. Another conservative method is to open both ends of the line being evaluated, and apply a three-phase bolted fault at each bus to determine the Thévenin equivalent impedance at each bus. The source impedances are set equal to the Thévenin equivalent impedances and will be less than or equal to the actual source impedances calculated by the network reduction method. Either method can be used to develop the system source impedances at both ends.

The two bullets of PRC-026-1 – Attachment B, Criterion A, No. 1, identify the system separation angles used to identify the size of the power swing stability boundary for evaluating load-responsive protective relay impedance elements. The first bullet of PRC-026-1 – Attachment B, Criterion A, No. 1 evaluates a system separation angle of at least 120 degrees that is held constant while varying the sending-end and receiving-end source voltages from 0.7 to 1.0 per unit, thus creating an unstable power swing region about the total system impedance in Figure 1. This unstable power swing region is compared to the tripping portion of the distance relay characteristic; that is, the portion that is not supervised by load encroachment, blinders, or some other form of supervision as shown in Figure 12 that restricts the distance element from tripping

[15] Demetrios A. Tziouvaras and Daqing Hou, Appendix in *Out-Of-Step Protection Fundamentals and Advancements,* April 17, 2014: https://www.selinc.com.

for heavy, balanced load conditions. If the tripping portion of the impedance characteristics are completely contained within the unstable power swing region, the relay impedance element meets Criterion A in PRC-026-1 – Attachment B. A system separation angle of 120 degrees was chosen for the evaluation because it is generally accepted in the industry that recovery for a swing beyond this angle is unlikely to occur.[16]

The second bullet of PRC-026-1 – Attachment B, Criterion A, No. 1 evaluates impedance relay elements at a system separation angle of less than 120 degrees, similar to the first bullet described above. An angle less than 120 degrees may be used if a documented stability analysis demonstrates that the power swing becomes unstable at a system separation angle of less than 120 degrees.

The exclusion of relay elements supervised by Power Swing Blocking (PSB) in PRC-026-1 – Attachment A allows the Generator Owner or Transmission Owner to exclude protective relay elements if they are blocked from tripping by PSB relays. A PSB relay applied and set according to industry accepted practices prevent supervised load-responsive protective relays from tripping in response to power swings. Further, PSB relays are set to allow dependable tripping of supervised elements. The criteria in PRC-026-1 – Attachment B specifically applies to unsupervised elements that could trip for stable power swings. Therefore, load-responsive protective relay elements supervised by PSB can be excluded from the Requirements of this standard.

[16] "The critical angle for maintaining stability will vary depending on the contingency and the system condition at the time the contingency occurs; however, the likelihood of recovering from a swing that exceeds 120 degrees is marginal and 120 degrees is generally accepted as an appropriate basis for setting out-of-step protection. Given the importance of separating unstable systems, defining 120 degrees as the critical angle is appropriate to achieve a proper balance between dependable tripping for unstable power swings and secure operation for stable power swings." NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf), p. 28.

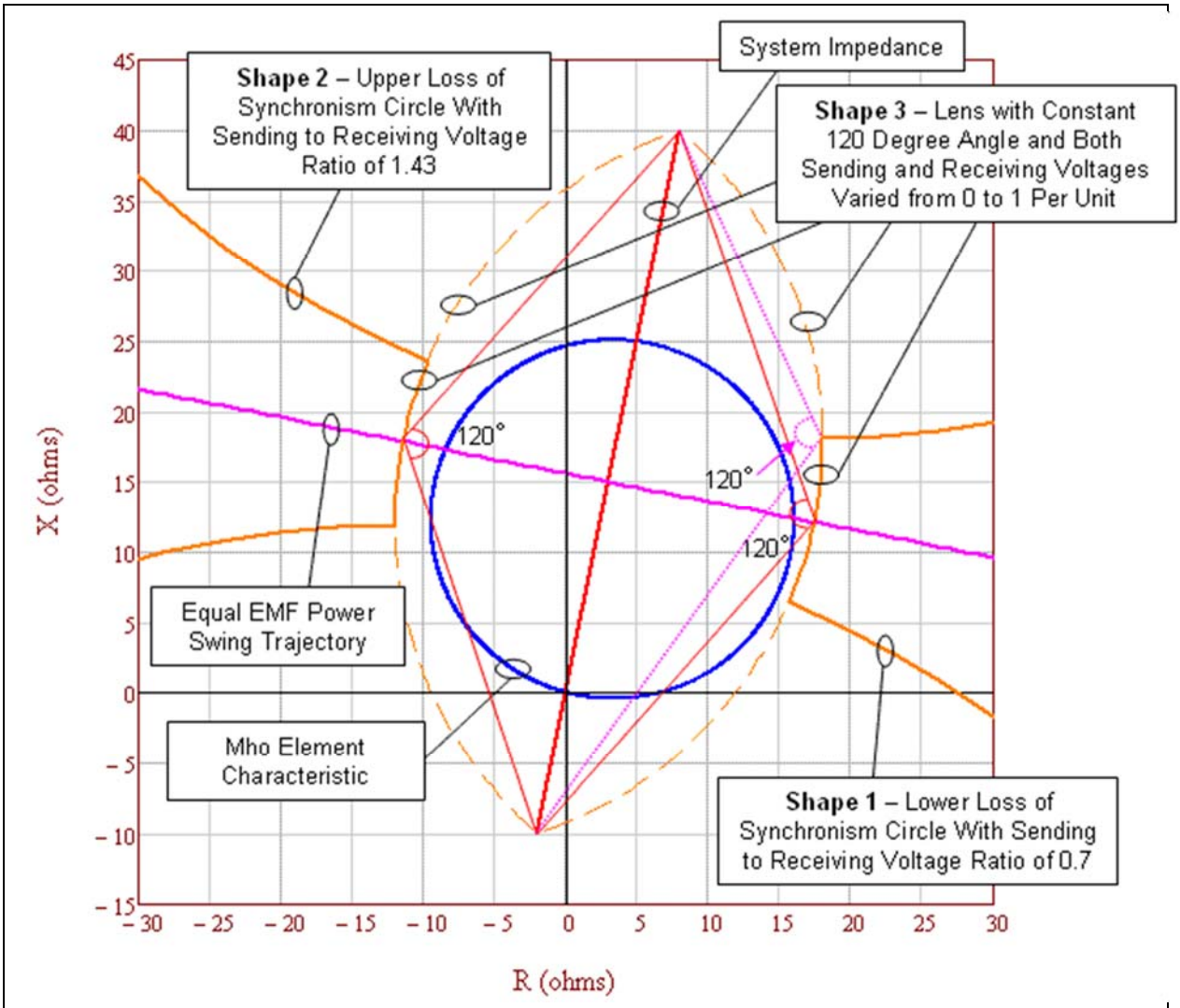

Figure 1: An enlarged graphic illustrating the unstable power swing region formed by the union of three shapes in the impedance (R-X) plane: Shape 1) Lower loss-of-synchronism circle, Shape 2) Upper loss-of-synchronism circle, and Shape 3) Lens. The mho element characteristic is completely contained within the unstable power swing region (i.e., it does not intersect any portion of the unstable power swing region), therefore it meets PRC-026-1 – Attachment B, Criterion A, No. 1.

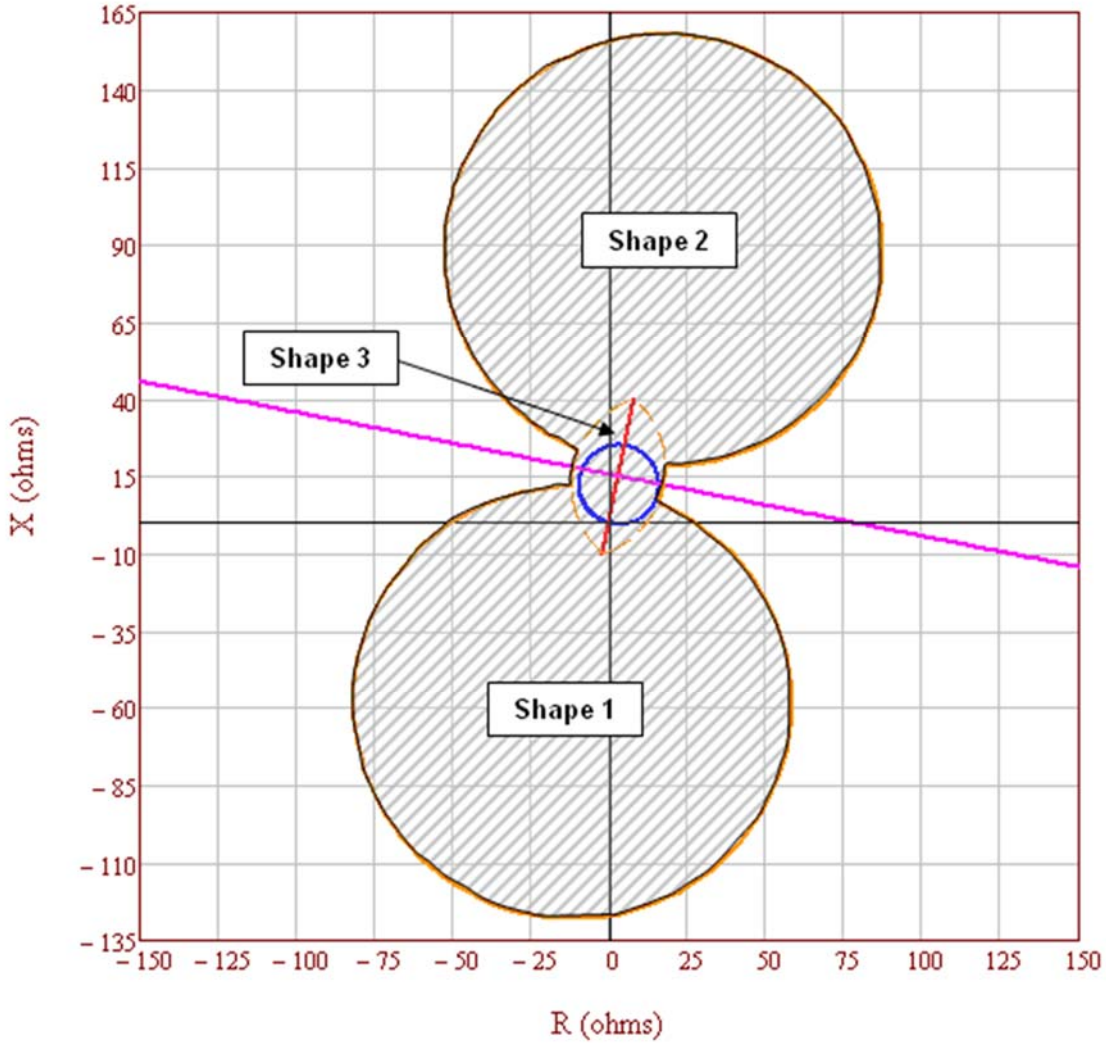

Figure 2: Full graphic of the unstable power swing region formed by the union of the three shapes in the impedance (R-X) plane: Shape 1) Lower loss-of-synchronism circle, Shape 2) Upper loss-of-synchronism circle, and Shape 3) Lens. The mho element characteristic is completely contained within the unstable power swing region, therefore it meets PRC-26-1 – Attachment B, Criterion A, No.1.

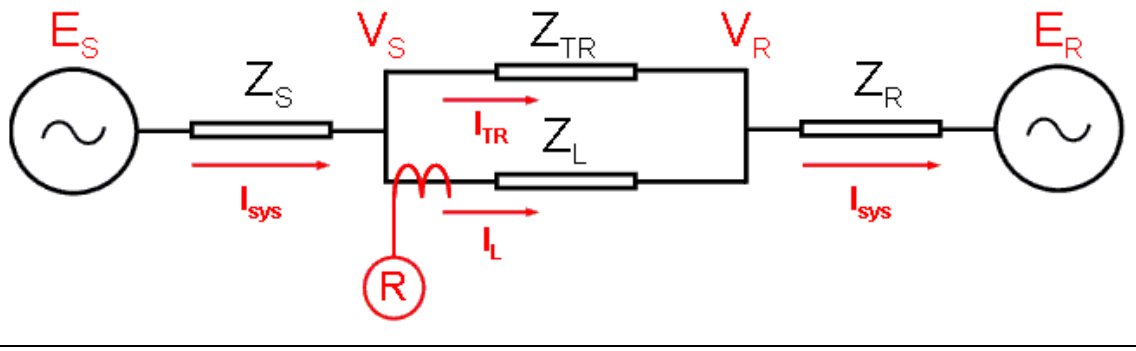

Figure 3: System impedances as seen by Relay R (voltage connections are not shown).

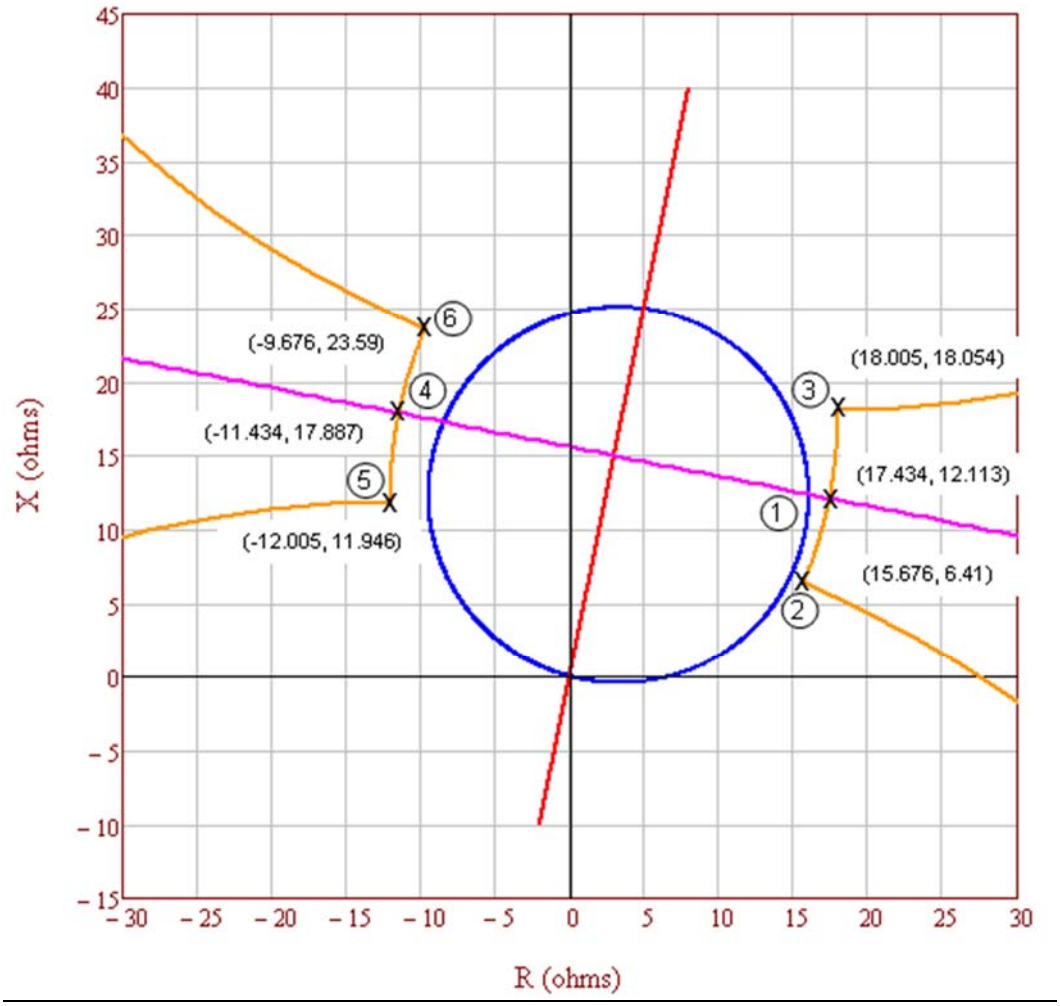

Figure 4: The defining unstable power swing region points where the lens shape intersects the lower and upper loss-of-synchronism circle shapes and where the lens intersects the equal EMF (electromotive force) power swing.

E_S / E_R Voltage Ratio	Left Side Coordinates R	Left Side Coordinates + jX	Right Side Coordinates R	Right Side Coordinates + jX
0.7	**-12.005**	**11.946**	**15.676**	**6.41**
0.72	-12.004	12.407	15.852	6.836
0.74	-11.996	12.857	16.018	7.255
0.76	-11.982	13.298	16.175	7.667
0.78	-11.961	13.729	16.321	8.073
0.8	-11.935	14.151	16.459	8.472
0.82	-11.903	14.563	16.589	8.865
0.84	-11.867	14.966	16.71	9.251
0.86	-11.826	15.361	16.824	9.631
0.88	-11.78	15.746	16.93	10.004
0.9	-11.731	16.123	17.03	10.371
0.92	-11.678	16.492	17.123	10.732
0.94	-11.621	16.852	17.209	11.086
0.96	-11.562	17.205	17.29	11.435
0.98	-11.499	17.55	17.364	11.777
1	**-11.434**	**17.887**	**17.434**	**12.113**
1.0286	-11.336	18.356	17.524	12.584
1.0572	-11.234	18.81	17.604	13.043
1.0858	-11.127	19.251	17.675	13.49
1.1144	-11.017	19.677	17.738	13.926
1.143	-10.904	20.091	17.792	14.351
1.1716	-10.788	20.491	17.84	14.766
1.2002	-10.67	20.88	17.88	15.17
1.2288	-10.55	21.256	17.914	15.564
1.2574	-10.428	21.621	17.942	15.948
1.286	-10.304	21.975	17.964	16.322
1.3146	-10.18	22.319	17.981	16.687
1.3432	-10.054	22.652	17.993	17.043
1.3718	-9.928	22.976	18.001	17.39
1.4004	-9.801	23.29	18.005	17.728
1.429	**-9.676**	**23.59**	**18.005**	**18.054**

Figure 5: Full table of 31 detailed lens shape point calculations. The bold highlighted rows correspond to the detailed calculations in Tables 2-7.

Table 2: Example Calculation (Lens Point 1)	
This example is for calculating the impedance the first point of the lens characteristic. Equal source voltages are used for the 230 kV (base) line with the sending-end voltage (E_S) leading the receiving-end voltage (E_R) by 120 degrees. See Figures 3 and 4.	
Eq. (6)	$E_S = \frac{V_{LL}\angle 120°}{\sqrt{3}}$

Table 2: Example Calculation (Lens Point 1)			
	$E_S = \frac{230{,}000\angle 120°\ V}{\sqrt{3}}$		
	$E_S = 132{,}791\angle 120°\ V$		
Eq. (7)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (8)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (9)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		
Total system current from sending-end source.			
Eq. (10)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \frac{132{,}791\angle 120°\ V - 132{,}791\angle 0°\ V}{(10 + j50\ )\Omega}$		
	$I_{sys} = 4{,}511\angle 71.3°\ A$		
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.			
Eq. (11)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$		

Table 2: Example Calculation (Lens Point 1)	
	$I_L = 4{,}511\angle 71.3° \; A \times \frac{(4 + j20) \times 10^{10} \; \Omega}{(4 + j20) \; \Omega + (4 + j20) \times 10^{10} \; \Omega}$
	$I_L = 4{,}511\angle 71.3° \; A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (12)	$V_S = E_S - (Z_S \times I_{sys})$
	$V_S = 132{,}791\angle 120° \; V - [(2 + j10) \; \Omega \times 4{,}511\angle 71.3° \; A]$
	$V_S = 95{,}757\angle 106.1° \; V$
The impedance seen by the relay on Z_L.	
Eq. (13)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{95{,}757\angle 106.1° \; V}{4{,}511\angle 71.3° \; A}$
	$Z_{L-Relay} = 17.434 + j12.113 \; \Omega$

Table 3: Example Calculation (Lens Point 2)			
This example is for calculating the impedance second point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the sending-end voltage (E_S) at 70% of the receiving-end voltage (E_R) and leading the receiving-end voltage by 120 degrees. See Figures 3 and 4.			
Eq. (14)	$E_S = \frac{V_{LL}\angle 120°}{\sqrt{3}} \times 70\%$		
	$E_S = \frac{230{,}000\angle 120° \; V}{\sqrt{3}} \times 0.70$		
	$E_S = 92{,}953.7\angle 120° \; V$		
Eq. (15)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \frac{230{,}000\angle 0° \; V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0° \; V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10 \; \Omega$	$Z_L = 4 + j20 \; \Omega$	$Z_R = 4 + j20 \; \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10} \; \Omega$		

Table 3: Example Calculation (Lens Point 2)	
Total impedance between the generators.	
Eq. (16)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$
	$Z_{total} = \frac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$
	$Z_{total} = 4 + j20\ \Omega$
Total system impedance.	
Eq. (17)	$Z_{sys} = Z_S + Z_{total} + Z_R$
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$
	$Z_{sys} = 10 + j50\ \Omega$
Total system current from sending-end source.	
Eq. (18)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$
	$I_{sys} = \frac{92{,}953.7\angle 120°\ V - 132{,}791\angle 0°\ V}{(10 + j50)\ \Omega}$
	$I_{sys} = 3{,}854\angle 77°\ A$
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (19)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 77°\ A \times \frac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$
	$I_L = 3{,}854\angle 77°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (20)	$V_S = E_S - \left(Z_S \times I_{sys}\right)$
	$V_S = 92{,}953\angle 120°\ V - [(2 + j10\ )\Omega \times 3{,}854\angle 77°\ A]$
	$V_S = 65{,}271\angle 99°\ V$
The impedance seen by the relay on Z_L.	
Eq. (21)	$Z_{L-Relay} = \frac{V_S}{I_L}$

Table 3: Example Calculation (Lens Point 2)	
	$Z_{L-Relay} = \frac{65{,}271\angle 99° \, V}{3{,}854\angle 77° \, A}$
	$Z_{L-Relay} = 15.676 + j6.41 \, \Omega$

Table 4: Example Calculation (Lens Point 3)			
This example is for calculating the impedance third point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the receiving-end voltage (E_R) at 70% of the sending-end voltage (E_S) and the sending-end voltage leading the receiving-end voltage by 120 degrees. See Figures 3 and 4.			
Eq. (22)	$E_S = \frac{V_{LL}\angle 120°}{\sqrt{3}}$		
	$E_S = \frac{230{,}000\angle 120° \, V}{\sqrt{3}}$		
	$E_S = 132{,}791\angle 120° \, V$		
Eq. (23)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}} \times 70\%$		
	$E_R = \frac{230{,}000\angle 0° \, V}{\sqrt{3}} \times 0.70$		
	$E_R = 92{,}953.7\angle 0° \, V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10 \, \Omega$	$Z_L = 4 + j20 \, \Omega$	$Z_R = 4 + j20 \, \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10} \, \Omega$		
Total impedance between the generators.			
Eq. (24)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{\left((4 + j20) \, \Omega \times (4 + j20) \times 10^{10} \, \Omega\right)}{\left((4 + j20) \, \Omega + (4 + j20) \times 10^{10} \, \Omega\right)}$		
	$Z_{total} = 4 + j20 \, \Omega$		
Total system impedance.			
Eq. (25)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10) \, \Omega + (4 + j20) \, \Omega + (4 + j20) \, \Omega$		
	$Z_{sys} = 10 + j50 \, \Omega$		

Table 4: Example Calculation (Lens Point 3)	
Total system current from sending-end source.	
Eq. (26)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$
	$I_{sys} = \frac{132{,}791\angle 120° \, V - 92{,}953.7\angle 0° \, V}{(10 + j50) \, \Omega}$
	$I_{sys} = 3{,}854\angle 65.5° \, A$
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (27)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 65.5° \, A \times \frac{(4 + j20) \times 10^{10} \, \Omega}{(4 + j20) \, \Omega + (4 + j20) \times 10^{10} \, \Omega}$
	$I_L = 3{,}854\angle 65.5° \, A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (28)	$V_S = E_S - (Z_S \times I_L)$
	$V_S = 132{,}791\angle 120° \, V - [(2 + j10) \, \Omega \times 3{,}854\angle 65.5° \, A]$
	$V_S = 98{,}265\angle 110.6° \, V$
The impedance seen by the relay on Z_L.	
Eq. (29)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{98{,}265\angle 110.6° \, V}{3{,}854\angle 65.5° \, A}$
	$Z_{L-Relay} = 18.005 + j18.054 \, \Omega$

Table 5: Example Calculation (Lens Point 4)	
This example is for calculating the impedance fourth point of the lens characteristic. Equal source voltages are used for the 230 kV (base) line with the sending-end voltage (E_S) leading the receiving-end voltage (E_R) by 240 degrees. See Figures 3 and 4.	
Eq. (30)	$E_S = \frac{V_{LL}\angle 240°}{\sqrt{3}}$
	$E_S = \frac{230{,}000\angle 240° \, V}{\sqrt{3}}$

Table 5: Example Calculation (Lens Point 4)			
	$E_S = 132{,}791\angle 240° \, V$		
Eq. (31)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \frac{230{,}000\angle 0° \, V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0° \, V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10 \, \Omega$	$Z_L = 4 + j20 \, \Omega$	$Z_R = 4 + j20 \, \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10} \, \Omega$		
Total impedance between the generators.			
Eq. (32)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{\left((4 + j20) \, \Omega \times (4 + j20) \times 10^{10} \, \Omega\right)}{\left((4 + j20) \, \Omega + (4 + j20) \times 10^{10} \, \Omega\right)}$		
	$Z_{total} = 4 + j20 \, \Omega$		
Total system impedance.			
Eq. (33)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10) \, \Omega + (4 + j20) \, \Omega + (4 + j20) \, \Omega$		
	$Z_{sys} = 10 + j50 \, \Omega$		
Total system current from sending-end source.			
Eq. (34)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \frac{132{,}791\angle 240° \, V - 132{,}791\angle 0° \, V}{(10 + j50 \,)\Omega}$		
	$I_{sys} = 4{,}511\angle 131.3° \, A$		
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.			
Eq. (35)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$		
	$I_L = 4{,}511\angle 131.1° \, A \times \frac{(4 + j20) \times 10^{10} \, \Omega}{(4 + j20) \, \Omega + (4 + j20) \times 10^{10} \, \Omega}$		
	$I_L = 4{,}511\angle 131.1° \, A$		

Table 5: Example Calculation (Lens Point 4)			
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.			
Eq. (36)	$V_S = E_S - (Z_S \times I_L)$		
	$V_S = 132{,}791\angle 240° \, V - [(2 + j10\,)\,\Omega \times 4{,}511\angle 131.1° \, A]$		
	$V_S = 95{,}756\angle -106.1° \, V$		
The impedance seen by the relay on Z_L.			
Eq. (37)	$Z_{L-Relay} = \frac{V_S}{I_L}$		
	$Z_{L-Relay} = \frac{95{,}756\angle -106.1° \, V}{4{,}511\angle 131.1° \, A}$		
	$Z_{L-Relay} = -11.434 + j17.887\ \Omega$		

Table 6: Example Calculation (Lens Point 5)			
This example is for calculating the impedance fifth point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the sending-end voltage (E_S) at 70% of the receiving-end voltage (E_R) and leading the receiving-end voltage by 240 degrees. See Figures 3 and 4.			
Eq. (38)	$E_S = \frac{V_{LL}\angle 240°}{\sqrt{3}} \times 70\%$		
	$E_S = \frac{230{,}000\angle 240° \, V}{\sqrt{3}} \times 0.70$		
	$E_S = 92{,}953.7\angle 240° \, V$		
Eq. (39)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \frac{230{,}000\angle 0° \, V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0° \, V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (40)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		

Table 6: Example Calculation (Lens Point 5)	
	$Z_{total} = \frac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$
	$Z_{total} = 4 + j20\ \Omega$
Total system impedance.	
Eq. (41)	$Z_{sys} = Z_S + Z_{total} + Z_R$
	$Z_{sys} = (2 + j10\ \Omega) + (4 + j20\ \Omega) + (4 + j20\ \Omega)$
	$Z_{sys} = 10 + j50\ \Omega$
Total system current from sending-end source.	
Eq. (42)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$
	$I_{sys} = \frac{92{,}953.7\angle 240°\ V - 132{,}791\angle 0°\ V}{10 + j50\ \Omega}$
	$I_{sys} = 3{,}854\angle 125.5°\ A$
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (43)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 125.5°\ A \times \frac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$
	$I_L = 3{,}854\angle 125.5°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (44)	$V_S = E_S - (Z_S \times I_L)$
	$V_S = 92{,}953.7\angle 240°\ V - [(2 + j10\ )\ \Omega \times 3{,}854\angle 125.5°\ A]$
	$V_S = 65{,}270.5\angle -99.4°\ V$
The impedance seen by the relay on Z_L.	
Eq. (45)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{65{,}270.5\angle -99.4°\ V}{3{,}854\angle 125.5°\ A}$
	$Z_{L-Relay} = -12.005 + j11.946\ \Omega$

Table 7: Example Calculation (Lens Point 6)			
This example is for calculating the impedance sixth point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the receiving-end voltage (E_R) at 70% of the sending-end voltage (E_S) and the sending-end voltage leading the receiving-end voltage by 240 degrees. See Figures 3 and 4.			
Eq. (46)	$E_S = \frac{V_{LL}\angle 240°}{\sqrt{3}}$		
	$E_S = \frac{230{,}000\angle 240°\ V}{\sqrt{3}}$		
	$E_S = 132{,}791\angle 240°\ V$		
Eq. (47)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}} \times 70\%$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}} \times 0.70$		
	$E_R = 92{,}953.7\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (48)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (49)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		
Total system current from sending-end source.			
Eq. (50)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \frac{132{,}791\angle 240°\ V - 92{,}953.7\angle 0°\ V}{10 + j50\ \Omega}$		
	$I_{sys} = 3{,}854\angle 137.1°\ A$		

Table 7: Example Calculation (Lens Point 6)	
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (51)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 137.1° \, A \times \frac{(4 + j20) \times 10^{10} \, \Omega}{(4 + j20) \, \Omega + (4 + j20) \times 10^{10} \, \Omega}$
	$I_L = 3{,}854\angle 137.1° \, A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (52)	$V_S = E_S - (Z_S \times I_L)$
	$V_S = 132{,}791\angle 240° \, V - [(2 + j10 \,) \, \Omega \times 3{,}854\angle 137.1° \, A]$
	$V_S = 98{,}265\angle -110.6° \, V$
The impedance seen by the relay on Z_L.	
Eq. (53)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{98{,}265\angle -110.6° \, V}{3{,}854\angle 137.1° \, A}$
	$Z_{L-Relay} = -9.676 + j23.59 \, \Omega$

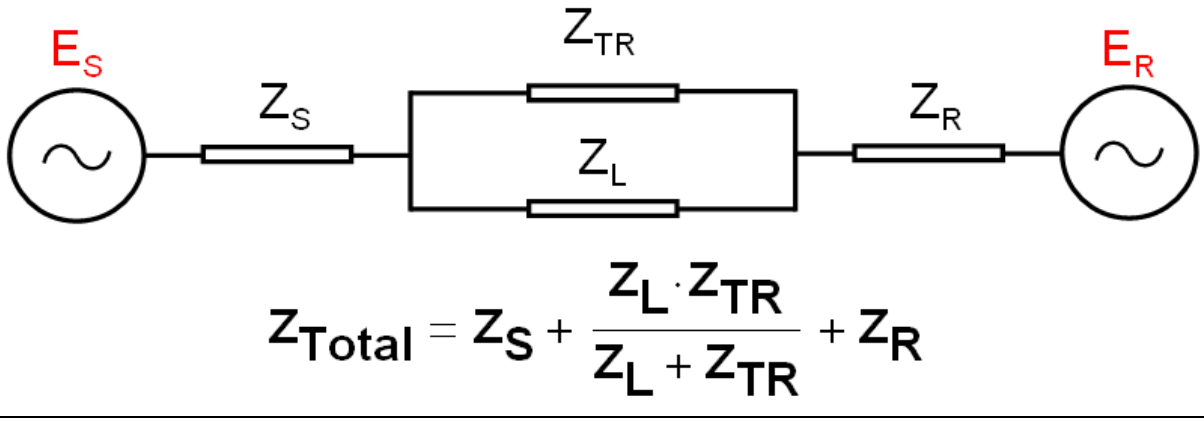

Figure 6: Reduced two bus system with sending-end source impedance Z_S, receiving-end source impedance Z_R, line impedance Z_L, and parallel transfer impedance Z_{TR}.

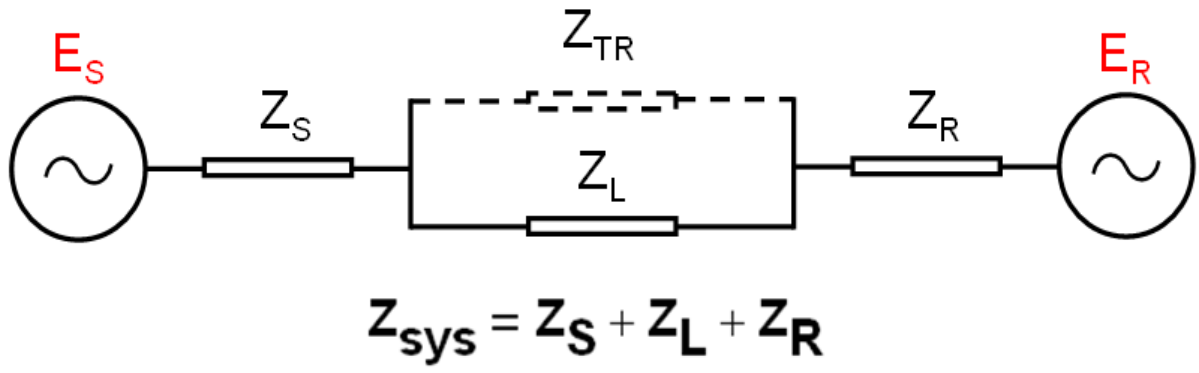

Figure 7: Reduced two bus system with sending-end source impedance Z_S, receiving-end source impedance Z_R, and line impedance Z_L with the parallel transfer impedance Z_{TR} removed.

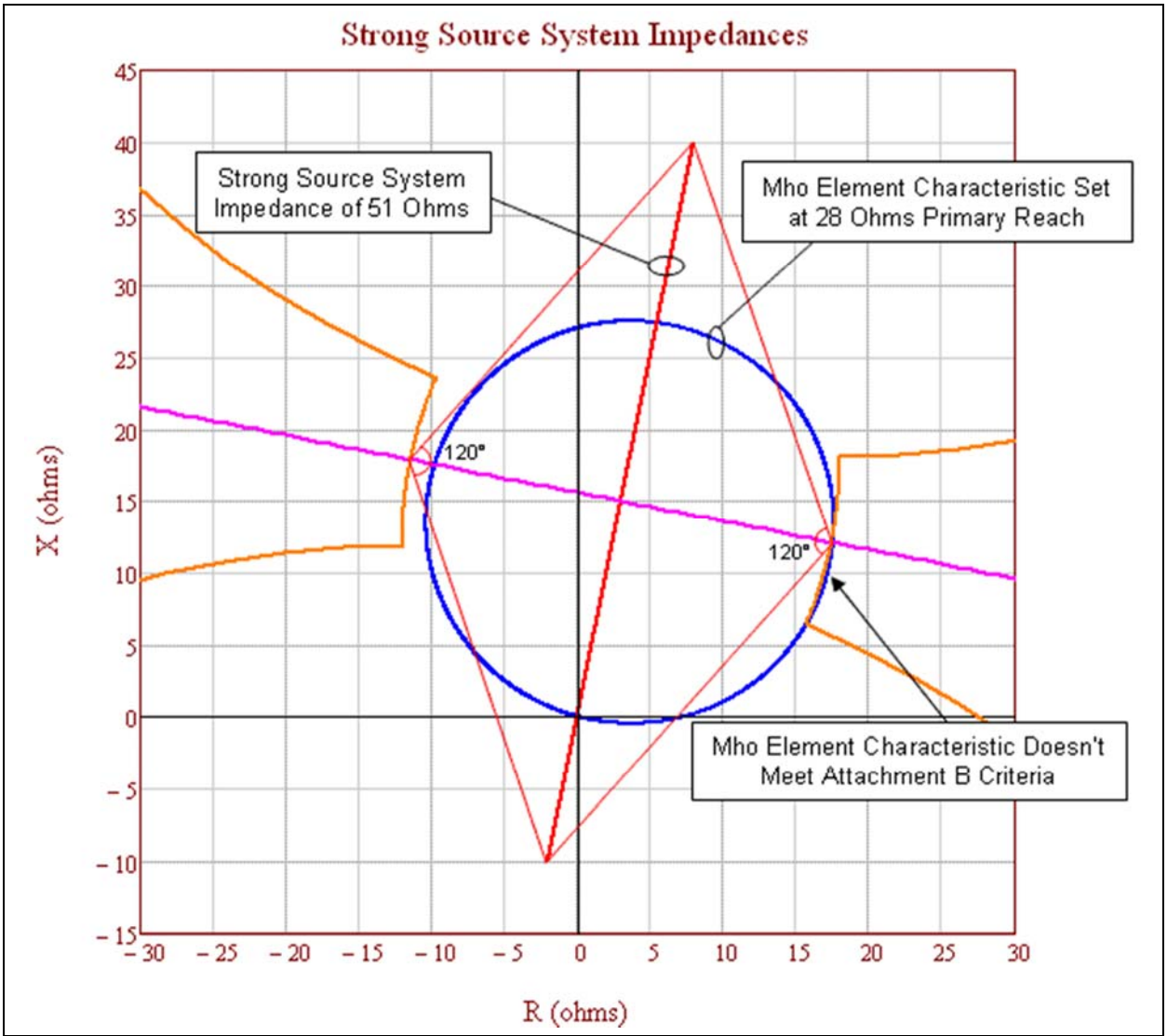

Figure 8: A strong-source system with a line impedance of Z_L = 20.4 ohms (i.e., the thicker red line). This mho element characteristic (i.e., the blue circle) does not meet the PRC-026-1 – Attachment B, Criterion A because it is not completely contained within the unstable power swing region (i.e., the orange characteristic).

Figure 8 above represents a heavily-loaded system with all generation in service and all transmission BES Elements in their normal operating state. The mho element characteristic (set at 137% of Z_L) extends into the unstable power swing region (i.e., the orange characteristic). Using the strongest source system is more conservative because it shrinks the unstable power swing region, bringing it closer to the mho element characteristic. This figure also graphically represents the effect of a system strengthening over time and this is the reason for re-evaluation if the relay has not been evaluated in the last five calendar years. Figure 9 below depicts a relay that meets the PRC-026-1 – Attachment B, Criterion A. Figure 8 depicts the same relay with the same setting five years later, where each source has strengthened by about 10% and now the same mho element characteristic does not meet Criterion A.

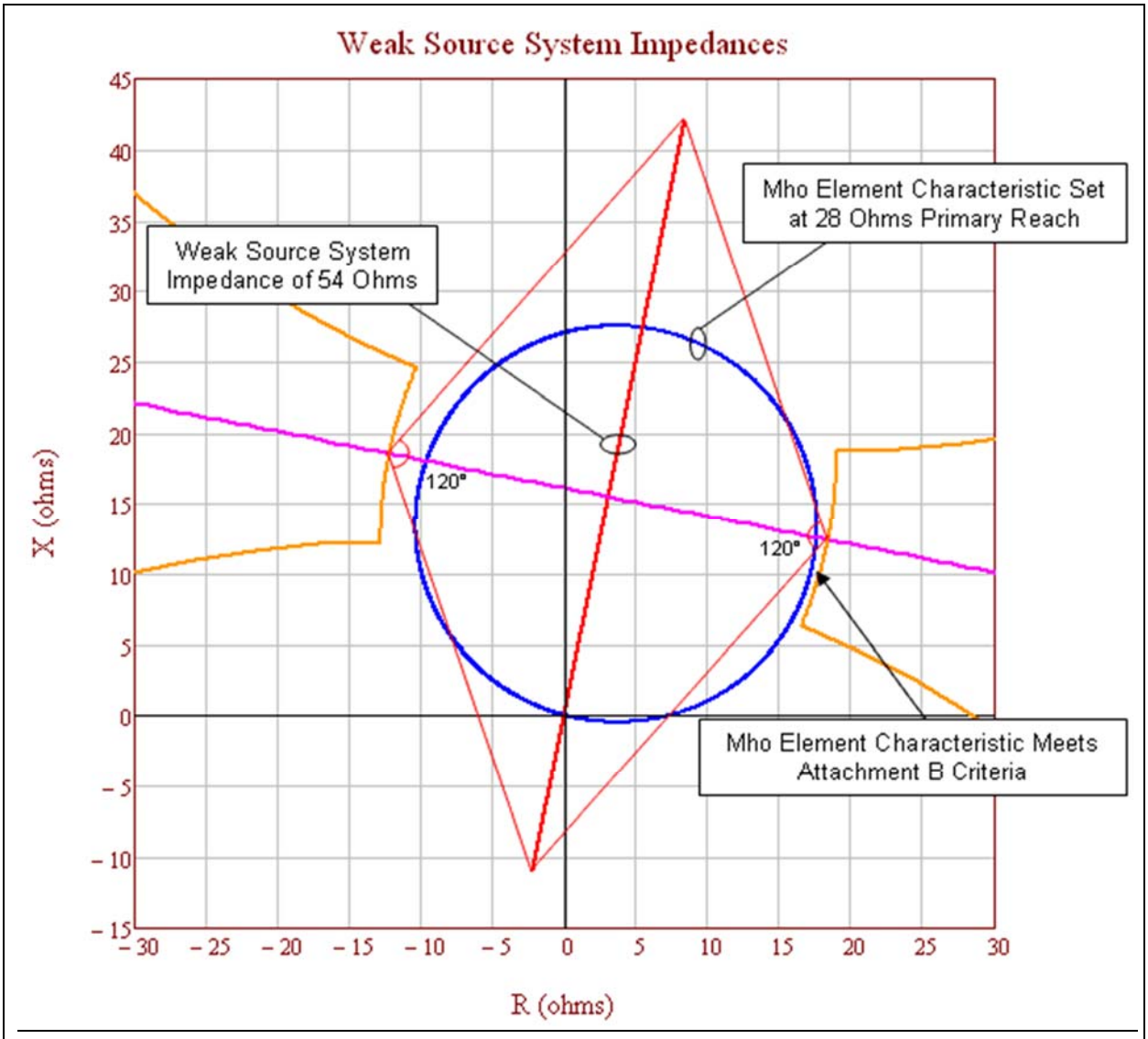

Figure 9: A weak-source system with a line impedance of Z_L = 20.4 ohms (i.e., the thicker red line). This mho element characteristic (i.e., the blue circle) meets the PRC-026-1 – Attachment B, Criterion A because it is completely contained within the unstable power swing region (i.e., the orange characteristic).

Figure 9 above represents a lightly-loaded system, using a minimum generation profile. The mho element characteristic (set at 137% of Z_L) does not extend into the unstable power swing region (i.e., the orange characteristic). Using a weaker source system expands the unstable power swing region away from the mho element characteristic.

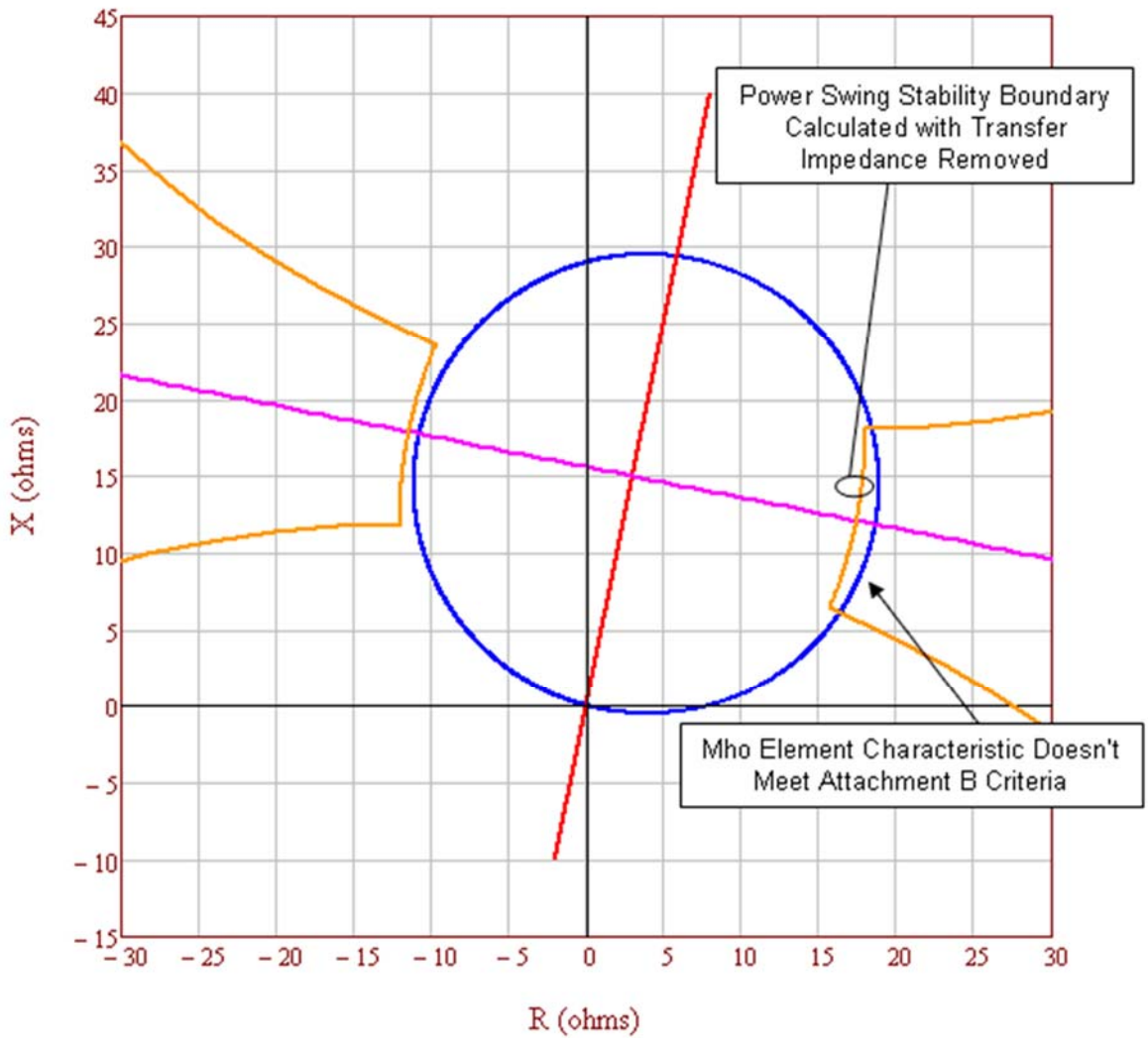

Figure 10: This is an example of an unstable power swing region (i.e., the orange characteristic) with the parallel transfer impedance removed. This relay mho element characteristic (i.e., the blue circle) does not meet PRC-026-1 – Attachment B, Criterion A because it is not completely contained within the unstable power swing region.

Table 8: Example Calculation (Parallel Transfer Impedance Removed)	
Calculations for the point at 120 degrees with equal source impedances. The total system current equals the line current. See Figure 10.	
Eq. (54)	$E_S = \frac{V_{LL}\angle 120°}{\sqrt{3}}$
	$E_S = \frac{230{,}000\angle 120°\ V}{\sqrt{3}}$
	$E_S = 132{,}791\angle 120°\ V$

Table 8: Example Calculation (Parallel Transfer Impedance Removed)			
Eq. (55)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Given impedance data.			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (56)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (57)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		
Total system current from sending-end source.			
Eq. (58)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \frac{132{,}791\angle 120°\ V - 132{,}791\angle 0°\ V}{10 + j50\ \Omega}$		
	$I_{sys} = 4{,}511\angle 71.3°\ A$		
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.			
Eq. (59)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$		
	$I_L = 4{,}511\angle 71.3°\ A \times \frac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$		
	$I_L = 4{,}511\angle 71.3°\ A$		

Table 8: Example Calculation (Parallel Transfer Impedance Removed)	
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (60)	$V_S = E_S - \left(Z_S \times I_{sys}\right)$
	$V_S = 132{,}791\angle 120° \, V - [(2 + j10\ \Omega) \times 4{,}511\angle 71.3° \, A]$
	$V_S = 95{,}757\angle 106.1° \, V$
The impedance seen by the relay on Z_L.	
Eq. (61)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{95{,}757\angle 106.1° \, V}{4{,}511\angle 71.3° \, A}$
	$Z_{L-Relay} = 17.434 + j12.113\ \Omega$

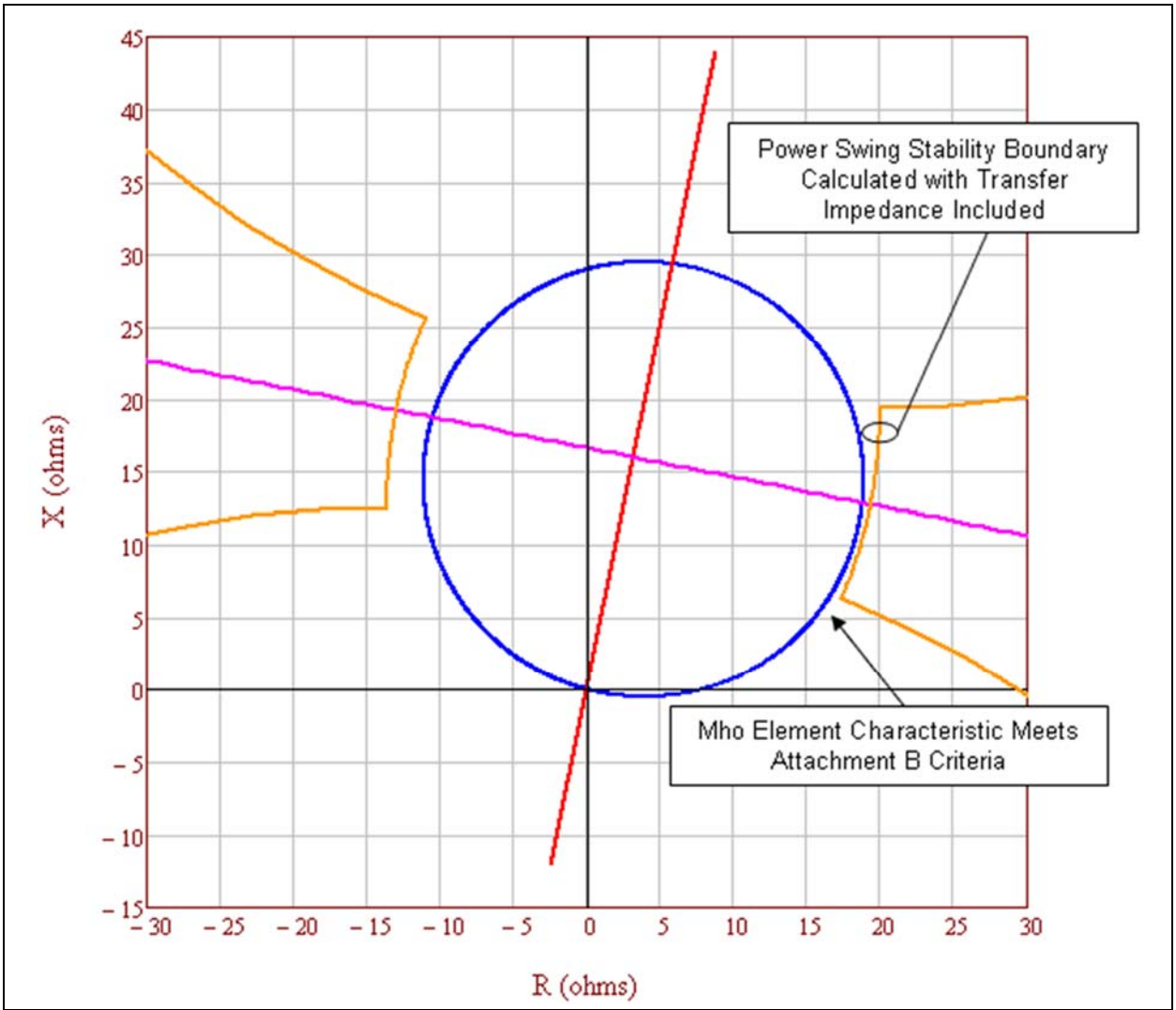

Figure 11: This is an example of an unstable power swing region (i.e., the orange characteristic) with the parallel transfer impedance included causing the mho element characteristic (i.e., the blue circle) to appear to meet the PRC-026-1 – Attachment B, Criterion A because it is completely contained within the unstable power swing region. Including the parallel transfer impedance in the calculation is not allowed by the PRC-026-1 – Attachment B, Criterion A.

In Figure 11 above, the parallel transfer impedance is 5 times the line impedance. The unstable power swing region has expanded out beyond the mho element characteristic due to the infeed effect from the parallel current through the parallel transfer impedance, thus allowing the mho element characteristic to appear to meet the PRC-026-1 – Attachment B, Criterion A. Including the parallel transfer impedance in the calculation is not allowed by the PRC-026-1 – Attachment B, Criterion A.

Table 9: Example Calculation (Parallel Transfer Impedance Included)			
Calculations for the point at 120 degrees with equal source impedances. The total system current does not equal the line current. See Figure 11.			
Eq. (62)	$E_S = \frac{V_{LL}\angle 120°}{\sqrt{3}}$		
	$E_S = \frac{230{,}000\angle 120°\ V}{\sqrt{3}}$		
	$E_S = 132{,}791\angle 120°\ V$		
Eq. (63)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Given impedance data.			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 5$		
	$Z_{TR} = (4 + j20)\ \Omega \times 5$		
	$Z_{TR} = 20 + j100\ \Omega$		
Total impedance between the generators.			
Eq. (64)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{(4 + j20)\ \Omega \times (20 + j100)\ \Omega}{(4 + j20)\ \Omega + (20 + j100)\ \Omega}$		
	$Z_{total} = 3.333 + j16.667\ \Omega$		
Total system impedance.			
Eq. (65)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (3.333 + j16.667)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 9.333 + j46.667\ \Omega$		
Total system current from sending-end source.			
Eq. (66)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \frac{132{,}791\angle 120°\ V - 132{,}791\angle 0°\ V}{9.333 + j46.667\ \Omega}$		

Table 9: Example Calculation (Parallel Transfer Impedance Included)	
	$I_{sys} = 4{,}833\angle 71.3° \; A$
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (67)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 4{,}833\angle 71.3° \; A \times \frac{(20 + j100)\;\Omega}{(4 + j20)\;\Omega + (20 + j100)\;\Omega}$
	$I_L = 4{,}027.4\angle 71.3° \; A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (68)	$V_S = E_S - (Z_S \times I_{sys})$
	$V_S = 132{,}791\angle 120° \; V - [(2 + j10\;\Omega) \times 4{,}833\angle 71.3° \; A]$
	$V_S = 93{,}417\angle 104.7° \; V$
The impedance seen by the relay on Z_L.	
Eq. (69)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{93{,}417\angle 104.7° \; V}{4{,}027\angle 71.3° \; A}$
	$Z_{L-Relay} = 19.366 + j12.767\;\Omega$

Table 10: Percent Increase of a Lens Due To Parallel Transfer Impedance.	
The following demonstrates the percent size increase of the lens characteristic for Z_{TR} in multiples of Z_L with the parallel transfer impedance included.	
Z_{TR} in multiples of Z_L	Percent increase of lens with equal EMF sources (Infinite source as reference)
Infinite	N/A
1000	0.05%
100	0.46%
10	4.63%
5	9.27%
2	23.26%
1	46.76%
0.5	94.14%
0.25	189.56%

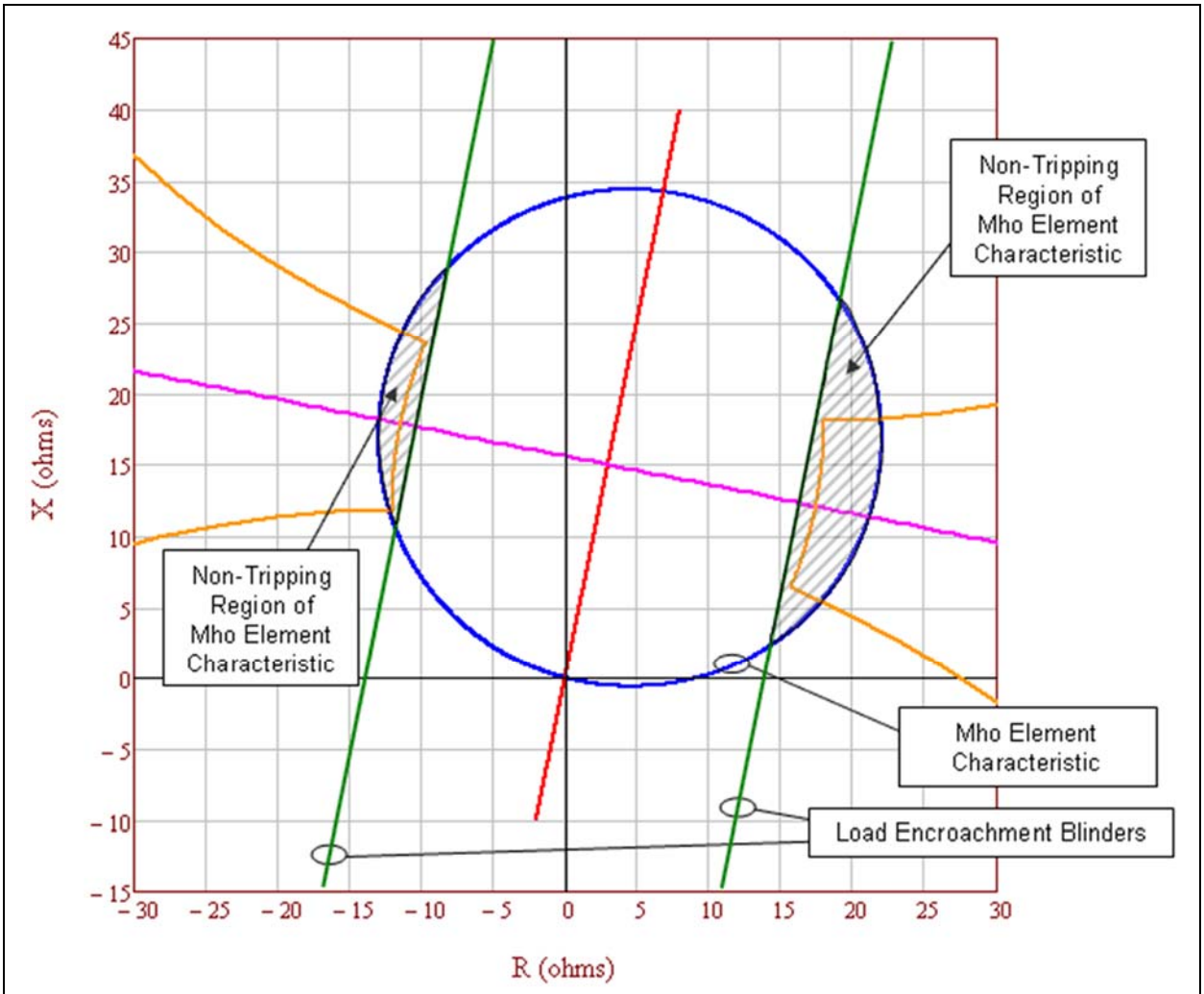

Figure 12: The tripping portion of the mho element characteristic (i.e., the blue circle) not blocked by load encroachment (i.e., the parallel green lines) is completely contained within the unstable power swing region (i.e., the orange characteristic). Therefore, the mho element characteristic meets the PRC-026-1 – Attachment B, Criterion A.

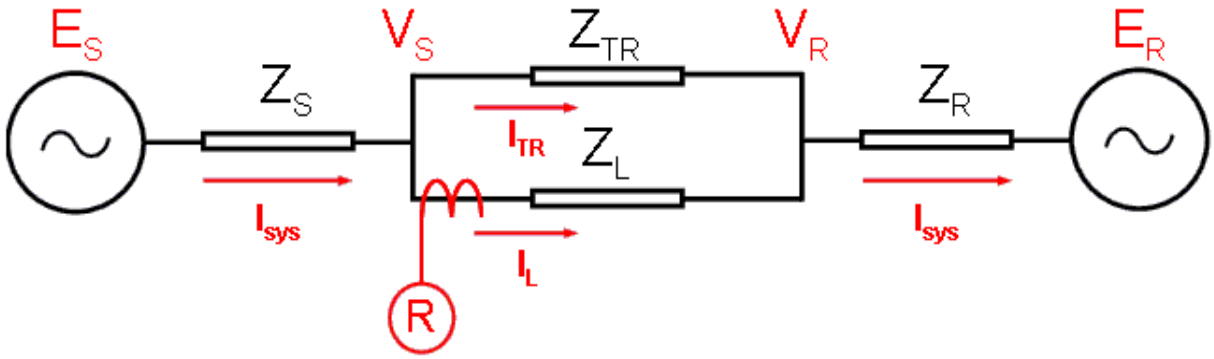

Figure 13: The infeed diagram shows the impedance in front of the relay R with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the forward direction becomes $Z_L + Z_R$.

Table 11: Calculations (System Apparent Impedance in the forward direction)				
The following equations are provided for calculating the apparent impedance back to the E_R source voltage as seen by relay R. Infeed equations from V_S to source E_R where $E_R = 0$. See Figure 13.				
Eq. (70)	$I_L = \frac{V_S - V_R}{Z_L}$			
Eq. (71)	$I_{sys} = \frac{V_R - E_R}{Z_R}$			
Eq. (72)	$I_{sys} = I_L + I_{TR}$			
Eq. (73)	$I_{sys} = \frac{V_R}{Z_R}$	Since $E_R = 0$	Rearranged:	$V_R = I_{sys} \times Z_R$
Eq. (74)	$I_L = \frac{V_S - I_{sys} \times Z_R}{Z_L}$			
Eq. (75)	$I_L = \frac{V_S - [(I_L + I_{TR}) \times Z_R]}{Z_L}$			
Eq. (76)	$V_S = (I_L \times Z_L) + (I_L \times Z_R) + (I_{TR} \times Z_R)$			
Eq. (77)	$Z_{Relay} = \frac{V_S}{I_L} = Z_L + Z_R + \frac{I_{TR} \times Z_R}{I_L} = Z_L + Z_R \times \left(1 + \frac{I_{TR}}{I_L}\right)$			
Eq. (78)	$I_{TR} = I_{sys} \times \frac{Z_L}{Z_L + Z_{TR}}$			
Eq. (79)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$			

Table 11: Calculations (System Apparent Impedance in the forward direction)	
Eq. (80)	$\frac{I_{TR}}{I_L} = \frac{Z_L}{Z_{TR}}$
The infeed equations shows the impedance in front of the relay R (Figure 13) with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the forward direction becomes $Z_L + Z_R$.	
Eq. (81)	$Z_{Relay} = Z_L + Z_R \times \left(1 + \frac{Z_L}{Z_{TR}}\right)$

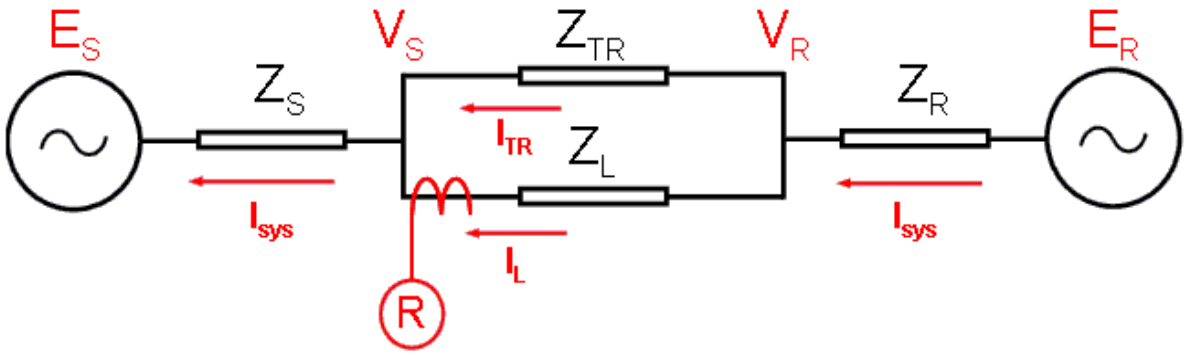

Figure 14: The infeed diagram shows the impedance behind relay R with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the reverse direction becomes Z_S.

Table 12: Calculations (System Apparent Impedance in the Reverse Direction)				
The following equations are provided for calculating the apparent impedance back to the E_S source voltage as seen by relay R. Infeed equations from V_R back to source E_S where $E_S = 0$. See Figure 14.				
Eq. (82)	$I_L = \frac{V_R - V_S}{Z_L}$			
Eq. (83)	$I_{sys} = \frac{V_S - E_S}{Z_S}$			
Eq. (84)	$I_{sys} = I_L + I_{TR}$			
Eq. (85)	$I_{sys} = \frac{V_S}{Z_S}$	Since $E_s = 0$	Rearranged:	$V_S = I_{sys} \times Z_S$
Eq. (86)	$I_L = \frac{V_R - I_{sys} \times Z_S}{Z_L}$			

Table 12: Calculations (System Apparent Impedance in the Reverse Direction)		
Eq. (87)	$I_L = \frac{V_R - [(I_L + I_{TR}) \times Z_S]}{Z_L}$	
Eq. (88)	$V_R = (I_L \times Z_L) + (I_L \times Z_S) + (I_{TR} \times Z_{RS})$	
Eq. (89)	$Z_{Relay} = \frac{V_R}{I_L} = Z_L + Z_S + \frac{I_{TR} \times Z_S}{I_L} = Z_L + Z_S \times \left(1 + \frac{I_{TR}}{I_L}\right)$	
Eq. (90)	$I_{TR} = I_{sys} \times \frac{Z_L}{Z_L + Z_{TR}}$	
Eq. (91)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$	
Eq. (92)	$\frac{I_{TR}}{I_L} = \frac{Z_L}{Z_{TR}}$	
The infeed equations shows the impedance behind relay R (Figure 14) with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the reverse direction becomes Z_S.		
Eq. (93)	$Z_{Relay} = Z_L + Z_S \times \left(1 + \frac{Z_L}{Z_{TR}}\right)$	As seen by relay R at the receiving-end of the line.
Eq. (94)	$Z_{Relay} = Z_S \times \left(1 + \frac{Z_L}{Z_{TR}}\right)$	Subtract Z_L for relay R impedance as seen at sending-end of the line.

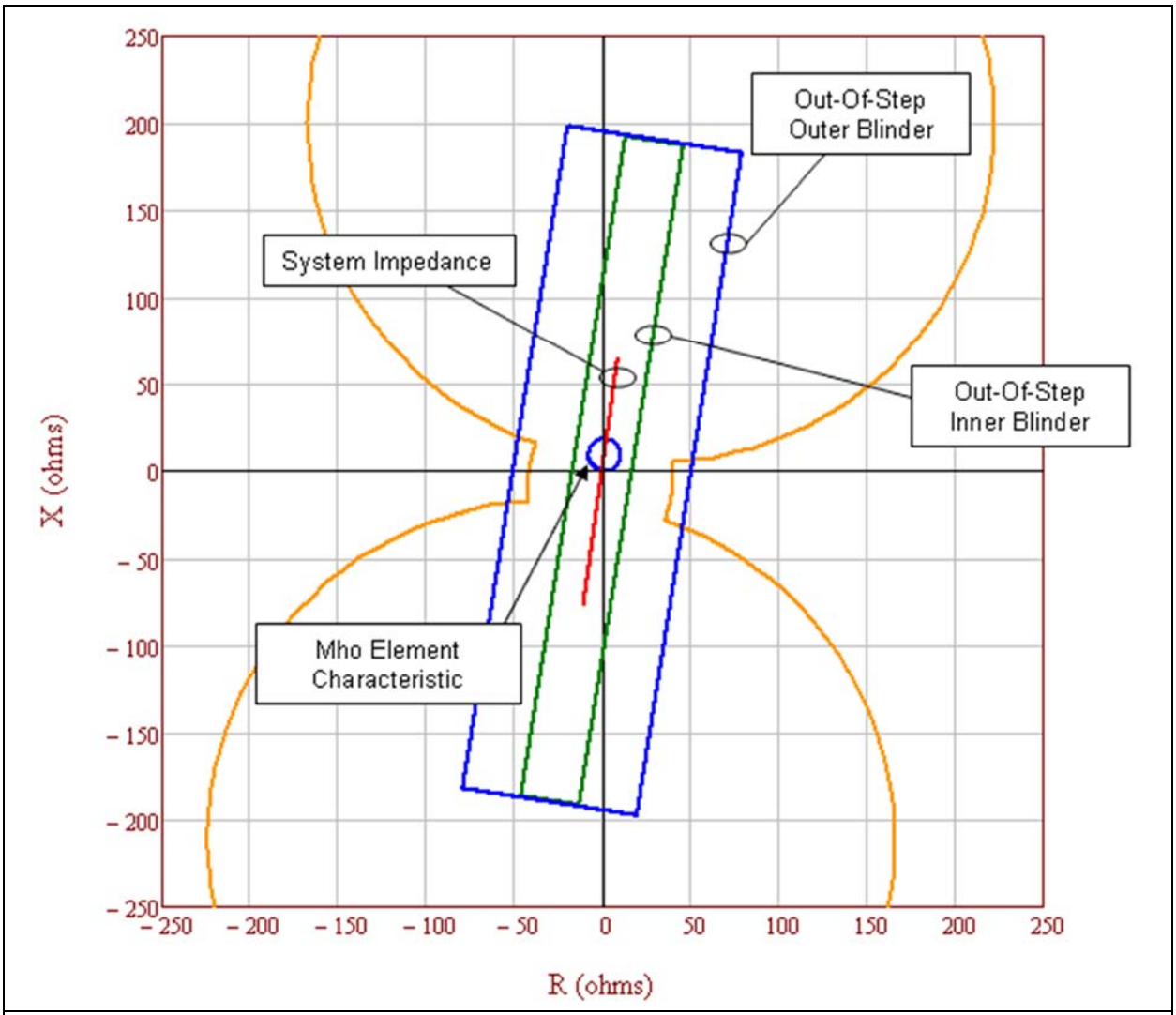

Figure 15: Out-of-step trip (OST) inner blinder (i.e., the parallel green lines) meets the PRC-026-1 – Attachment B, Criterion A because the inner OST blinder initiates tripping either On-The-Way-In or On-The-Way-Out. Since the inner blinder is completely contained within the unstable power swing region (i.e., the orange characteristic), it meets the PRC-026-1 – Attachment B, Criterion A.

Table 13: Example Calculation (Voltage Ratios)			
These calculations are based on the loss-of-synchronism characteristics for the cases of N < 1 and N > 1 as found in the *Application of Out-of-Step Blocking and Tripping Relays*, GER-3180, p. 12, Figure 3.[17] The GE illustration shows the formulae used to calculate the radius and center of the circles that make up the ends of the portion of the lens.			
Voltage ratio equations, source impedance equation with infeed formulae applied, and circle equations.			
Given:	$E_S = 0.7$	$E_R = 1.0$	
Eq. (95)	$N = \frac{\lvert E_S \rvert}{\lvert E_R \rvert} = \frac{0.7}{1.0} = 0.7$		
The total system impedance as seen by the relay with infeed formulae applied.			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
	$Z_{TR} = (4 + j20) \times 10^{10}\ \Omega$		
Eq. (96)	$Z_{sys} = Z_S \times \left(1 + \frac{Z_L}{Z_{TR}}\right) + \left[Z_L + Z_R \times \left(1 + \frac{Z_L}{Z_{TR}}\right)\right]$		
	$Z_{sys} = 10 + j50\ \Omega$		
The calculated coordinates of the lower loss-of-synchronism circle center.			
Eq. (97)	$Z_{C1} = -\left[Z_S \times \left(1 + \frac{Z_L}{Z_{TR}}\right)\right] - \left[\frac{N^2 \times Z_{sys}}{1 - N^2}\right]$		
	$Z_{C1} = -\left[(2 + j10)\ \Omega \times \left(1 + \frac{(4 + j20)\ \Omega}{(4 + j20) \times 10^{10}\ \Omega}\right)\right] - \left[\frac{0.7^2 \times (10 + j50)\ \Omega}{1 - 0.7^2}\right]$		
	$Z_{C1} = -11.608 - j58.039\ \Omega$		
The calculated radius of the lower loss-of-synchronism circle.			
Eq. (98)	$r_a = \left\lvert \frac{N \times Z_{sys}}{1 - N^2} \right\rvert$		
	$r_a = \left\lvert \frac{0.7 \times (10 + j50)\ \Omega}{1 - 0.7^2} \right\rvert$		
	$r_a = 69.987\ \Omega$		
The calculated coordinates of the upper loss-of-synchronism circle center.			
Given:	$E_S = 1.0$	$E_R = 0.7$	

[17] http://store.gedigitalenergy.com/faq/Documents/Alps/GER-3180.pdf

Table 13: Example Calculation (Voltage Ratios)	
Eq. (99)	$N = \frac{\lvert E_S \rvert}{\lvert E_R \rvert} = \frac{1.0}{0.7} = 1.43$
Eq. (100)	$Z_{C2} = Z_L + \left[Z_R \times \left(1 + \frac{Z_L}{Z_{TR}} \right) \right] + \left[\frac{Z_{sys}}{N^2 - 1} \right]$
	$Z_{C2} = 4 + j20\ \Omega + \left[(4 + j20)\ \Omega \times \left(1 + \frac{(4 + j20)\ \Omega}{(4 + j20) \times 10^{10}\ \Omega} \right) \right] + \left[\frac{(10 + j50)\ \Omega}{1.43^2 - 1} \right]$
	$Z_{C2} = 17.608 + j88.039\ \Omega$
The calculated radius of the upper loss-of-synchronism circle.	
Eq. (101)	$r_b = \left\lvert \frac{N \times Z_{sys}}{N^2 - 1} \right\rvert$
	$r_b = \left\lvert \frac{1.43 \times (10 + j50)\ \Omega}{1.43^2 - 1} \right\rvert$
	$r_b = 69.987\ \Omega$

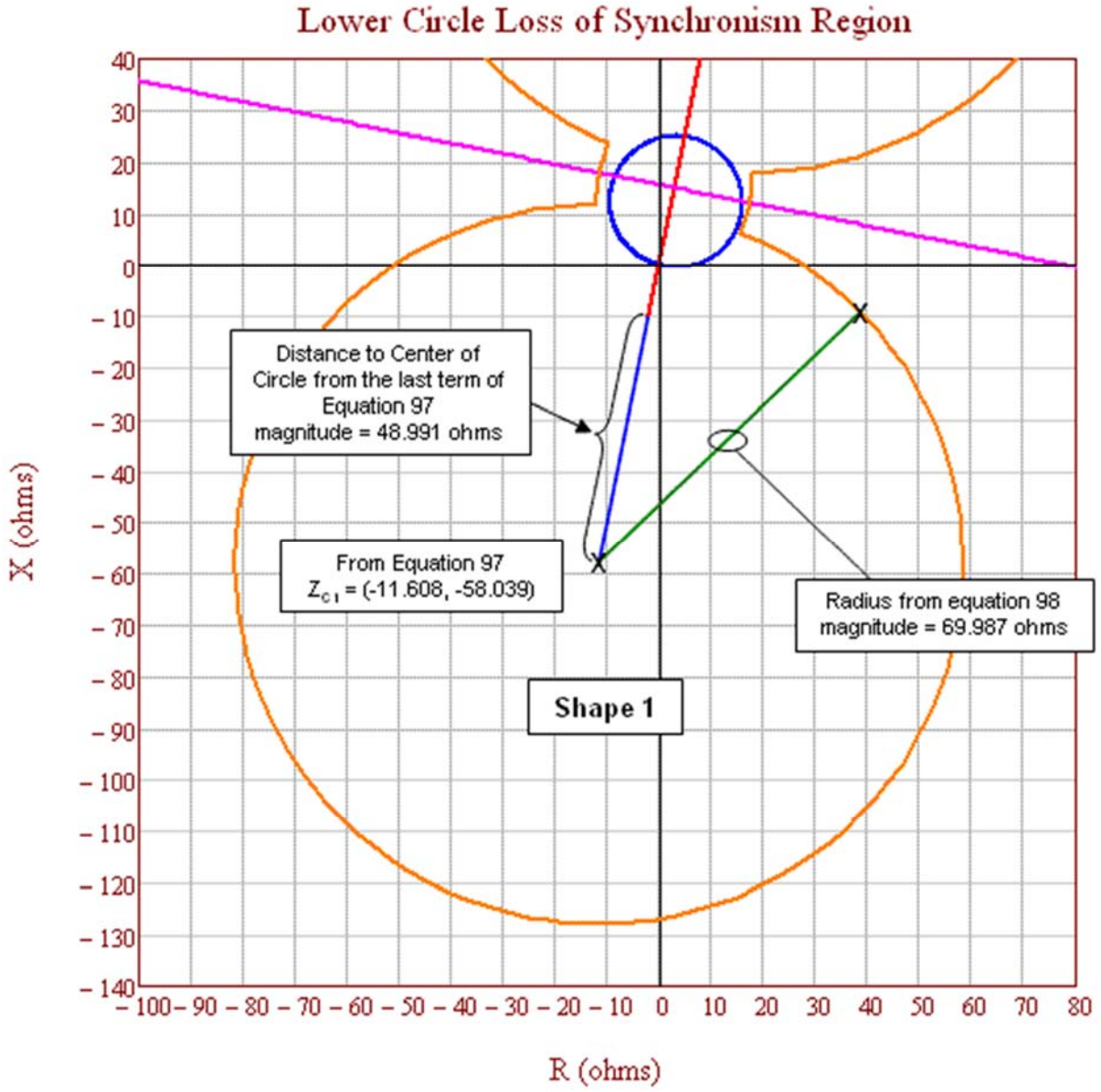

Figure 15a: Lower circle loss-of-synchronism region showing the coordinates of the circle center and the circle radius.

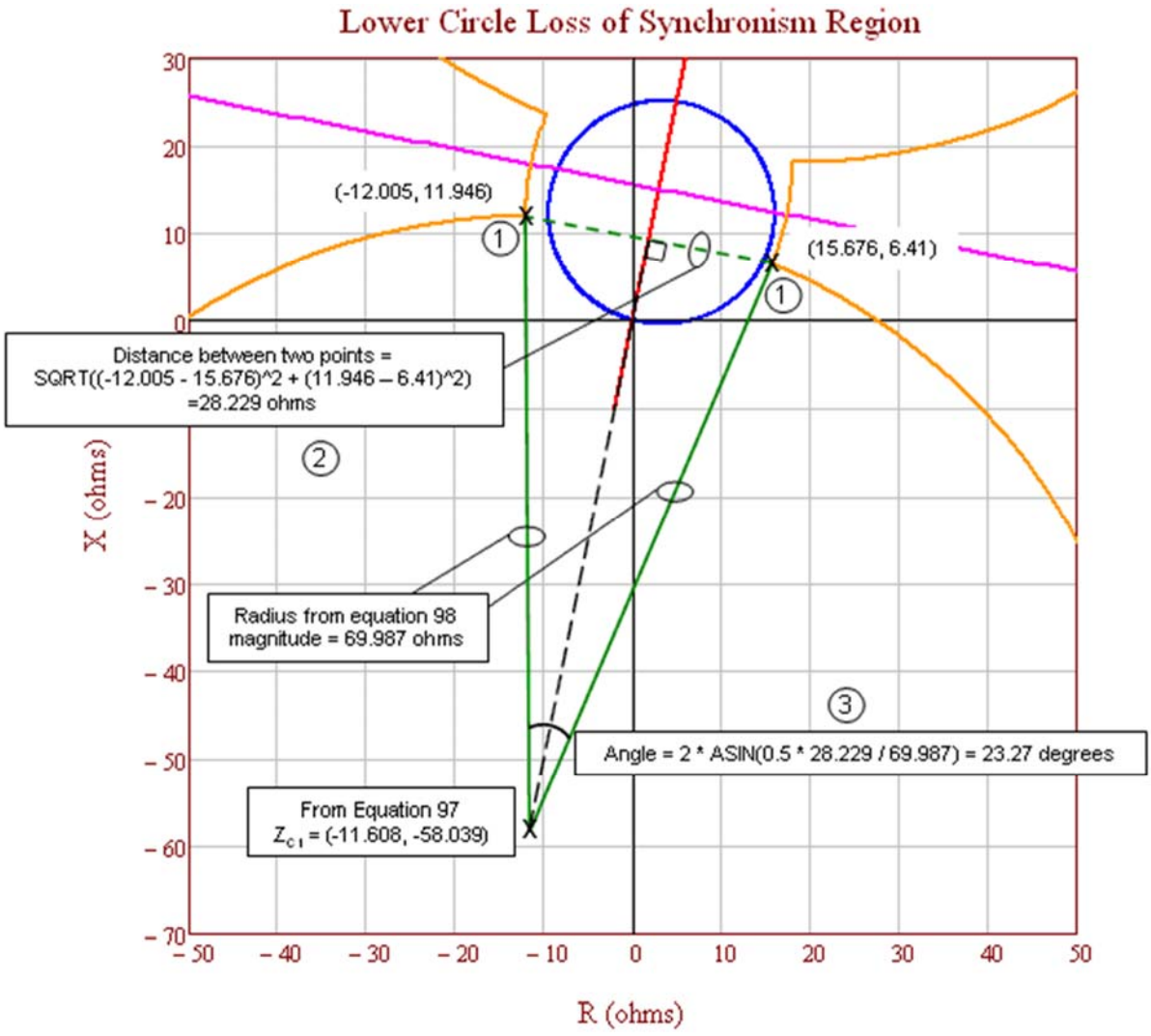

Figure 15b: Lower circle loss-of-synchronism region showing the first three steps to calculate the coordinates of the points on the circle. 1) Identify the lower circle loss-of-synchronism points that intersect the lens shape where the sending-end to receiving-end voltage ratio is 0.7 (see lens shape calculations in Tables 2-7). 2) Calculate the distance between the two lower circle loss-of-synchronism points identified in Step 1. 3) Calculate the angle of arc that connects the two lower circle loss-of-synchronism points identified in Step 1.

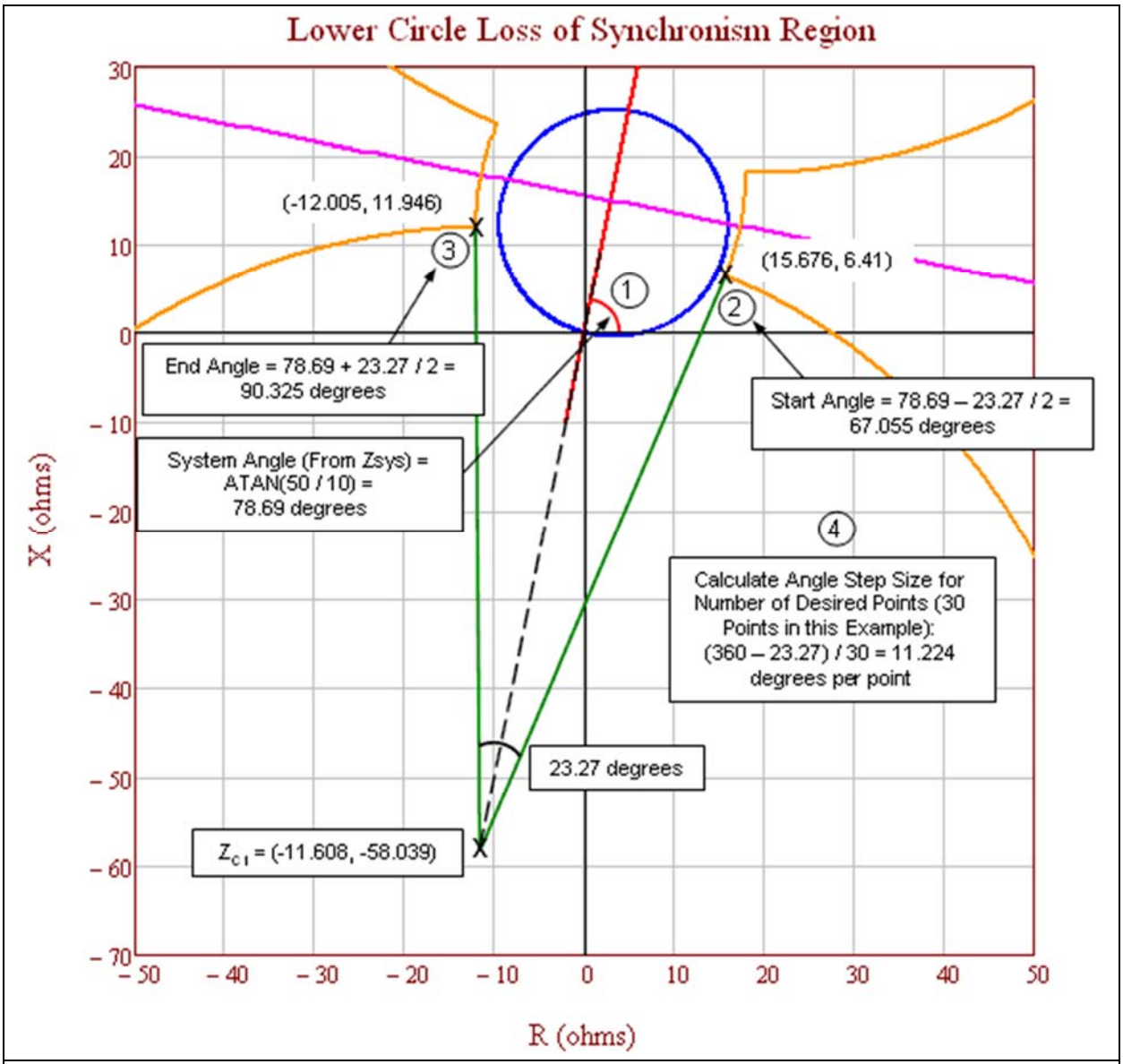

Figure 15c: Lower circle loss-of-synchronism region showing the steps to calculate the start angle, end angle, and the angle step size for the desired number of calculated points. 1) Calculate the system angle. 2) Calculate the start angle. 3) Calculate the end angle. 4) Calculate the angle step size for the desired number of points.

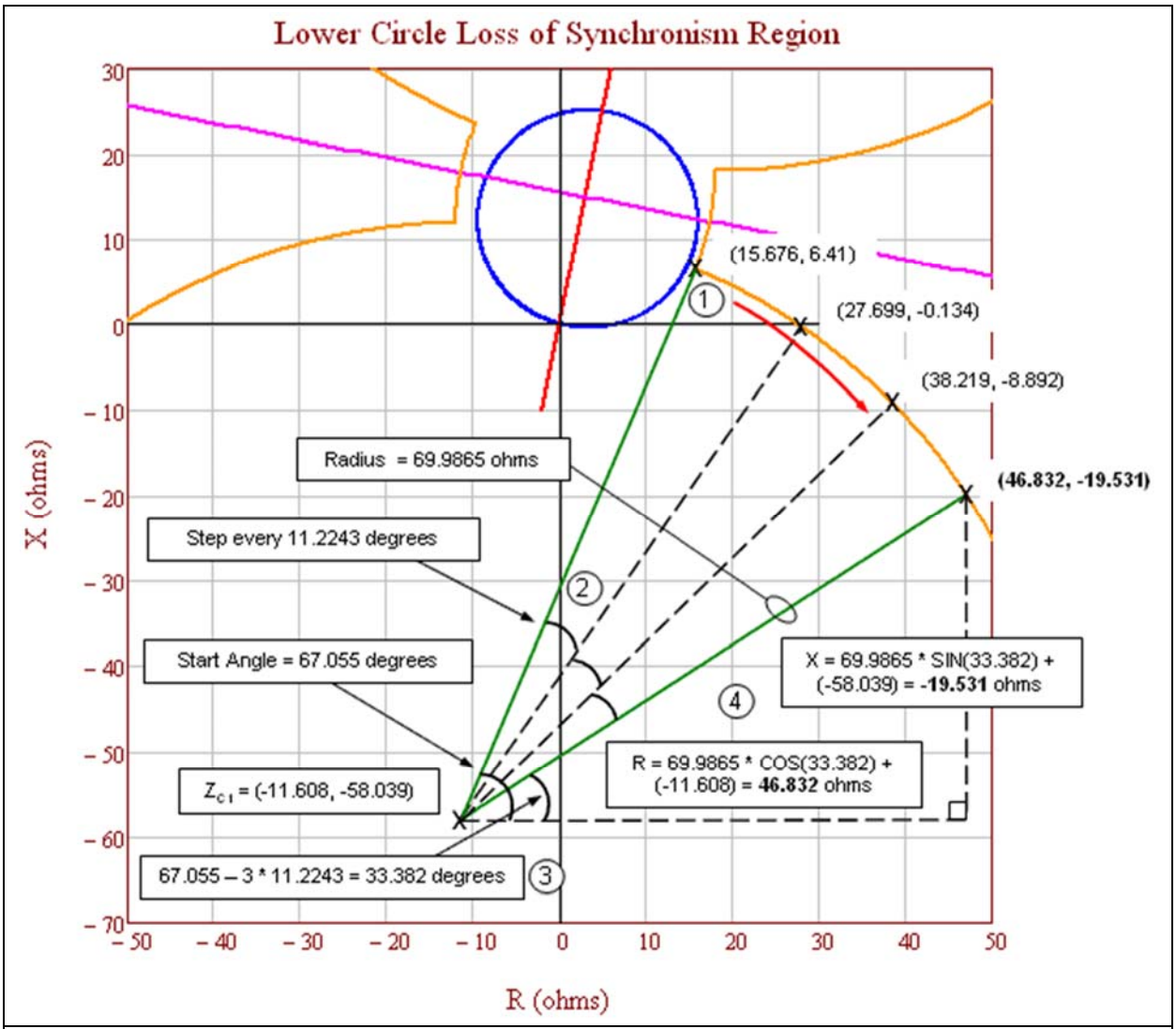

Figure 15d: Lower circle loss-of-synchronism region showing the final steps to calculate the coordinates of the points on the circle. 1) Start at the intersection with the lens shape and proceed in a clockwise direction. 2) Advance the step angle for each point. 3) Calculate the new angle after step advancement. 4) Calculate the R–X coordinates.

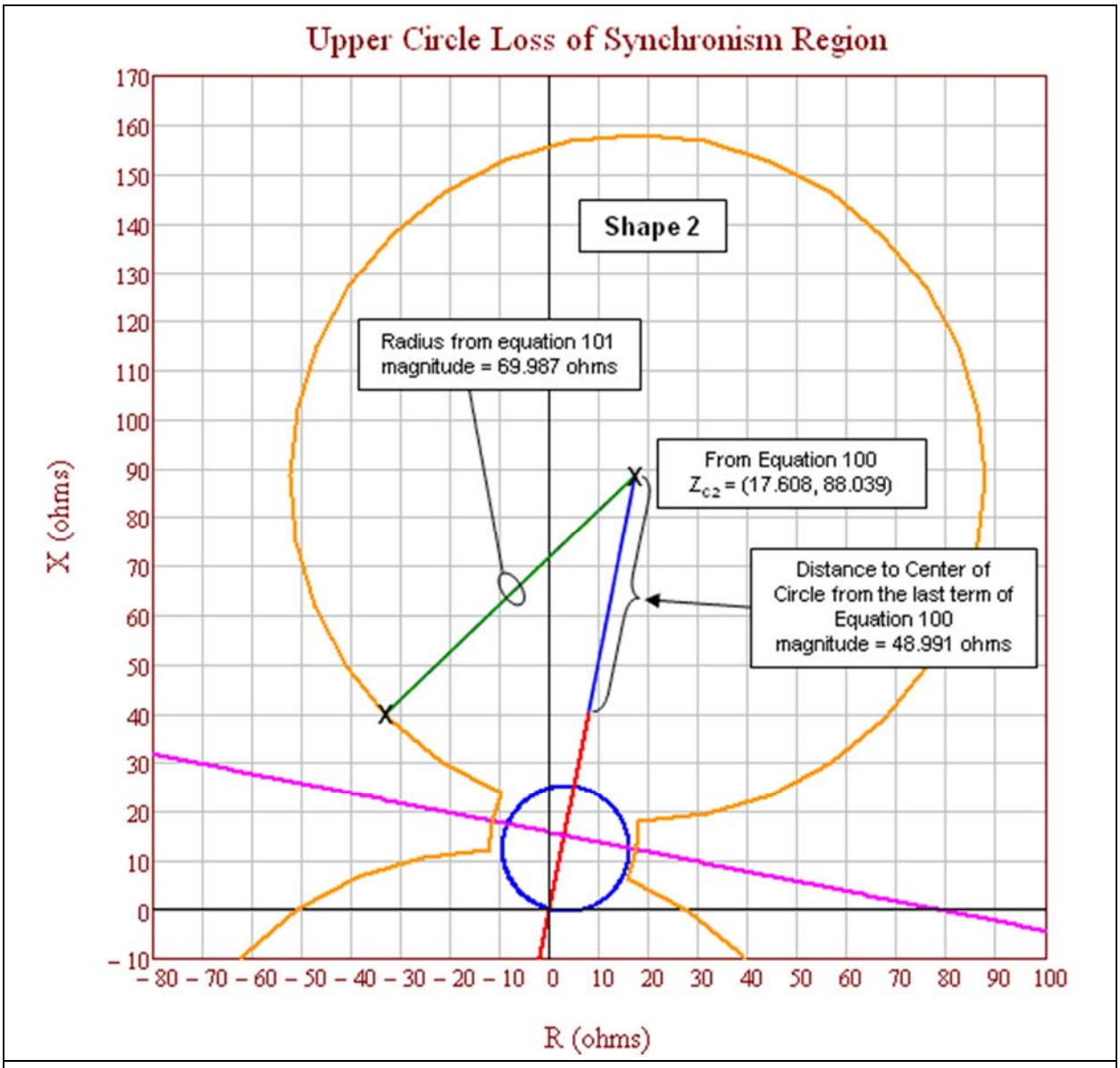

Figure 15e: Upper circle loss-of-synchronism region showing the coordinates of the circle center and the circle radius.

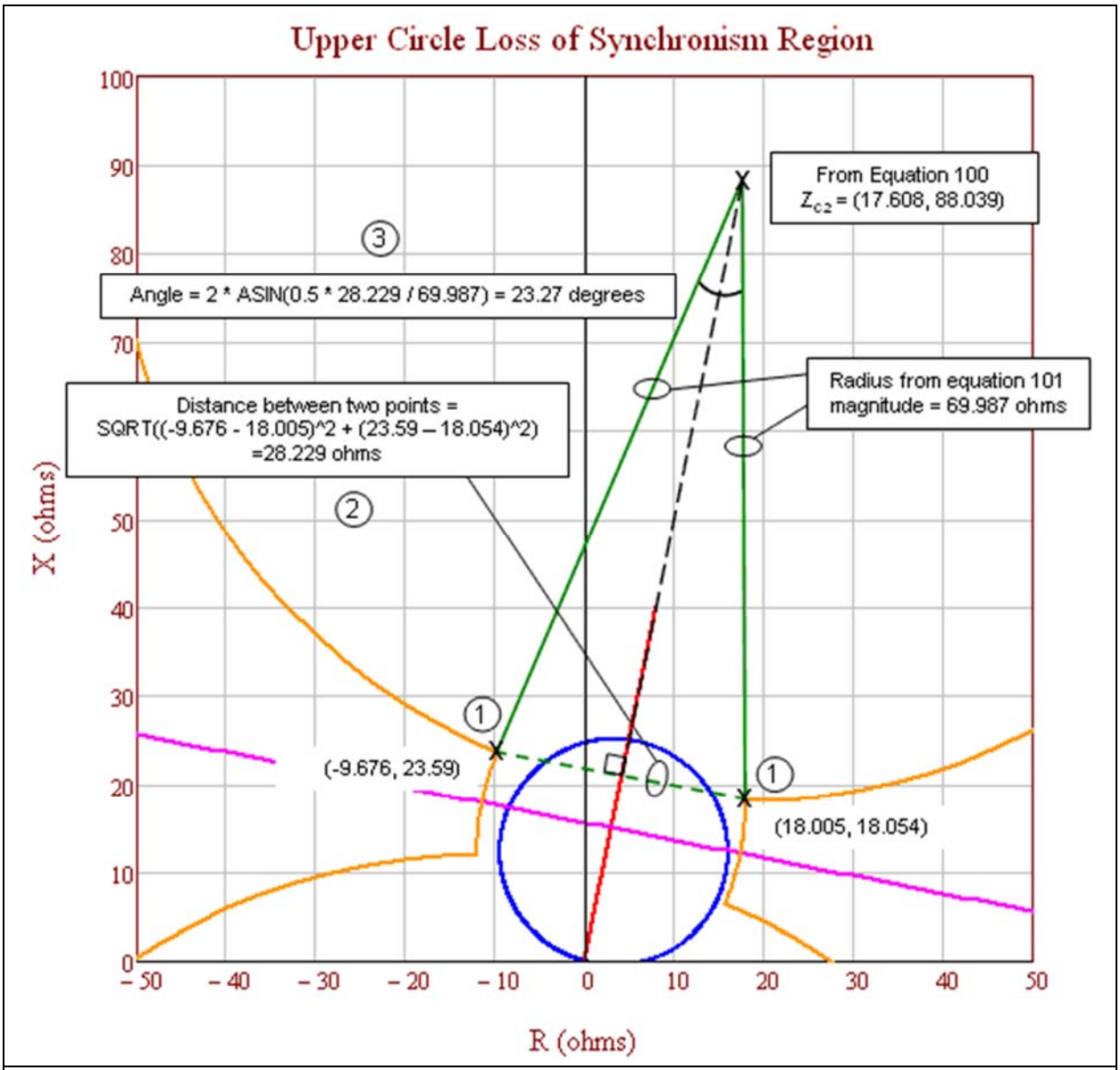

Figure 15f: Upper circle loss-of-synchronism region showing the first three steps to calculate the coordinates of the points on the circle. 1) Identify the upper circle points that intersect the lens shape where the sending-end to receiving-end voltage ratio is 1.43 (see lens shape calculations in Tables 2-7). 2) Calculate the distance between the two upper circle points identified in Step 1. 3) Calculate the angle of arc that connects the two upper circle points identified in Step 1.

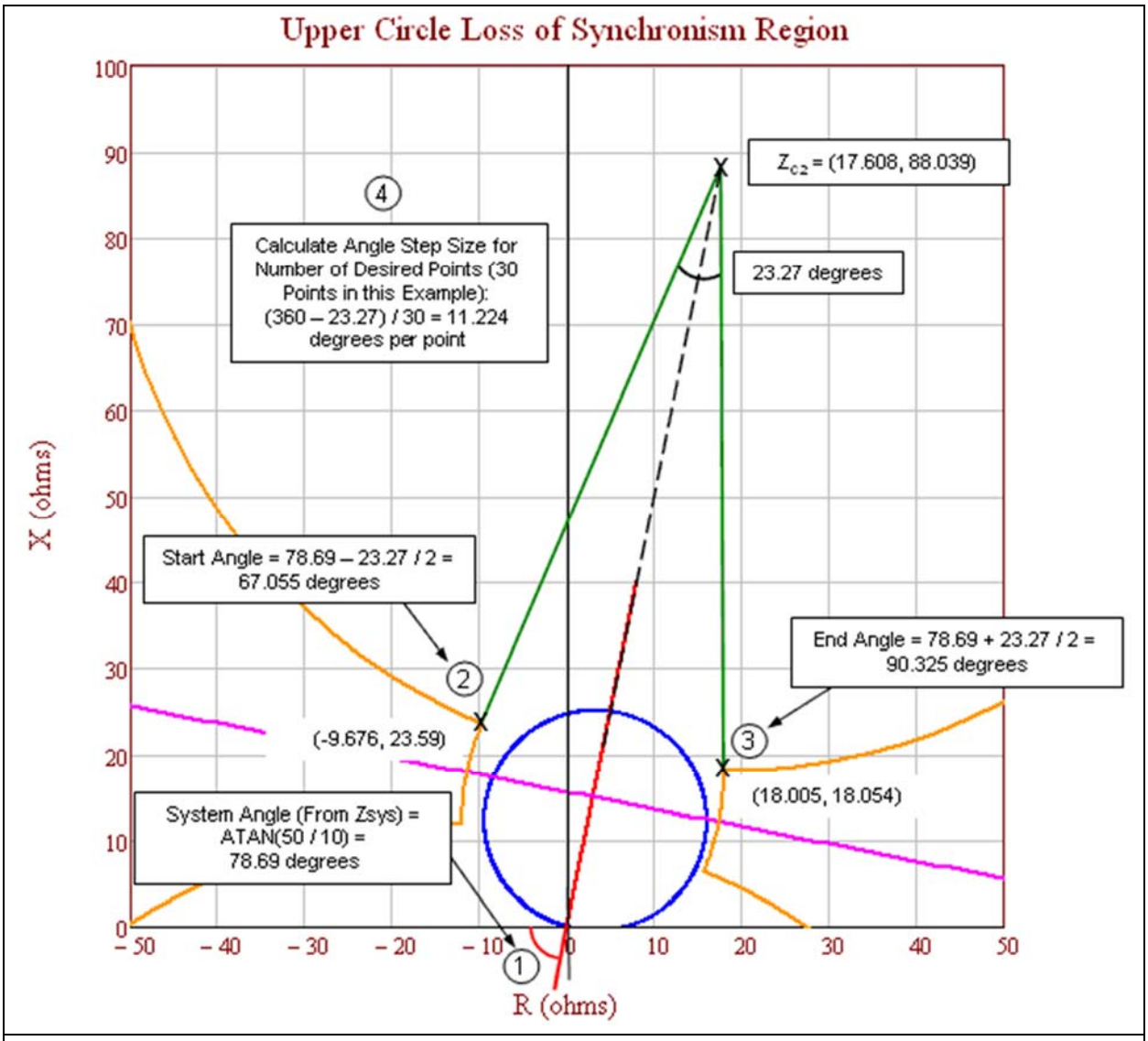

Figure 15g: Upper circle loss-of-synchronism region showing the steps to calculate the start angle, end angle, and the angle step size for the desired number of calculated points. 1) Calculate the system angle. 2) Calculate the start angle. 3) Calculate the end angle. 4) Calculate the angle step size for the desired number of points.

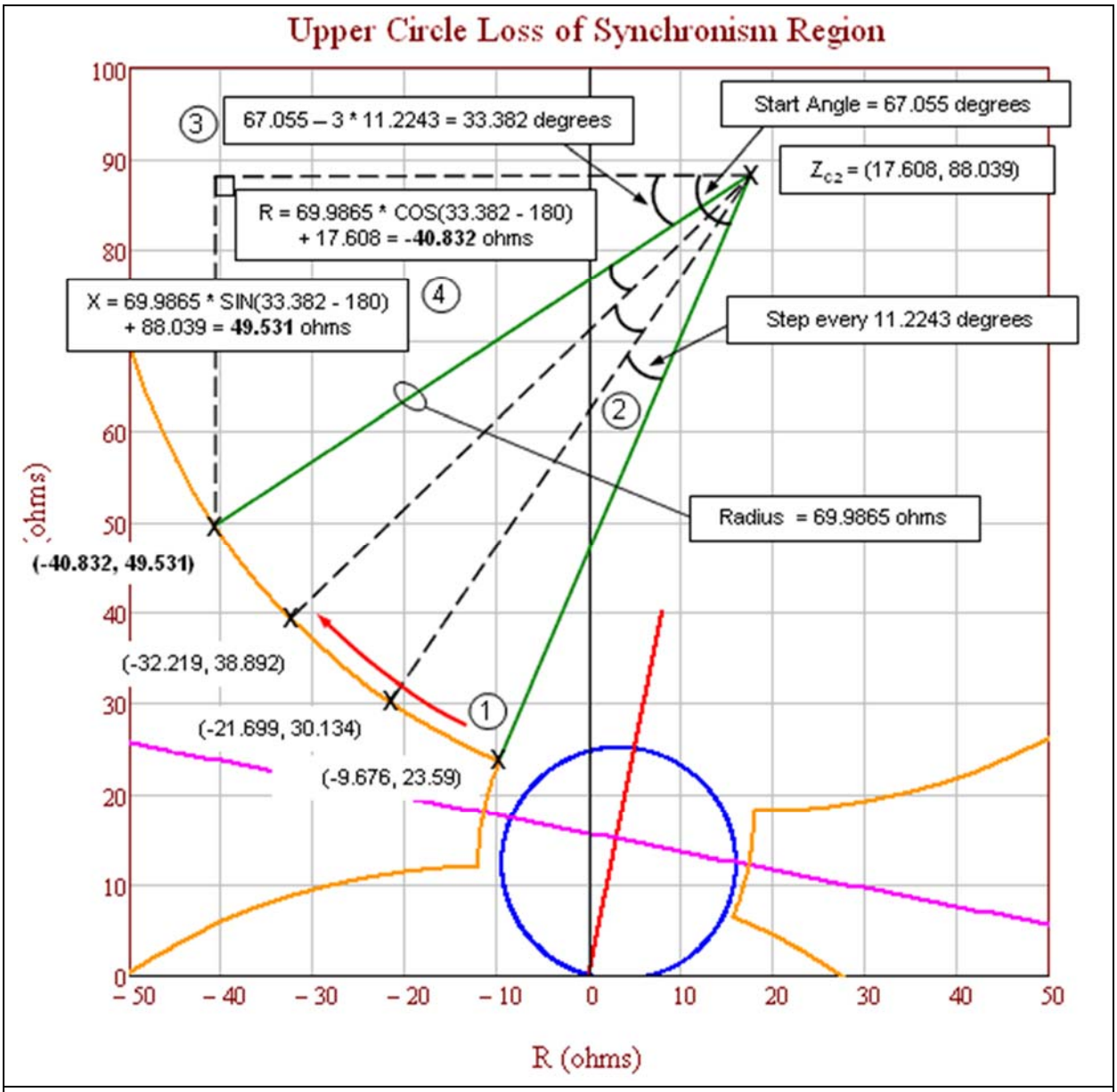

Figure 15h: Upper circle loss-of-synchronism region showing the final steps to calculate the coordinates of the points on the circle. 1) Start at the intersection with the lens shape and proceed in a clockwise direction. 2) Advance the step angle for each point. 3) Calculate the new angle after step advancement. 4) Calculate the R-X coordinates.

Lower Loss of Synchronism Circle Coordinates		
Angle (degrees)	R	+ jX
67.055	15.676	6.41
55.831	27.699	-0.134
44.606	38.219	-8.892
33.382	**46.832**	**-19.531**
22.158	53.21	-31.643
10.933	57.108	-44.765
359.709	58.378	-58.395
348.485	56.97	-72.011
337.26	52.939	-85.092
326.036	46.438	-97.139
314.812	37.717	-107.69
303.587	27.109	-116.341
292.363	15.02	-122.762
281.139	1.913	-126.707
269.914	-11.712	-128.026
258.69	-25.333	-126.667
247.466	-38.429	-122.682
236.241	-50.499	-116.225
225.017	-61.081	-107.542
213.793	-69.771	-96.965
202.568	-76.235	-84.899
191.344	-80.227	-71.806
180.12	-81.594	-58.185
168.895	-80.284	-44.56
157.671	-76.347	-31.45
146.447	-69.933	-19.357
135.222	-61.288	-8.744
123.998	-50.742	-0.016
112.774	-38.699	6.491
101.549	-25.62	10.53
90.325	-12.005	11.946

Upper Loss of Synchronism Circle Coordinates		
Angle (degrees)	R	+ jX
67.055	-9.676	23.59
55.831	-21.699	30.134
44.606	-32.219	38.892
33.382	**-40.832**	**49.531**
22.158	-47.21	61.643
10.933	-51.108	74.765
359.709	-52.378	88.395
348.485	-50.97	102.011
337.26	-46.939	115.092
326.036	-40.438	127.139
314.812	-31.717	137.69
303.587	-21.109	146.341
292.363	-9.02	152.762
281.139	4.087	156.707
269.914	17.712	158.026
258.69	31.333	156.667
247.466	44.429	152.682
236.241	56.499	146.225
225.017	67.081	137.542
213.793	75.771	126.965
202.568	82.235	114.899
191.344	86.227	101.806
180.12	87.594	88.185
168.895	86.284	74.56
157.671	82.347	61.45
146.447	75.933	49.357
135.222	67.288	38.744
123.998	56.742	30.016
112.774	44.699	23.509
101.549	31.62	19.47
90.325	18.005	18.054

Figure 15i: Full tables of calculated lower and upper loss-of-synchronism circle coordinates. The highlighted row is the detailed calculated points in Figures 15d and 15h.

Application Specific to Criterion B

The PRC-026-1 – Attachment B, Criterion B evaluates overcurrent elements used for tripping. The same criteria as PRC-026-1 – Attachment B, Criterion A is used except for an additional criterion (No. 4) that calculates a current magnitude based upon generator internal voltage of 1.05 per unit. A value of 1.05 per unit generator voltage is used to establish a minimum pickup current value for overcurrent relays that have a time delay less than 15 cycles. The sending-end and receiving-end voltages are established at 1.05 per unit at 120 degree system separation angle. The 1.05 per unit is the typical upper end of the operating voltage, which is also consistent with the maximum power

transfer calculation using actual system source impedances in the PRC-023 NERC Reliability Standard. The formulas used to calculate the current are in Table 14 below.

Table 14: Example Calculation (Overcurrent)			
This example is for a 230 kV line terminal with a directional instantaneous phase overcurrent element set to 50 amps secondary times a CT ratio of 160:1 that equals 8,000 amps, primary. The following calculation is where V_S equals the base line-to-ground sending-end generator source voltage times 1.05 at an angle of 120 degrees, V_R equals the base line-to-ground receiving-end generator internal voltage times 1.05 at an angle of 0 degrees, and Z_{sys} equals the sum of the sending-end source, line, and receiving-end source impedances in ohms. Here, the instantaneous phase setting of 8,000 amps is greater than the calculated system current of 5,716 amps; therefore, it meets PRC-026-1 – Attachment B, Criterion B.			
Eq. (102)	$V_S = \frac{V_{LL}\angle 120°}{\sqrt{3}} \times 1.05$		
	$V_S = \frac{230{,}000\angle 120°\ V}{\sqrt{3}} \times 1.05$		
	$V_S = 139{,}430\angle 120°\ V$		
Receiving-end generator terminal voltage.			
Eq. (103)	$V_R = \frac{V_{LL}\angle 0°}{\sqrt{3}} \times 1.05$		
	$V_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}} \times 1.05$		
	$V_R = 139{,}430\angle 0°\ V$		
The total impedance of the system (Z_{sys}) equals the sum of the sending-end source impedance (Z_S), the impedance of the line (Z_L), and receiving-end impedance (Z_R) in ohms.			
Given:	$Z_S = 3 + j26\ \Omega$	$Z_L = 1.3 + j8.7\ \Omega$	$Z_R = 0.3 + j7.3\ \Omega$
Eq. (104)	$Z_{sys} = Z_S + Z_L + Z_R$		
	$Z_{sys} = (3 + j26)\ \Omega + (1.3 + j8.7)\ \Omega + (0.3 + j7.3)\ \Omega$		
	$Z_{sys} = 4.6 + j42\ \Omega$		
Total system current.			
Eq. (105)	$I_{sys} = \frac{(V_S - V_R)}{Z_{sys}}$		
	$I_{sys} = \frac{(139{,}430\angle 120°\ V - 139{,}430\angle 0°\ V)}{(4.6 + j42)\ \Omega}$		
	$I_{sys} = 5{,}715.82\angle 66.25°\ A$		

Application Specific to Three-Terminal Lines

If a three-terminal line is identified as an Element that is susceptible to a power swing based on Requirement R1, the load-responsive protective relays at each end of the three-terminal line must be evaluated.

As shown in Figure 15j, the source impedances at each end of the line can be obtained from the similar short circuit calculation as for the two-terminal line (assuming the parallel transfer impedances are ignored).

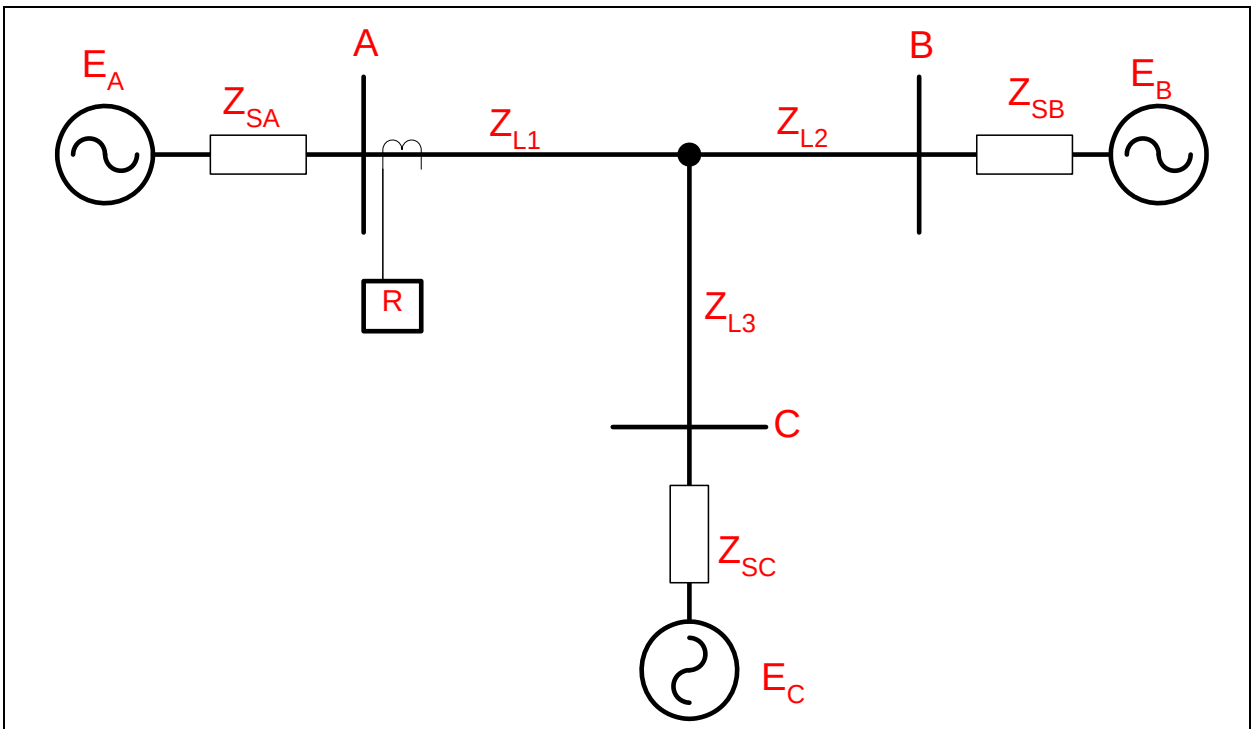

Figure 15j: Three-terminal line. To evaluate the load-responsive protective relays on the three-terminal line at Terminal A, the circuit in Figure 15j is first reduced to the equivalent circuit shown in Figure 15k. The evaluation process for the load-responsive protective relays on the line at Terminal A will now be the same as that of the two-terminal line.

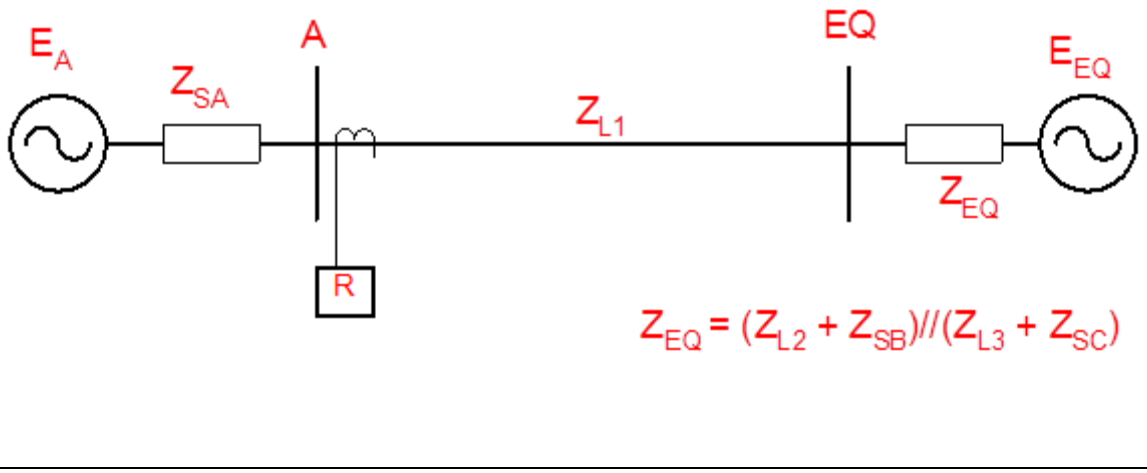

Figure 15k: Three-terminal line reduced to a two-terminal line.

Application to Generation Elements

As with transmission BES Elements, the determination of the apparent impedance seen at an Element located at, or near, a generation Facility is complex for power swings due to various interdependent quantities. These variances in quantities are caused by changes in machine internal voltage, speed governor action, voltage regulator action, the reaction of other local generators, and the reaction of other interconnected transmission BES Elements as the event progresses through the time domain. Though transient stability simulations may be used to determine the apparent impedance for verifying load-responsive relay settings,[18,19] Requirement R2, PRC-026-1 – Attachment B, Criteria A and B provides a simplified method for evaluating the load-responsive protective relay's susceptibility to tripping in response to a stable power swing without requiring stability simulations.

In general, the electrical center will be in the transmission system for cases where the generator is connected through a weak transmission system (high external impedance). In other cases where the generator is connected through a strong transmission system, the electrical center could be inside the unit connected zone.[20] In either case, load-responsive protective relays connected at the generator terminals or at the high-voltage side of the generator step-up (GSU) transformer may be challenged by power swings. Relays that may be challenged by power swings will be determined by the Planning Coordinator in Requirement R1 or by the Generator Owner after becoming aware of a generator, transformer, or transmission line BES Element that tripped[21] in response to a stable or unstable power swing due to the operation of its protective relay(s) in Requirement R2.

[18] Donald Reimert, *Protective Relaying for Power Generation Systems*, Boca Raton, FL, CRC Press, 2006.

[19] Prabha Kundur, *Power System Stability and Control*, EPRI, McGraw Hill, Inc., 1994.

[20] Ibid, Kundur.

[21] See Guidelines and Technical Basis section, "Becoming Aware of an Element That Tripped in Response to a Power Swing,"

Voltage controlled time-overcurrent and voltage-restrained time-overcurrent relays are excluded from this standard. When these relays are set based on equipment permissible overload capability, their operating times are much greater than 15 cycles for the current levels observed during a power swing.

Instantaneous overcurrent, time-overcurrent, and definite-time overcurrent relays with a time delay of less than 15 cycles for the current levels observed during a power swing are applicable and are required to be evaluated for identified Elements.

The generator loss-of-field protective function is provided by impedance relay(s) connected at the generator terminals. The settings are applied to protect the generator from a partial or complete loss of excitation under all generator loading conditions and, at the same time, be immune to tripping on stable power swings. It is more likely that the loss-of-field relay would operate during a power swing when the automatic voltage regulator (AVR) is in manual mode rather than when in automatic mode.[22] Figure 16 illustrates the loss-of-field relay in the R-X plot, which typically includes up to three zones of protection.

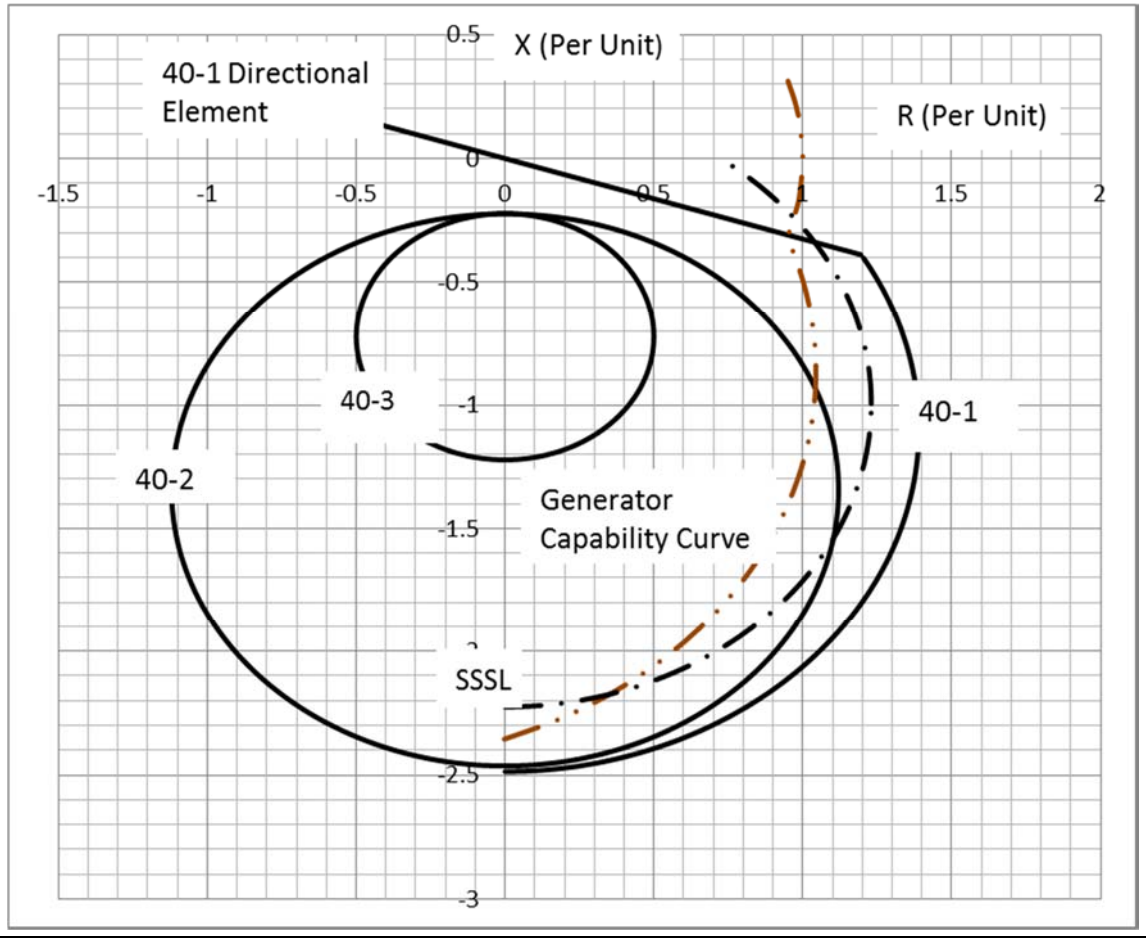

Figure 16: An R-X graph of typical impedance settings for loss-of-field relays.

[22] John Burdy, *Loss-of-excitation Protection for Synchronous Generators GER-3183*, General Electric Company.

Loss-of-field characteristic 40-1 has a wider impedance characteristic (positive offset) than characteristic 40-2 or characteristic 40-3 and provides additional generator protection for a partial loss of field or a loss of field under low load (less than 10% of rated). The tripping logic of this protection scheme is established by a directional contact, a voltage setpoint, and a time delay. The voltage and time delay add security to the relay operation for stable power swings. Characteristic 40-3 is less sensitive to power swings than characteristic 40-2 and is set outside the generator capability curve in the leading direction. Regardless of the relay impedance setting, PRC-019[23] requires that the "in-service limiters operate before Protection Systems to avoid unnecessary trip" and "in-service Protection System devices are set to isolate or de-energize equipment in order to limit the extent of damage when operating conditions exceed equipment capabilities or stability limits." Time delays for tripping associated with loss-of-field relays[24,25] have a range from 15 cycles for characteristic 40-2 to 60 cycles for characteristic 40-1 to minimize tripping during stable power swings. In PRC-026-1, 15 cycles establishes a threshold for applicability; however, it is the responsibility of the Generator Owner to establish settings that provide security against stable power swings and, at the same time, dependable protection for the generator.

The simple two-machine system circuit (method also used in the Application to Transmission Elements section) is used to analyze the effect of a power swing at a generator facility for load-responsive relays. In this section, the calculation method is used for calculating the impedance seen by the relay connected at a point in the circuit.[26] The electrical quantities used to determine the apparent impedance plot using this method are generator saturated transient reactance (X'_d), GSU transformer impedance (X_{GSU}), transmission line impedance (Z_L), and the system equivalent (Z_e) at the point of interconnection. All impedance values are known to the Generator Owner except for the system equivalent. The system equivalent is obtainable from the Transmission Owner. The sending-end and receiving-end source voltages are varied from 0.0 to 1.0 per unit to form the lens shape portion of the unstable power swing region. The voltage range of 0.7 to 1.0 results in a ratio range from 0.7 to 1.43. This ratio range is used to form the lower and upper loss-of-synchronism circle shapes of the unstable power swing region. A system separation angle of 120 degrees is used in accordance with PRC-026-1 – Attachment B criteria for each load-responsive protective relay evaluation.

Table 15 below is an example calculation of the apparent impedance locus method based on Figures 17 and 18.[27] In this example, the generator is connected to the 345 kV transmission system through the GSU transformer and has the listed ratings. Note that the load-responsive protective relays in this example may have ownership with the Generator Owner or the Transmission Owner.

[23] Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

[24] Ibid, Burdy.

[25] *Applied Protective Relaying*, Westinghouse Electric Corporation, 1979.

[26] Edward Wilson Kimbark, *Power System Stability, Volume II: Power Circuit Breakers and Protective Relays*, Published by John Wiley and Sons, 1950.

[27] Ibid, Kimbark.

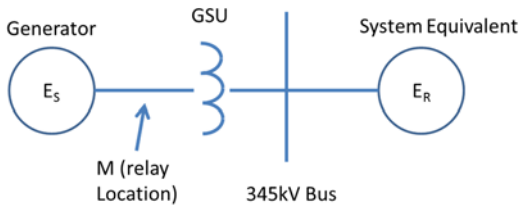

Figure 17: Simple one-line diagram of the system to be evaluated.

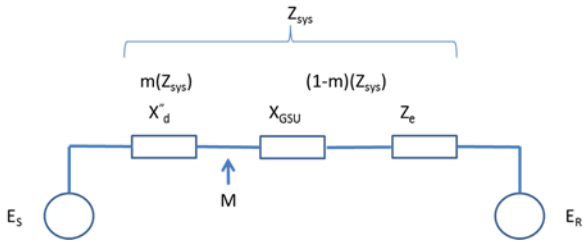

Figure 18: Simple system equivalent impedance diagram to be evaluated.[28]

Table15: Example Data (Generator)	
Input Descriptions	**Input Values**
Synchronous Generator nameplate (MVA)	940 MVA
Saturated transient reactance (940 MVA base)	$X'_d = 0.3845$ per unit
Generator rated voltage (Line-to-Line)	20 kV
Generator step-up (GSU) transformer rating	880 MVA
GSU transformer reactance (880 MVA base)	$X_{GSU} = 16.05\%$
System Equivalent (100 MVA base)	$Z_e = 0.00723\angle 90°$ per unit
Generator Owner Load-Responsive Protective Relays	
40-1	Positive Offset Impedance
	Offset = 0.294 per unit
	Diameter = 0.294 per unit
40-2	Negative Offset Impedance
	Offset = 0.22 per unit
	Diameter = 2.24 per unit
40-3	Negative Offset Impedance
	Offset = 0.22 per unit
	Diameter = 1.00 per unit
21-1	Diameter = 0.643 per unit
	MTA = 85°

[28] Ibid, Kimbark.

Table15: Example Data (Generator)	
50	I (pickup) = 5.0 per unit
Transmission Owned Load-Responsive Protective Relays	
21-2	Diameter = 0.55 per unit
	MTA = 85°

Calculations shown for a 120 degree angle and $E_S/E_R = 1$. The equation for calculating Z_R is:[29]

Eq. (106) $$Z_R = \left(\frac{(1-m)(E_S\angle\delta) + (m)(E_R)}{E_S\angle\delta - E_R}\right) \times Z_{sys}$$

Where m is the relay location as a function of the total impedance (real number less than 1)

E_S and E_R is the sending-end and receiving-end voltages

Z_{sys} is the total system impedance

Z_R is the complex impedance at the relay location and plotted on an R-X diagram

All of the above are constants (940 MVA base) while the angle δ is varied. Table 16 below contains calculations for a generator using the data listed in Table 15.

Table16: Example Calculations (Generator)			
The following calculations are on a 940 MVA base.			
Given:	$X'_d = j0.3845\ pu$	$X_{GSU} = j0.17144\ pu$	$Z_e = j0.06796\ pu$
Eq. (107)	$Z_{sys} = X'_d + X_{GSU} + Z_e$		
	$Z_{sys} = j0.3845\ pu + j0.17144\ pu + j0.06796\ pu$		
	$Z_{sys} = 0.6239\ \angle 90°\ pu$		
Eq. (108)	$m = \frac{X'_d}{Z_{sys}} = \frac{0.3845}{0.6239} = 0.6163$		
Eq. (109)	$Z_R = \left(\frac{(1-m)(E_S\angle\delta) + (m)(E_R)}{E_S\angle\delta - E_R}\right) \times Z_{sys}$		
	$Z_R = \left(\frac{(1-0.6163) \times (1\angle 120°) + (0.6163)(1\angle 0°)}{1\angle 120° - 1\angle 0°}\right) \times (0.6239\angle 90°)\ pu$		

[29] Ibid, Kimbark.

Table16: Example Calculations (Generator)	
	$Z_R = \left(\frac{0.4244 + j0.3323}{-1.5 + j\ 0.866}\right) \times (0.6239\angle 90°)\ pu$
	$Z_R = (0.3116 \angle -111.95°) \times (0.6239\angle 90°)\ pu$
	$Z_R = 0.194 \angle -21.95°\ pu$
	$Z_R = -0.18 - j0.073\ pu$

Table 17 lists the swing impedance values at other angles and at E_S/E_R = 1, 1.43, and 0.7. The impedance values are plotted on an R-X graph with the center being at the generator terminals for use in evaluating impedance relay settings.

Table 17: Sample Calculations for a Swing Impedance Chart for Varying Voltages at the Sending-End and Receiving-End.

	E_S/E_R=1		E_S/E_R=1.43		E_S/E_R=0.7	
	Z_R		Z_R		Z_R	
Angle (δ) (Degrees)	Magnitude (pu)	Angle (Degrees)	Magnitude (pu)	Angle (Degrees)	Magnitude (pu)	Angle (Degrees)
90	0.320	-13.1	0.296	6.3	0.344	-31.5
120	0.194	-21.9	0.173	-0.4	0.227	-40.1
150	0.111	-41.0	0.082	-10.3	0.154	-58.4
210	0.111	-25.9	0.082	190.3	0.154	238.4
240	0.194	201.9	0.173	180.4	0.225	220.1
270	0.320	193.1	0.296	173.7	0.344	211.5

Requirement R2 Generator Examples

Distance Relay Application

Based on PRC-026-1 – Attachment B, Criterion A, the distance relay (21-1) (i.e., owned by the Generation Owner) characteristic is in the region where a stable power swing would not occur as shown in Figure 19. There is no further obligation to the owner in this standard for this load-responsive protective relay.

The distance relay (21-2) (i.e., owned by the Transmission Owner) is connected at the high-voltage side of the GSU transformer and its impedance characteristic is in the region where a stable power swing could occur causing the relay to operate. In this example, if the intentional time delay of this relay is less than 15 cycles, the PRC-026 – Attachment B, Criterion A cannot be met, thus the Transmission Owner is required to create a CAP (Requirement R3). Some of the options include,

but are not limited to, changing the relay setting (i.e., impedance reach, angle, time delay), modify the scheme (i.e., add PSB), or replace the Protection System. Note that the relay may be excluded from this standard if it has an intentional time delay equal to or greater than 15 cycles.

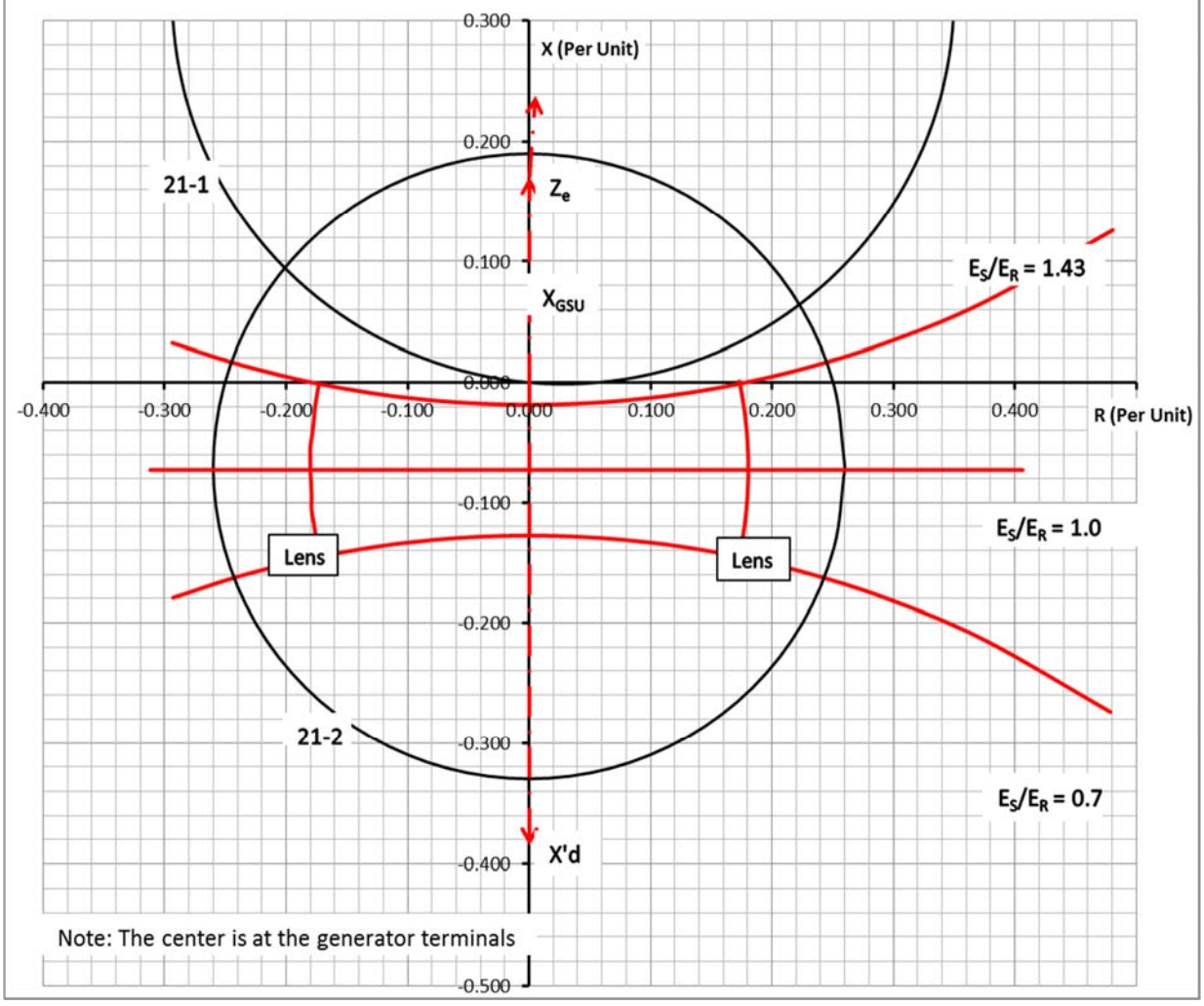

Figure 19: Swing impedance graph for impedance relays at a generating facility.

Loss-of-Field Relay Application

In Figure 20, the R-X diagram shows the loss-of-field relay (40-1 and 40-2) characteristics are in the region where a stable power swing can cause a relay operation. Protective relay 40-1 would be excluded if it has an intentional time delay equal to or greater than 15 cycles. Similarly, 40-2 would be excluded if its intentional time delay is equal to or greater than 15 cycles. For example, if 40-1 has a time delay of 1 second and 40-2 has a time delay of 0.25 seconds, they are excluded and there is no further obligation on the Generator Owner in this standard for these relays. The

loss-of-field relay characteristic 40-3 is entirely inside the unstable power swing region. In this case, the owner may select high speed tripping on operation of the 40-3 impedance element.

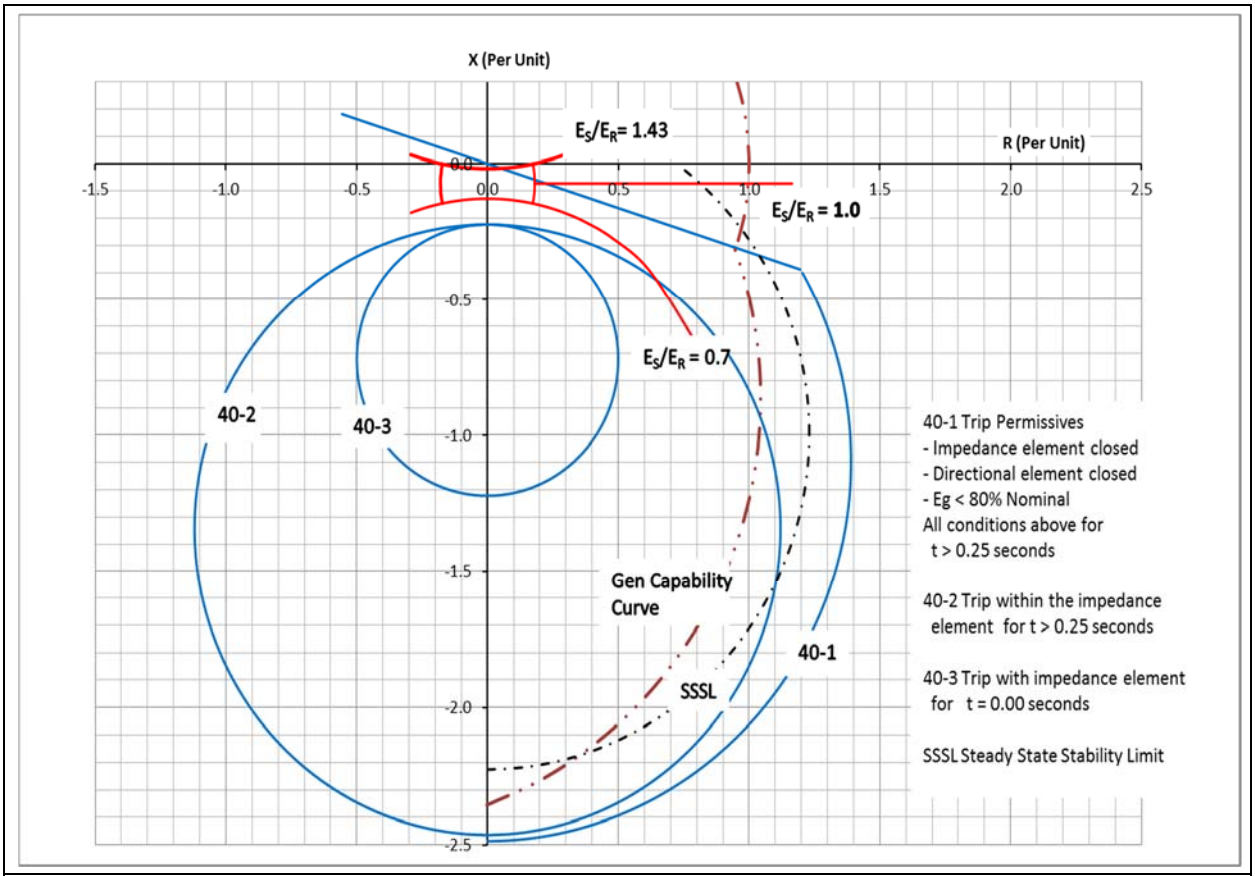

Figure 20: Typical R-X graph for loss-of-field relays with a portion of the unstable power swing region defined by PRC-026-1 – Attachment B, Criterion A.

Instantaneous Overcurrent Relay

In similar fashion to the transmission line overcurrent example calculation in Table 14, the instantaneous overcurrent relay minimum setting is established by PRC-026-1 – Attachment B, Criterion B. The solution is found by:

Eq. (110) $$I_{sys} = \frac{E_S - E_R}{Z_{\text{sys}}}$$

As stated in the relay settings in Table 15, the relay is installed on the high-voltage side of the GSU transformer with a pickup of 5.0 per unit. The maximum allowable current is calculated below.

$$I_{sys} = \frac{(1.05\angle 120° - 1.05\angle 0°)}{0.6239\angle 90°}\ pu$$

$$I_{sys} = \frac{1.819\angle 150°}{0.6239\angle 90°} pu$$

$$I_{sys} = 2.91\ \angle 60°\ pu$$

The instantaneous phase setting of 5.0 per unit is greater than the calculated system current of 2.91 per unit; therefore, it meets the PRC-026-1 – Attachment B, Criterion B.

Out-of-Step Tripping for Generation Facilities

Out-of-step protection for the generator generally falls into three different schemes. The first scheme is a distance relay connected at the high-voltage side of the GSU transformer with the directional element looking toward the generator. Because this relay setting may be the same setting used for generator backup protection (see Requirement R2 Generator Examples, Distance Relay Application), it is susceptible to tripping in response to stable power swings and would require modification. Because this scheme is susceptible to tripping in response to stable power swings and any modification to the mho circle will jeopardize the overall protection of the out-of-step protection of the generator, available technical literature does not recommend using this scheme specifically for generator out-of-step protection. The second and third out-of-step Protection System schemes are commonly referred to as single and double blinder schemes. These schemes are installed or enabled for out-of-step protection using a combination of blinders, a mho element, and timers. The combination of these protective relay functions provides out-of-step protection and discrimination logic for stable and unstable power swings. Single blinder schemes use logic that discriminate between stable and unstable power swings by issuing a trip command after the first slip cycle. Double blinder schemes are more complex than the single blinder scheme and, depending on the settings of the inner blinder, a trip for a stable power swing may occur. While the logic discriminates between stable and unstable power swings in either scheme, it is important that the trip initiating blinders be set at an angle greater than the stability limit of 120 degrees to remove the possibility of a trip for a stable power swing. Below is a discussion of the double blinder scheme.

Double Blinder Scheme

The double blinder scheme is a method for measuring the rate of change of positive sequence impedance for out-of-step swing detection. The scheme compares a timer setting to the actual elapsed time required by the impedance locus to pass between two impedance characteristics. In this case, the two impedance characteristics are simple blinders, each set to a specific resistive reach on the R-X plane. Typically, the two blinders on the left half plane are the mirror images of those on the right half plane. The scheme typically includes a mho characteristic which acts as a starting element, but is not a tripping element.

The scheme detects the blinder crossings and time delays as represented on the R-X plane as shown in Figure 21. The system impedance is composed of the generator transient (X_d'), GSU transformer (X_T), and transmission system (X_{system}), impedances.

The scheme logic is initiated when the swing locus crosses the outer Blinder R1 (Figure 21), on the right at separation angle α. The scheme only commits to take action when a swing crosses the

inner blinder. At this point the scheme logic seals in the out-of-step trip logic at separation angle β. Tripping actually asserts as the impedance locus leaves the scheme characteristic at separation angle δ.

The power swing may leave both inner and outer blinders in either direction, and tripping will assert. Therefore, the inner blinder must be set such that the separation angle β is large enough that the system cannot recover. This angle should be set at 120 degrees or more. Setting the angle greater than 120 degrees satisfies the PRC-026-1 – Attachment B, Criterion A (No. 1, 1st bullet) since the tripping function is asserted by the blinder element. Transient stability studies may indicate that a smaller stability limit angle is acceptable under PRC-026-1 – Attachment B, Criterion A (No. 1, 2nd bullet). In this respect, the double blinder scheme is similar to the double lens and triple lens schemes and many transmission application out-of-step schemes.

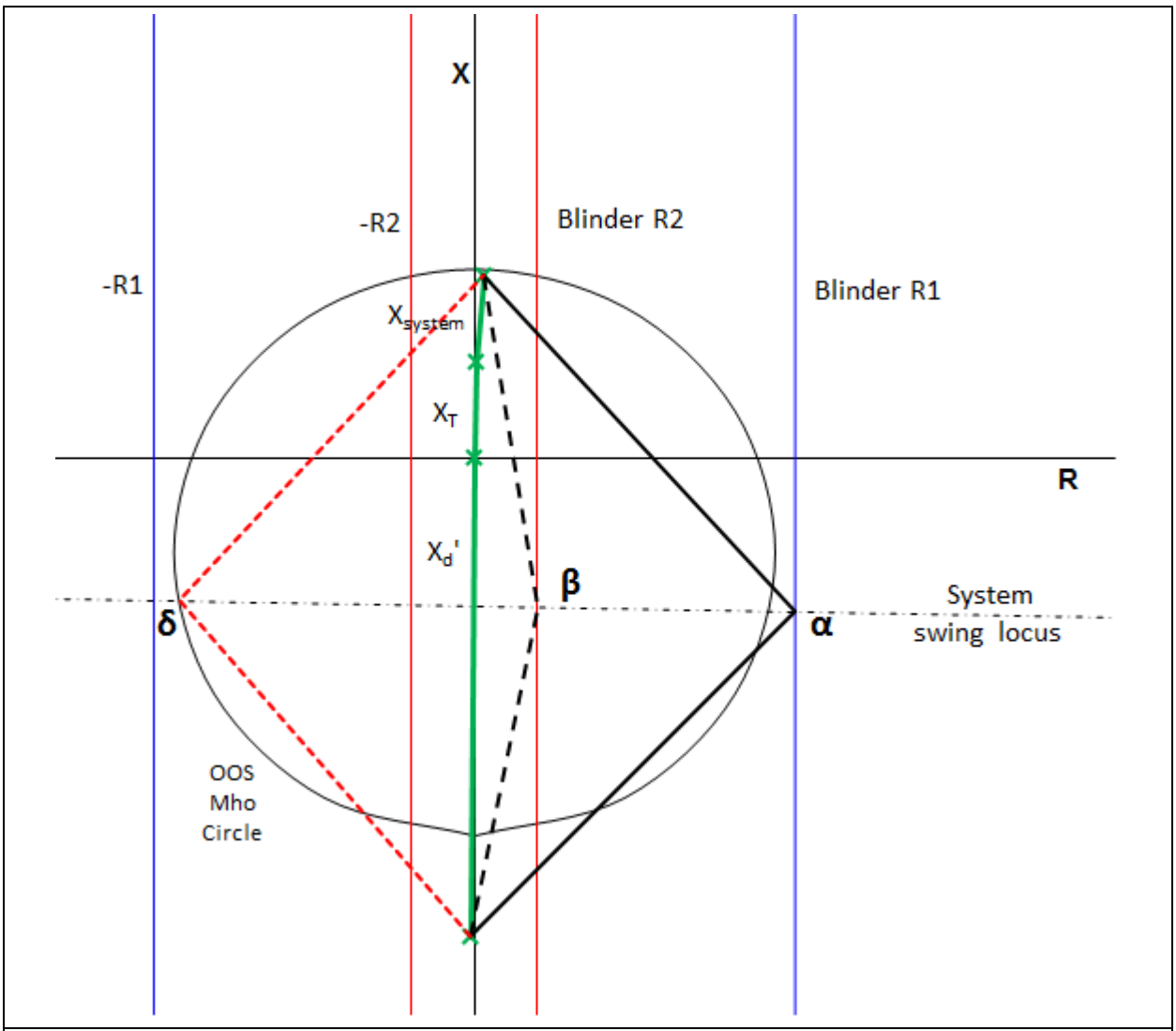

Figure 21: Double Blinder Scheme generic out of step characteristics.

Figure 22 illustrates a sample setting of the double blinder scheme for the example 940 MVA generator. The only setting requirement for this relay scheme is the right inner blinder, which must be set greater than the separation angle of 120 degrees (or a lesser angle based on a transient stability study) to ensure that the out-of-step protective function is expected to not trip in response to a stable power swing during non-Fault conditions. Other settings such as the mho characteristic, outer blinders, and timers are set according to transient stability studies and are not a part of this standard.

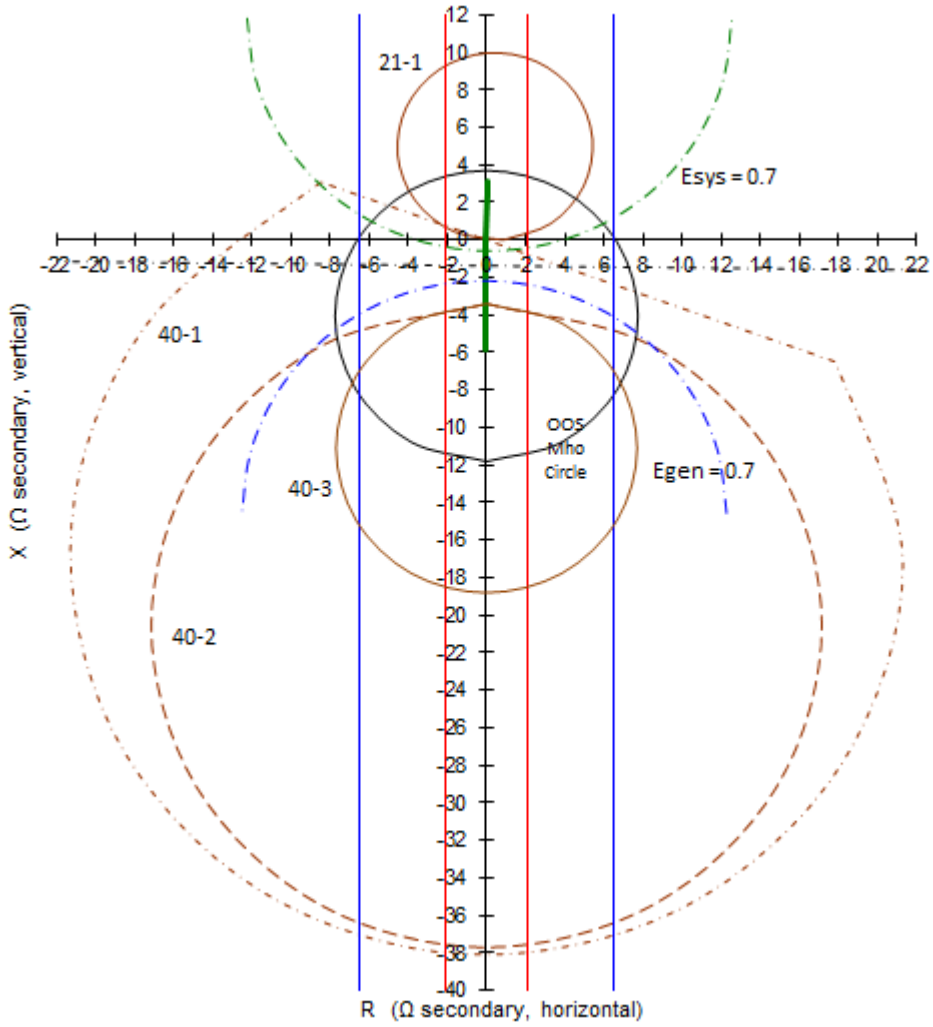

Figure 22: Double Blinder Out-of-Step Scheme with unit impedance data and load-responsive protective relay impedance characteristics for the example 940 MVA generator, scaled in relay secondary ohms.

Requirement R3

To achieve the stated purpose of this standard, which is to ensure that relays are expected to not trip in response to stable power swings during non-Fault conditions, this Requirement ensures that the applicable entity develops a Corrective Action Plan (CAP) that reduces the risk of relays tripping in response to a stable power swing during non-Fault conditions that may occur on any applicable BES Element.

Requirement R4

To achieve the stated purpose of this standard, which is to ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions, the applicable entity is required to implement any CAP developed pursuant to Requirement R3 such that the Protection System will meet PRC-026-1 – Attachment B criteria or can be excluded under the PRC-026-1 – Attachment A criteria (e.g., modifying the Protection System so that relay functions are supervised by power swing blocking or using relay systems that are immune to power swings), while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the BES Element). Protection System owners are required in the implementation of a CAP to update it when actions or timetable change, until all actions are complete. Accomplishing this objective is intended to reduce the occurrence of Protection System tripping during a stable power swing, thereby improving reliability and minimizing risk to the BES.

The following are examples of actions taken to complete CAPs for a relay that did not meet PRC-026-1 – Attachment B and could be at-risk of tripping in response to a stable power swing during non-Fault conditions. A Protection System change was determined to be acceptable (without diminishing the ability of the relay to protect for faults within its zone of protection).

> **Example R4a:** Actions: Settings were issued on 6/02/2015 to reduce the Zone 2 reach of the impedance relay used in the directional comparison unblocking (DCUB) scheme from 30 ohms to 25 ohms so that the relay characteristic is completely contained within the lens characteristic identified by the criterion. The settings were applied to the relay on 6/25/2015. CAP was completed on 06/25/2015.
>
> **Example R4b:** Actions: Settings were issued on 6/02/2015 to enable out-of-step blocking on the existing microprocessor-based relay to prevent tripping in response to stable power swings. The setting changes were applied to the relay on 6/25/2015. CAP was completed on 06/25/2015.

The following is an example of actions taken to complete a CAP for a relay responding to a stable power swing that required the addition of an electromechanical power swing blocking relay.

> **Example R4c:** Actions: A project for the addition of an electromechanical power swing blocking relay to supervise the Zone 2 impedance relay was initiated on 6/5/2015 to prevent tripping in response to stable power swings. The relay installation was completed on 9/25/2015. CAP was completed on 9/25/2015.

The following is an example of actions taken to complete a CAP with a timetable that required updating for the replacement of the relay.

> **Example R4d:** Actions: A project for the replacement of the impedance relays at both terminals of line X with line current differential relays was initiated on 6/5/2015 to prevent tripping in response to stable power swings. The completion of the project was postponed due to line outage rescheduling from 11/15/2015 to 3/15/2016. Following the timetable change, the impedance relay replacement was completed on 3/18/2016. CAP was completed on 3/18/2016.

The CAP is complete when all the documented actions to remedy the specific problem (i.e., unnecessary tripping during stable power swings) are completed.

Justification for Including Unstable Power Swings in the Requirements

Protection Systems that are applicable to the Standard and must be secure for a stable power swing condition (i.e., meets PRC-026-1 – Attachment B criteria) are identified based on Elements that are susceptible to both stable and unstable power swings. This section provides an example of why Elements that trip in response to unstable power swings (in addition to stable power swings) are identified and that their load-responsive protective relays need to be evaluated under PRC-026-1 – Attachment B criteria.

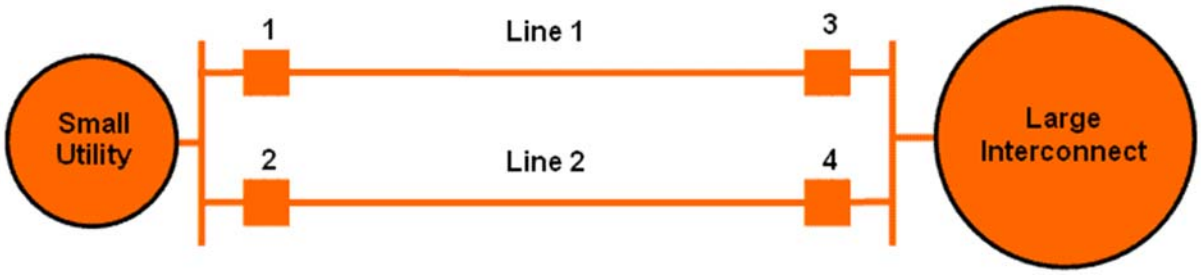

Figure 23: A simple electrical system where two lines tie a small utility to a much larger interconnection.

In Figure 23 the relays at circuit breakers 1, 2, 3, and 4 are equipped with a typical overreaching Zone 2 pilot system, using a Directional Comparison Blocking (DCB) scheme. Internal faults (or power swings) will result in instantaneous tripping of the Zone 2 relays if the measured fault or power swing impedance falls within the zone 2 operating characteristic. These lines will trip on

pilot Zone 2 for out-of-step conditions if the power swing impedance characteristic enters into Zone 2. All breakers are rated for out-of-phase switching.

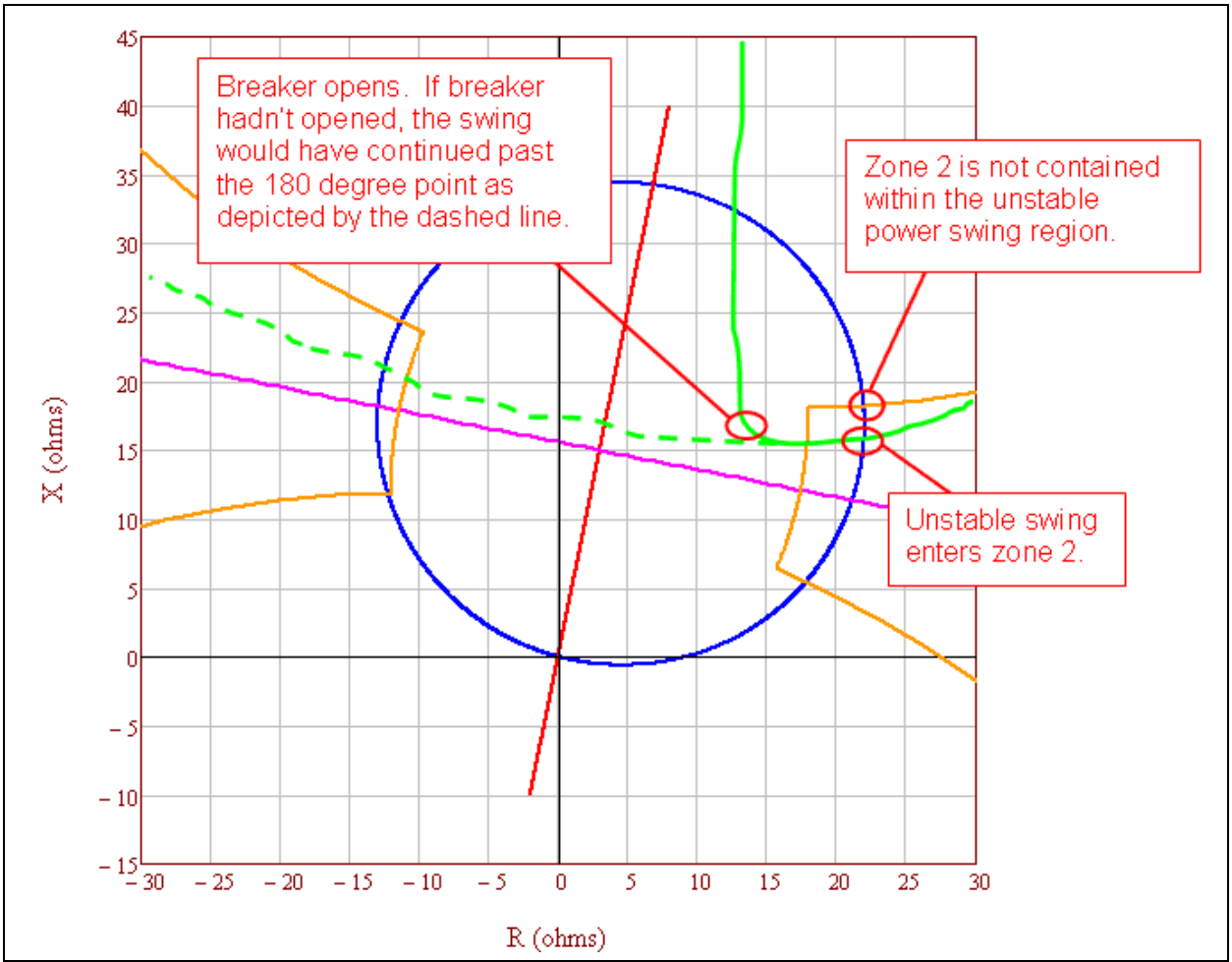

Figure 24: In this case, the Zone 2 element on circuit breakers 1, 2, 3, and 4 did not meet the PRC-026-1 – Attachment B criteria (this figure depicts the power swing as seen by relays on breakers 3 and 4).

In Figure 24, a large disturbance occurs within the small utility and its system goes out-of-step with the large interconnect. The small utility is importing power at the time of the disturbance. The actual power swing, as shown by the solid green line, enters the Zone 2 relay characteristic on the terminals of Lines 1, 2, 3, and 4 causing both lines to trip as shown in Figure 25.

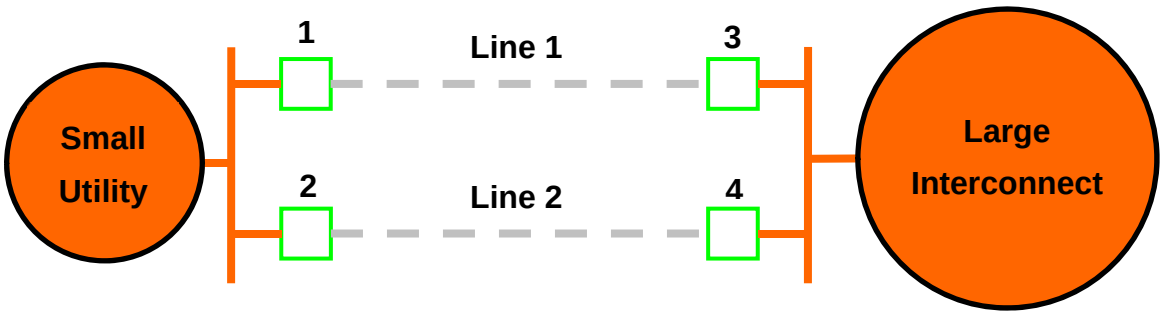

Figure 25: Islanding of the small utility due to Lines 1 and 2 tripping in response to an unstable power swing.

In Figure 25, the relays at circuit breakers 1, 2, 3, and 4 have correctly tripped due to the unstable power swing (shown by the dashed green line in Figure 24), de-energizing Lines 1 and 2, and creating an island between the small utility and the big interconnect. The small utility shed 500 MW of load on underfrequency and maintained a load to generation balance.

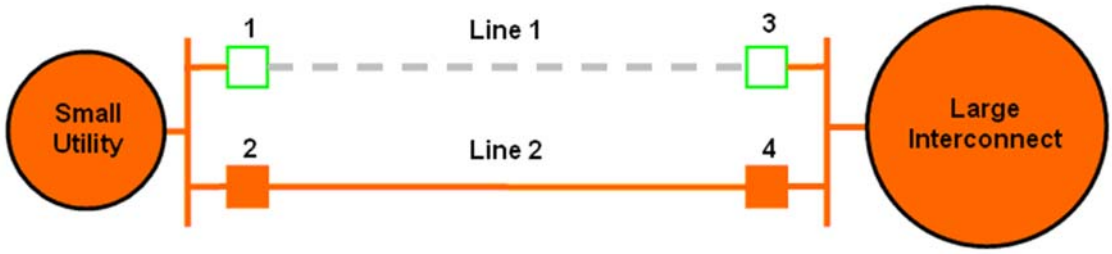

Figure 26: Line 1 is out-of-service for maintenance, Line 2 is loaded beyond its normal rating (but within its emergency rating).

Subsequent to the correct tripping of Lines 1 and 2 for the unstable power swing in Figure 25, another system disturbance occurs while the system is operating with Line 1 out-of-service for maintenance. The disturbance causes a stable power swing on Line 2, which challenges the relays at circuit breakers 2 and 4 as shown in Figure 27.

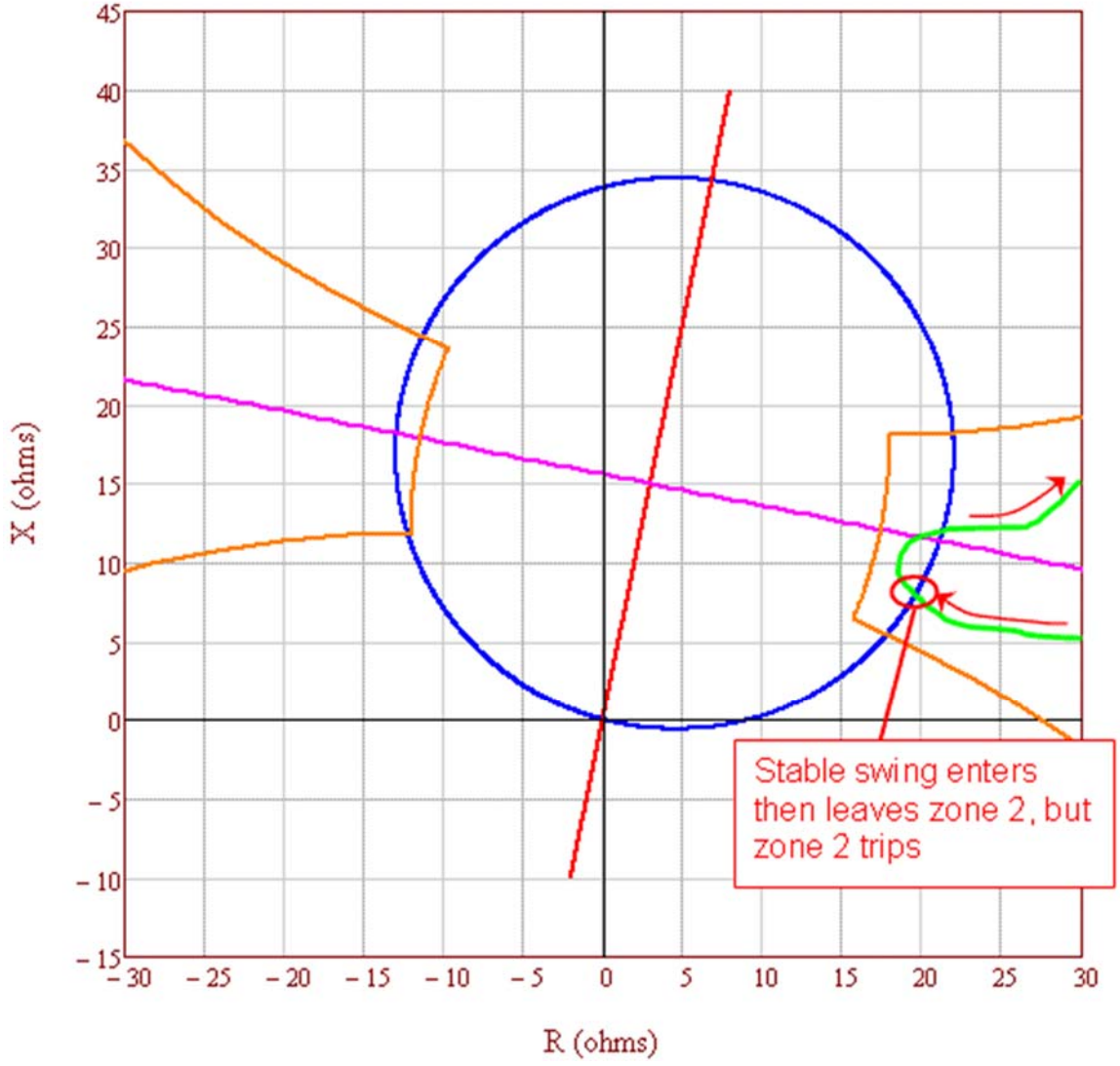

Figure 27: Relays on circuit breakers 2 and 4 were not addressed to meet the PRC-026-1 – Attachment B criteria following the previous unstable power swing event.

If the relays on circuit breakers 2 and 4 were not addressed under the Requirements for the previous unstable power swing condition, the relays would trip in response to the stable power swing, which would result in unnecessary system separation, load shedding, and possibly cascading or blackout.

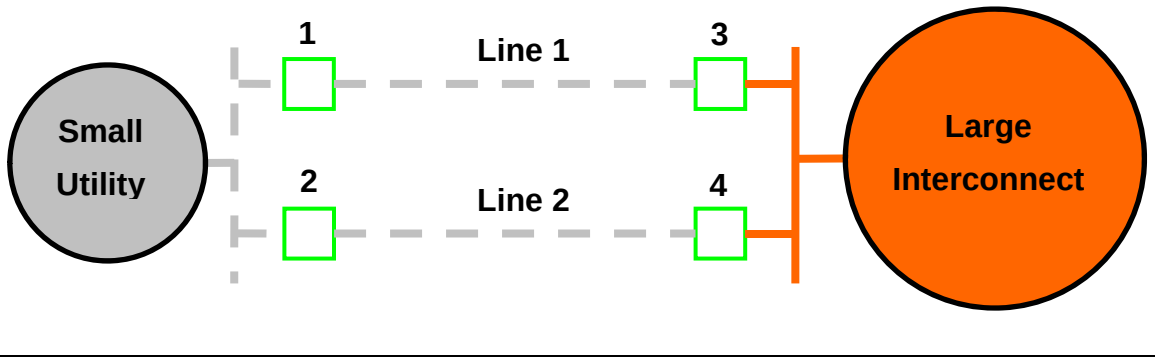

Figure 28: Possible blackout of the small utility.

If the relays that tripped in response to the previous unstable power swing condition in Figure 24 were addressed under the Requirements to meet PRC-026-1 - Attachment B criteria, the unnecessary tripping of the relays for the stable power swing shown in Figure 28 would have been averted, and the possible blackout of the small utility would have been avoided.

Rationale

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

Rationale for R1

The Planning Coordinator has a wide-area view and is in the position to identify generator, transformer, and transmission line BES Elements which meet the criteria, if any. The criteria-based approach is consistent with the NERC System Protection and Control Subcommittee (SPCS) technical document *Protection System Response to Power Swings*, August 2013 ("PSRPS Report"),[30] which recommends a focused approach to determine an at-risk BES Element. See the Guidelines and Technical Basis for a detailed discussion of the criteria.

Rationale for R2

The Generator Owner and Transmission Owner are in a position to determine whether their load-responsive protective relays meet the PRC-026-1 – Attachment B criteria. Generator, transformer, and transmission line BES Elements are identified by the Planning Coordinator in Requirement R1 and by the Generator Owner and Transmission Owner following an actual event where the Generator Owner and Transmission Owner became aware (i.e., through an event analysis or

[30] NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

Protection System review) tripping was due to a stable or unstable power swing. A period of 12 calendar months allows sufficient time for the entity to conduct the evaluation.

Rationale for R3

To meet the reliability purpose of the standard, a CAP is necessary to ensure the entity's Protection System meets the PRC-026-1 – Attachment B criteria (1st bullet) so that protective relays are expected to not trip in response to stable power swings. A CAP may also be developed to modify the Protection System for exclusion under PRC-026-1 – Attachment A (2nd bullet). Such an exclusion will allow the Protection System to be exempt from the Requirement for future events. The phrase, "…while maintaining dependable fault detection and dependable out-of-step tripping…" in Requirement R3 describes that the entity is to comply with this standard, while achieving their desired protection goals. Refer to the Guidelines and Technical Basis, Introduction, for more information.

Rationale for R4

Implementation of the CAP must accomplish all identified actions to be complete to achieve the desired reliability goal. During the course of implementing a CAP, updates may be necessary for a variety of reasons such as new information, scheduling conflicts, or resource issues. Documenting CAP changes and completion of activities provides measurable progress and confirmation of completion.

Rationale for Attachment B (Criterion A)

The PRC-026-1 – Attachment B, Criterion A provides a basis for determining if the relays are expected to not trip for a stable power swing having a system separation angle of up to 120 degrees with the sending-end and receiving-end voltages varying from 0.7 to 1.0 per unit (See Guidelines and Technical Basis).

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

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
45-day formal comment period with ballot	09/29/17 – 11/14/17

Anticipated Actions	Date
~~45-day formal comment period with ballot~~	~~September 2017 – November 2017~~
45-day formal comment period with additional ballot	~~January~~August 2018 – ~~February~~October 2018
10-day final ballot	~~February~~October 2018
NERC Board adoption	~~May~~November 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 and each of its Transmission Planners, 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~~the owner-provided Facility Ratings used in ~~accordance with its~~ operations per the Reliability Coordinator's SOL Methodology. ~~If~~ The process may allow the ~~Planning Coordinator uses~~use of 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.~~if: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- The Facility has higher Facility Ratings as a result of a planned upgrade, addition, or Corrective Action Plan;
- Facility Rating differences are due to variations in ambient temperature assumptions;
- The Planning Coordinator provided a technical rationale for using a less limiting Facility Rating to each affected Transmission Planner and Reliability Coordinator; or
- The Transmission Planner provided a technical rationale for using a less limiting Facility Rating to each affected Planning Coordinator and Reliability Coordinator.

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 and each of its Transmission Planners 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~~used in ~~accordance with its~~ operations per the 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]*

- The Planning Coordinator may use less limiting System Voltage Limits if it provides a technical rationale for using a less limiting System Voltage Limits to each affected Transmission Planner and Reliability Coordinator.
- The Transmission Planner may use less limiting System Voltage Limits if it provides a technical rationale for using a less limiting System Voltage Limits to each affected Planning Coordinator and Reliability Coordinator.

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 and each of its Transmission Planners 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~~used in ~~its~~ operations per the 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]*

- The Planning Coordinator may use less limiting stability performance criteria if it provides a technical rationale for using less limiting stability performance criteria to each affected Transmission Planner and Reliability Coordinator.
- The Transmission Planner may use less limiting stability performance criteria if it provides a technical rationale for using less limiting stability performance criteria to each affected Planning Coordinator and Reliability Coordinator.

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.**~~R4. ~~Each Planning Coordinator~~and each Transmission Planner 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 (Planning Coordinator only) to each impacted Reliability Coordinator ~~and~~, Transmission Operator, Transmission Owner, and Generation Owner. This communication shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- ~~6~~4.1 The type of instability identified (e.g., voltage collapse, angular instability, transient voltage dip criteria violation);
- ~~6~~4.2 The associated stability criteria used as part of determining the instability;
- ~~6~~4.3 The associated Contingency(ies) ~~which result(s) in~~and any Facilities critical to the instability, Cascading or uncontrolled separation;
- ~~6.4~~4.4 A description of the studied System conditions when the instability, Cascading or uncontrolled separation was identified;
- 4.5 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
- 4.6~~.5~~ Any Corrective Action Plan associated with the instability, Cascading or uncontrolled separation.

~~**M6.**~~M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator and Transmission Planner communicated the information in accordance with Requirement ~~R6~~R4.

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~~R4 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.~~N/A	The Planning Coordinator or a Transmission Planner 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.~~failed to identify the exclusion criteria allowing the use of less limiting Facility Ratings.	The Planning Coordinator or a Transmission Planner 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.~~N/A	The Planning Coordinator or a Transmission Planner 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~~provide its	The Planning Coordinator or a Transmission Planner 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

			technical ~~justification~~rationale.	Reliability Coordinator's SOL Methodology.
R3.	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.~~N/A	The Planning Coordinator or a Transmission Planner used less limiting stability performance criteria than the stability performance criteria established in its Reliability Coordinator's SOL Methodology, but did not ~~document the~~provide its technical ~~justification~~rationale.	The Planning Coordinator or a Transmission Planner failed to implement a process to ensure that stability performance criteria used in ~~planning assessments~~Planning Assessments are equally limiting or more limiting than ~~those used in operations~~the stability performance criteria 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~~R4.	The Planning Coordinator or Transmission Planner communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator ~~and~~, Transmission Operator, Transmission Owner and Generator Owner, but the communication did not contain one of the elements listed in Requirement ~~R6~~R4, Parts ~~6~~4.1 – 4.6.~~5.~~	The Planning Coordinator or Transmission Planner communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator ~~and~~, Transmission Operator, Transmission Owner and Generator Owner, but the communication did not contain two of the elements listed in Requirement ~~R6~~R4, Parts ~~6~~4.1 – 4.6.~~5.~~	The Planning Coordinator or Transmission Planner communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator ~~and~~, Transmission Operator, Transmission Owner and Generator Owner, but the communication did not contain three elements listed in Requirement ~~R6~~R4, Parts ~~6~~4.1 – 4.6.~~5.~~	The Planning Coordinator or Transmission Planner communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator ~~and~~, Transmission Operator, Transmission Owner and Generator Owner, but the communication did not contain four or more of the elements listed in Requirement ~~R6~~R4, Parts ~~6~~4.1 – 4.6.~~5~~. OR The Planning Coordinator failed to communicate any identified instability, Cascading, or uncontrolled separation to each impacted

				Reliability Coordinator ~~and~~, Transmission Operator, Transmission Owner and Generator Owner.

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

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

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
45-day formal comment period with ballot	09/29/17 – 11/14/17

Anticipated Actions	Date
45-day formal comment period with additional ballot	August 2018 – October 2018
10-day final ballot	October 2018
NERC Board adoption	November 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 and each of its Transmission Planners, 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 the owner-provided Facility Ratings used in operations per the Reliability Coordinator's SOL Methodology. The process may allow the use of less limiting Facility Ratings if: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- The Facility has higher Facility Ratings as a result of a planned upgrade, addition, or Corrective Action Plan;
- Facility Rating differences are due to variations in ambient temperature assumptions;
- The Planning Coordinator provided a technical rationale for using a less limiting Facility Rating to each affected Transmission Planner and Reliability Coordinator; or
- The Transmission Planner provided a technical rationale for using a less limiting Facility Rating to each affected Planning Coordinator and Reliability Coordinator.

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 and each of its Transmission Planners 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 used in operations per the Reliability Coordinator's SOL Methodology. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- The Planning Coordinator may use less limiting System Voltage Limits if it provides a technical rationale for using less limiting System Voltage Limits to each affected Transmission Planner and Reliability Coordinator.
- The Transmission Planner may use less limiting System Voltage Limits if it provides a technical rationale for using less limiting System Voltage Limits to each affected Planning Coordinator and Reliability Coordinator.

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 and each of its Transmission Planners 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 used in operations per the Reliability Coordinator's SOL Methodology. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- The Planning Coordinator may use less limiting stability performance criteria if it provides a technical rationale for using less limiting stability performance criteria to each affected Transmission Planner and Reliability Coordinator.
- The Transmission Planner may use less limiting stability performance criteria if it provides a technical rationale for using less limiting stability performance criteria to each affected Planning Coordinator and Reliability Coordinator.

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 and each Transmission Planner 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 (Planning Coordinator only) to each impacted Reliability Coordinator, Transmission Operator, Transmission Owner, and Generation Owner. This communication shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1 The type of instability identified (e.g., voltage collapse, angular instability, transient voltage dip criteria violation);

4.2 The associated stability criteria used as part of determining the instability;

4.3 The associated Contingency(ies) and any Facilities critical to the instability, Cascading or uncontrolled separation;

4.4 A description of the studied System conditions when the instability, Cascading or uncontrolled separation was identified;

4.5 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

4.6 Any Corrective Action Plan associated with the instability, Cascading or uncontrolled separation.

M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator and Transmission Planner communicated the information in accordance with Requirement R4.

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 R4 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	N/A	The Planning Coordinator or a Transmission Planner used less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology, but failed to identify the exclusion criteria allowing the use of less limiting Facility Ratings.	The Planning Coordinator or a Transmission Planner 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	N/A	The Planning Coordinator or a Transmission Planner 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 technical rationale.	The Planning Coordinator or a Transmission Planner 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	N/A	The Planning Coordinator or a Transmission Planner used less limiting stability performance criteria than the stability performance criteria established in its Reliability Coordinator's SOL Methodology, but did not provide its technical rationale.	The Planning Coordinator or a Transmission Planner failed to implement a process to ensure that stability performance criteria used in Planning Assessments are equally limiting or more limiting than the stability performance criteria established in the Reliability Coordinator's SOL Methodology.
R4.	The Planning Coordinator or Transmission Planner communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator, Transmission Operator, Transmission Owner and Generator Owner, but the communication did not contain one of the elements listed in Requirement R4, Parts 4.1 – 4.6.	The Planning Coordinator or Transmission Planner communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator, Transmission Operator, Transmission Owner and Generator Owner, but the communication did not contain two of the elements listed in Requirement R4, Parts 4.1 – 4.6.	The Planning Coordinator or Transmission Planner communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator, Transmission Operator, Transmission Owner and Generator Owner, but the communication did not contain three elements listed in Requirement R4, Parts 4.1 – 4.6.	The Planning Coordinator or Transmission Planner communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator, Transmission Operator, Transmission Owner and Generator Owner, but the communication did not contain four or more of the elements listed in Requirement R4, Parts 4.1 – 4.6. OR

				The Planning Coordinator failed to communicate any identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator, Transmission Operator, Transmission Owner and Generator Owner.

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

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Implementation Plan

Project 2015-09 Establish and Communicate System Operating Limits

Applicable Standard(s) and Definitions

- ~~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
- CIP-014-3 Physical Security
- FAC-003-5 Transmission Vegetation Management
- FAC-013-3 Assessment of Transfer Capability for the Near-term Transmission Planning Horizon
- PRC-002-3 Disturbance Monitoring and Reporting Requirements
- PRC-023-5 Transmission Relay Loadability
- PRC-026-2 Relay Performance During Stable Power Swings
- Definition of System Voltage Limit in the Glossary of Terms Used in NERC Reliability Standards ("NERC Glossary")
- Definition of System Operating Limit in the NERC Glossary

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~~
- CIP-014-2 Physical Security
- FAC-003-4 Transmission ~~Planner~~Vegetation Management
- FAC-013-2 Assessment of Transfer Capability for the Near-term Transmission ~~Operator~~Planning Horizon
- PRC-002-2 Disturbance Monitoring and Reporting Requirements

- PRC-023-4 Transmission Relay Loadability
- PRC-026-1 Relay Performance During Stable Power Swings
- Currently-effective definition of System Operating Limit

Prerequisite Approvals

In addition to approval of the Reliability Standards included in this implementation plan, retirement of Reliability Standard FAC-010-3 cannot occur until the modifications in Reliability Standard CIP-002-6 (Cyber Security – BES Cyber System Categorization), Attachment 1, Criteria 2.6 and 2.9 become effective.

General Considerations

The elements of the Implementation Plans for PRC-002-2, PRC-023-4, and PRC-005-3 listed below shall remain applicable to PRC-002-3. PRC-023-5, and PRC-026-2and are incorporated herein by reference.

- Implementation of PRC-002-2 Requirements R2, R3, R4, R6, R7, R8, R9, R10, R11:
  - Entities shall be at least 50 percent compliant within four (4) years of the effective date of PRC-002-2 and fully compliant within six (6) years of the effective date.
  - Entities that own only one (1) identified BES bus, BES Element, or generating unit shall be fully compliant within six (6) years of the effective date.
- Implementation of Newly Classified Remedial Action Schemes (RAS) (PRC-023-4)
  - 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.
- Implementation of PRC-026-1
  - Requirement R1: First day of the first full calendar year that is 12 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first full calendar year that is 12 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.
  - Requirements R2, R3, and R4: First day of the first full calendar year that is 36 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first full calendar year 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.

Effective Date

The effective date for proposed Reliability Standards FAC-011-4, FAC-014-3, ~~and~~ FAC-015-1~~ and~~, CIP-014-3, FAC-003-5, FAC-013-3, PRC-002-3, PRC-023-5, PRC-026-2, and the NERC Glossary ~~term~~terms "System Voltage Limit" and System Operating 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, CIP-014-3, FAC-003-5, FAC-013-3, PRC-002-3, PRC-023-5, PRC-026-2, and the NERC Glossary ~~term~~terms "System Voltage Limit" and "System Operating 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~~terms, 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~~, CIP-014-3, FAC-003-5, FAC-013-3, PRC-002-3, PRC-023-5, PRC-026-2, the NERC Glossary ~~term~~terms "System Voltage Limit" and "System Operating 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~~terms 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~~FAC-014-2, CIP-014-2, FAC-003-4, FAC-013-2, PRC-002-2, PRC-023-4, and PRC-026-1 shall be retired immediately prior to the effective date of the proposed Reliability Standards FAC-011-4, FAC-014-3, ~~and FAC-015.~~FAC-015, CIP-014-3, FAC-003-5, FAC-013-3, PRC-002-3, PRC-023-5, PRC-026-2, and the current definition of System Operating Limit.

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.

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Implementation Plan

Project 2015-09 Establish and Communicate System Operating Limits

Applicable Standard(s) and Definitions

- 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
- CIP-014-3 Physical Security
- FAC-003-5 Transmission Vegetation Management
- FAC-013-3 Assessment of Transfer Capability for the Near-term Transmission Planning Horizon
- PRC-002-3 Disturbance Monitoring and Reporting Requirements
- PRC-023-5 Transmission Relay Loadability
- PRC-026-2 Relay Performance During Stable Power Swings
- Definition of System Voltage Limit in the Glossary of Terms Used in NERC Reliability Standards ("NERC Glossary")
- Definition of System Operating Limit in the NERC Glossary

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
- CIP-014-2 Physical Security
- FAC-003-4 Transmission Vegetation Management
- FAC-013-2 Assessment of Transfer Capability for the Near-term Transmission Planning Horizon
- PRC-002-2 Disturbance Monitoring and Reporting Requirements
- PRC-023-4 Transmission Relay Loadability
- PRC-026-1 Relay Performance During Stable Power Swings
- Currently-effective definition of System Operating Limit

Prerequisite Approvals

In addition to approval of the Reliability Standards included in this implementation plan, retirement of Reliability Standard FAC-010-3 cannot occur until the modifications in Reliability Standard CIP-002-6 (Cyber Security – BES Cyber System Categorization), Attachment 1, Criteria 2.6 and 2.9 become effective.

General Considerations

The elements of the Implementation Plans for PRC-002-2, PRC-023-4, and PRC-005-3 listed below shall remain applicable to PRC-002-3. PRC-023-5, and PRC-026-2and are incorporated herein by reference.

- Implementation of PRC-002-2 Requirements R2, R3, R4, R6, R7, R8, R9, R10, R11:
  - Entities shall be at least 50 percent compliant within four (4) years of the effective date of PRC-002-2 and fully compliant within six (6) years of the effective date.
  - Entities that own only one (1) identified BES bus, BES Element, or generating unit shall be fully compliant within six (6) years of the effective date.
- Implementation of Newly Classified Remedial Action Schemes (RAS) (PRC-023-4)
  - 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.
- Implementation of PRC-026-1
  - Requirement R1: First day of the first full calendar year that is 12 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first full calendar year that is 12 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.
  - Requirements R2, R3, and R4: First day of the first full calendar year that is 36 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first full calendar year 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.

Effective Date

The effective date for proposed Reliability Standards FAC-011-4, FAC-014-3, FAC-015-1, CIP-014-3, FAC-003-5, FAC-013-3, PRC-002-3, PRC-023-5, PRC-026-2, and the NERC Glossary terms "System Voltage Limit" and System Operating Limit" is provided below:

Where approval by an applicable governmental authority is required, Reliability Standards FAC-011-4, FAC-014-3, FAC-015-1, CIP-014-3, FAC-003-5, FAC-013-3, PRC-002-3, PRC-023-5, PRC-026-2, and the NERC Glossary terms "System Voltage Limit" and "System Operating 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 terms, 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, FAC-015-1, CIP-014-3, FAC-003-5, FAC-013-3, PRC-002-3, PRC-023-5, PRC-026-2, the NERC Glossary terms "System Voltage Limit" and "System Operating 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 terms 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, FAC-014-2, CIP-014-2, FAC-003-4, FAC-013-2, PRC-002-2, PRC-023-4, and PRC-026-1 shall be retired immediately prior to the effective date of the proposed Reliability Standards FAC-011-4, FAC-014-3, FAC-015, CIP-014-3, FAC-003-5, FAC-013-3, PRC-002-3, PRC-023-5, PRC-026-2, and the current definition of System Operating Limit.

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.

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NERC Glossary Definition: System Operating Limit

Term: "System Operating Limit"

Definition:

Redline

All Facility Ratings, System Voltage Limits, and stability limits, applicable to ~~The value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a~~ specified system configurations, used in Bulk Electric System operations for monitoring and assessing pre- and post-Contingency operating states. ~~to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:~~

~~• Facility Ratings (applicable pre- and post-Contingency Equipment Ratings or Facility Ratings)~~
~~• transient stability ratings (applicable pre- and post- Contingency stability limits)~~
~~• voltage stability ratings (applicable pre- and post-Contingency voltage stability)~~
~~• system voltage limits (applicable pre- and post-Contingency voltage limits)~~

Clean

All Facility Ratings, System Voltage Limits, and stability limits, applicable to specified System configurations, used in Bulk Electric System operations for monitoring and assessing pre- and post-Contingency operating states.

Introduction

The standard drafting team ("SDT") for *Project 2015-09 Establish and Communicate System Operating Limits* developed these rationales to explain the modifications to the definition of the term "System Operating Limit" ("SOL ") to be incorporated into the Glossary of Terms Used in NERC Reliability Standards ("NERC Glossary"). As discussed below, the purpose of the proposed modified term is to provide greater clarity and consistency with the SOL concept and how SOLs work alongside operational performance criteria to result in reliable operations.

Background

The use of SOLs is a foundational concept in NERC's Reliability Standards, as operating within SOLs for the pre- and post-Contingency state is a primary aspect of reliable Bulk Electric System ("BES") operations. An SOL is currently defined in the NERC Glossary as:

> *The value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:*
>
> - *Facility Ratings (applicable pre- and post-Contingency Equipment Ratings or Facility Ratings)*
> - *transient stability ratings (applicable pre- and post- Contingency stability limits)*
> - *voltage stability ratings (applicable pre- and post-Contingency voltage stability)*
> - *system voltage limits (applicable pre- and post-Contingency voltage limits)*

SOLs are the primary focus of FAC standards FAC-010, FAC-011, and FAC-014. Per these FAC standards:

- Planning Coordinators are required to have a methodology for establishing SOLs in its area for use in the planning horizon (FAC-010-3)
- Planning Coordinators and Transmission Planners are required to establish SOLs for use in the planning horizon consistent with the Planning Coordinator's SOL Methodology (FAC-014-2)
- Reliability Coordinators are required to have a methodology for establishing SOLs in its area for use in the operations horizon (FAC-011-3)
- TOPs are required to establish SOLs for use in the operations horizon consistent with the Reliability Coordinator's SOL Methodology (FAC-014-2)

FAC-011-3 requirement R2 states that the *"RC's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following."* The subsequent subparts to FAC-011-3 requirement R2 further describe pre-Contingency performance criteria (in R2.1), the post-Contingency performance criteria (in R2.2), and describe other rules related to the establishment of SOLs in the remaining subparts. The language in requirement R2 indicates that the SOLs established in accordance with requirement R2 are expected to "provide" a level of pre- and post-Contingency reliability described in the subparts of requirement R2. Accordingly, the assessments of the pre-Contingency state and the post-Contingency state are expected to be performed as part of the SOL establishment process, yielding a set of SOLs that "provide" for meeting the performance criteria denoted in FAC-011 R2 and subparts.

Requirements in FAC-014-2 then require the communication of those SOLs to the various operations and planning entities. TOP standards in effect at the time required TOPs to operate within these SOLs.
These FAC standards and related TOP standards established a construct for reliable operations. This SOL construct depicted in the body of Reliability Standards in effect in the 2007 timeframe is characterized by the following:

1. The TOPs and RCs would run studies for expected system conditions where the studies would examine the pre-Contingency state and the post-Contingency state.
2. If any performance criteria (in FAC-011 R2 subparts) were not being met in those studies, the TOP would establish an SOL which, if operated within, would result in all of those performance criteria being met.
3. The TOP would communicate those SOLs to System Operators.
4. The TOP System Operators would operate within those SOLs.

The TOP and IRO standards in effect prior to April 1, 2017 required TOPs to operate within these SOLs, the presumption being that if those SOLs were operated within in Real-time operations, then the acceptable pre- and post-Contingency operations criteria depicted in FAC-011-3 requirement R2 and subparts would be met.

It is important to note that prior to April 1, 2017 there were no Reliability Standards that required operational entities to perform assessments of the post-Contingency state in same-day or Real-time operations. Prior to April 1, 2017, the requirements associated with assessments of the post-Contingency state were folded into SOL establishment process – the establishment of SOLs that "provide" for meeting the documented pre- and post-Contingency performance criteria in FAC-011-3 requirement R2 and subparts.

The definition of SOL and the Reliability Standards that address SOLs – FAC-010, FAC-011, and FAC-014 – have remained essentially unchanged since their initial versions were approved and adopted in 2007. Since that time, many improvements have been made to the body of reliability standards, specifically those in the TPL, TOP, and IRO family of standards. The former TPL-001, -002, -003, and -004 Reliability Standards have been replaced with TPL-001-4, all of the TOP standards were replaced with the currently effective TOP-001, TOP-002, and TOP-003, and several IRO standards have been replaced as well. The definition of SOL and the FAC standards that address SOLs are inextricably linked to many of the TPL, TOP, and IRO standards, as they all address in some manner the foundational reliability concept of acceptable system performance. One of the primary objectives of Project 2015-09 is to make changes to the SOL definition and the related FAC standards to create better alignment with the currently effective TPL, TOP, and IRO standards. The SDT's proposal to revise the definition of SOL improves clarity, reduces redundancy, and creates better alignment and continuity with the currently effective TOP and IRO standards.

Due to changes in the TOP and IRO Reliability Standards that became effective on April 1, 2017, this SOL construct described by the currently effective definition of SOL and the manner in which it is used in the FAC standards is not reflective of the construct encapsulated in the operational requirements in place

today. The new TOP and IRO standards represent a new construct for managing reliability for the pre- and post-Contingency state. Under this new construct approved in Order No. 817[1]:

1. TOPs and RCs are required to ensure that an Operational Planning Analysis (OPA) is performed to assess whether the planned operations for the next-day will exceed any of its SOLs and IROLs[2]. The pre- and post-Contingency states are analyzed as part of the OPA.[3]
2. If the OPA identifies any potential exceedances, the RC and TOP must have an Operating Plan to address the exceedance.[4]
3. In Real-time, RCs and TOPs must perform Real-time Assessments (RTAs) at least once every 30 minutes to determine whether there are any expected or actual exceedances of SOLs (including IROLs) based on Real-time conditions.[5] The pre- and post-Contingency states are analyzed as part of the RTA.[6]
4. If SOL exceedances are observed in TOP Real-time monitoring or RTAs, TOPs are required to implement its Operating plan to mitigate the conditions.[7]
5. If SOL or IROL exceedances are observed in RC Real-time monitoring or RTAs, RCs are required to notify TOPs of those exceedances.[8]
6. If there is an expected or actual IROL exceedance identified in RC Real-time monitoring or RTAs, the exceedance must be resolved within the IROL T_v, which can be no longer than 30 minutes.[9]

Pursuant to the construct in the currently-effective TOP/IRO Reliability Standards, TOPs and RCs must assess system conditions, identify expected or actual SOL exceedances (including for the subset of SOLs designated as IROLs) and take steps to address any such exceedances to avoid the possibility of further deterioration in system conditions. Under this new construct, the pre- and post-Contingency states are assessed on an ongoing basis as part of OPAs and RTAs. Any SOL exceedances that are observed are required to be mitigated per the respective Operating Plans. Under this new construct, it is the OPA, the RTA, and the implementation of Operating Plans that "provide" for reliable pre- and post-Contingency operations. In the former construct, operating within the TOP-provided SOL "provided" for reliable pre- and post-Contingency

[1] *Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards*, Order No. 817, 153 FERC ¶ 61,178 (2015).

[2] IRO-008-2, Requirement R1; TOP-004-2, Requirement R1.

[3] OPA – 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.)

[4] IRO-008-2, Requirement R2; TOP-004-2, Requirement R2.

[5] IRO-008-2, Requirement R4; TOP-001-3, Requirement R13.

[6] RTA – 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.)

[7] TOP-001-3 requirement, Requirement R14

[8] IRO-008-2 requirement, Requirement R5

[9] IRO-009-2, Requirements R1-R4; TOP-001-3, Requirement R12.

operations. The proposed revised FAC standards and the proposed revised SOL definition is intended to reflect the new construct depicted in the TOP and IRO standards.

NERC SOL Whitepaper

As discussed in the whitepaper prepared by the SDT for Project 2014-03 Revisions to TOP and IRO Standards (the "Project 2014-03 Whitepaper"), which developed the currently-effective Transmission Operations ("TOP") and Interconnection Reliability Operations and Coordination ("IRO") Reliability Standards, while the term SOL is used extensively in the NERC Reliability Standards, there is significant confusion with, and many widely varied interpretations and applications of, the term SOL. While the Project 2014-03 SDT did not seek to modify the SOL definition, they drafted the Project 2014-03 Whitepaper to describe their understanding of the SOL term/concept and to "bring clarity and consistency to the notion of establishing SOLs, exceeding SOLs, and implementing Operating Plans to mitigate SOL exceedances." The Project 2014-03 Whitepaper served as the conceptual basis for the development of the currently-effective TOP/IRO Reliability Standards.

As described in the Project 2014-03 Whitepaper, the central principles of the SOL concept in NERC's Reliability Standards is to:

1. Know the Facility Ratings, voltage limits, transient Stability limits, and voltage Stability limits, and
2. Ensure that they are all observed in both the pre- and post-Contingency state by performing a Real-time Assessment.

These principles are reflective of the new construct for managing reliability for the pre- and post-Contingency state depicted in the TOP and IRO standards created as part of Project 2014-03.

Following the development of the currently-effective TOP/IRO Reliability Standards, NERC initiated a periodic review of the requirements in the Facilities Design, Connections, and Maintenance ("FAC") group of Reliability Standards addressing SOLs. The periodic review team identified a need to revise or develop new definitions to be incorporated into the NERC Glossary to provide greater clarity and consistency in establishing SOLs and promote a common understanding of what it means to exceed SOLs. The periodic review team recognized that while the project 2014-03 Whitepaper provided clarity on the SOL concept, reliability would be further enhanced by (1) revising the SOL definition in the NERC Glossary, and (2) developing a new defined term SOL Exceedance. The periodic review envisioned that these two enhancements help to better align the definitions in the NERC Glossary with the Project 2014-03 Whitepaper and better support the SOL exceedance concept used in the TOP/IRO Reliability Standards. Subsequently, to address the issues identified in the periodic review, NERC initiated Project 2015-09 to revise the requirements for, and definitions related to, the methodology used for establishing and communicating SOLs.

In September of 2017 the standard drafting team posted a proposed definition of SOL Exceedance for informal comment. The industry responses to the draft SOL Exceedance definition indicated numerous significant concerns. Given these responses, the SDT concluded that creating a definition of SOL Exceedance that adequately reflected reliable operating principles could create too much of an unnecessary compliance burden without significant modification to the existing TOP and IRO standards. Therefore, the SDT

abandoned the idea of creating a definition for SOL Exceedance in favor of addressing the performance criteria through requirements in FAC-011-4 and FAC-014-3 similar to the way it is done in the currently effective FAC standards.

Modifications to SOL Definition

The Project 2015-09 SDT proposes to define the term System Operating Limit (SOL) as:

> *All Facility Ratings, System Voltage Limits, and stability limits, applicable to specified System configurations, used in Bulk Electric System operations for monitoring and assessing pre- and post-Contingency operating states.*

The SDT's intent was to simplify and clarify the SOL definition by eliminating ambiguities such that SOLs are easily identifiable and easily measurable. The currently-effective SOL definition states that SOLs "are based upon certain operating criteria." The modified definition eliminates the phrase "are based upon" to more accurately state that the SOLs "are" the actual operating parameters which are to be observed for the pre- and post-Contingency states, leaving no confusion as whether a Facility Rating, stability limit, or voltage limit is an SOL. The unambiguous language in the modified definition should help facilitate a more consistent application of the SOL concept within the electric industry.

Facility Ratings, System Voltage Limits, and stability limits are the three types of operating criteria included in the existing SOL definition and carried forward into the modified definition that must be accounted for to ensure reliable operations. Facility Ratings must be established in accordance with Reliability Standard FAC-008-3. System Voltage Limits, as discussed below, is proposed to be defined as "the maximum and minimum steady-state voltage limits (both normal and emergency) that provide for acceptable System performance." Stability limits includes both transient stability limits and voltage stability limits. The intent of using the "stability limit" term (as opposed to the NERC Glossary term "Stability Limit") is to allow for a number of different types of stability-related limitations or phenomena, including, but not limited to, sub-synchronous resonance (SSR), phase angle limitations, transient voltage limitations on equipment, and weighted short-circuit ratio (WSCR). The Glossary term "Stability Limits" is not appropriate for use in the revised definition because its use is limited to a maximum power flow value. While some entities may use maximum power flow values as a means by which to prevent instability, this approach represents only one particular method and may be too restrictive for some entities. Reliability tools allow entities to monitor and control parameters other than maximum power flow values in order to demonstrate acceptable stability performance.

Unlike the existing SOL definition, the proposed definition includes the phrase "used in Bulk Electric System operations" to distinguish those Facility Ratings, voltage limits, and stability limits that are used in planning. The SDT determined that the SOL concept should be limited to the operational time horizon and thus proposes to retire FAC-010-3. The Facility Ratings, voltage limits, and stability criteria used in the planning horizon are developed according to FAC-008-3 and TPL-001-4 and, as a result, there was no additional reliability need to require Planning Authorities to develop SOLs to be used in the planning horizon. The SDT concluded, however, that there was a reliability need to coordinate the Facility Ratings, voltage limits, and

stability criteria used in planning with those used in operations. The SDT developed proposed Reliability Standard FAC-015-1 to address that issue.

As discussed in detail below, the SDT determined that references to "most limiting criteria" and "acceptable reliability criteria", and the manner in which the "specified system configuration" and the "pre- and post-contingency" phrases were used in the currently-effective definition of SOL were adding to industry confusion as to what constitutes an SOL.

Most limiting Criteria – The SDT concluded that removing the "most limiting criteria" concept in favor of designating all Facility Ratings, System Voltage Limits, and stability limits as SOLs is better aligned with the requirements in the TOP/IRO Reliability Standards. As noted above, under the TOP/IRO Reliability Standards, each RC and TOP must perform Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs) to assess conditions in the day ahead and Real-time horizon and, if it identifies any actual, expected or potential SOL exceedance, take appropriate mitigating action to maintain pre- and post-Contingency reliable operations. Under the currently-effective SOL definition, RCs and TOPs must initially determine which operating parameter is the most limiting at that point in time to be designated as the SOL and then determine if there are any actual, potential, or expected exceedances of that SOL. The SDT understands that this has caused some confusion within industry. Specifically, it may be unclear in Real-time operations when an SOL ceases to be an SOL because it is no longer the "most limiting criteria." Confusion is introduced when the most limiting criteria (and thus the SOL) changes from one RTA to the next.

The SDT determined that it is more straightforward to simply categorize all Facility Ratings, System Voltage Limits, and stability limits as SOLs. In performing OPAs and RTAs, RCs and TOPs should be assessing conditions as it relates to any operating parameter or reliability limit, not the most limiting parameter or limit based on a particular prior analysis. Under the new TOP and IRO requirements, RCs and TOPs are assessing conditions on an ongoing basis through OPAs and RTAs to determine whether there are any actual, potential, or expected exceedances of any Facility Rating, System Voltage Limit, or stability limit, which would necessarily include the most limiting of those parameters/limits. In this manner, the "most limiting criteria" concept is subsumed within the requirements of the TOP/IRO Reliability Standards and it is not necessary that it be included in the SOL definition. In short, the proposed SOL definition creates a simplified approach. There is no need to continuously identify and communicate the ever-changing "most limiting" criteria. Entities must simply operate – and plan to operate – to prevent any exceedance of all Facility Ratings, System Voltage Limits, and stability limits.

The SDT determined that the removal of the "most limiting criteria" from the SOL definition represents an improvement to reliability. The "most limiting criteria" can adversely impact reliability by masking instability risks that may exist slightly beyond the point of the most limiting condition. To illustrate, where prior studies indicate that a thermal limitation is the "most limiting criteria," if the studying entity does not study the performance of the system appreciably beyond this thermal limitation to reasonably expected stressed conditions, it cannot be safely concluded that a more significant instability risk does not exist slightly beyond the point where the "most limiting criteria" exists. Because actions may be taken in the actual system conditions that mitigate thermal and voltage limitations identified as a "most limiting criteria", it may be necessary to identify where subsequent operation may approach a point of instability. Consistent with this

concept, the RC and its TOPs have the responsibility of establishing stability limits in accordance with the Reliability Coordinator's SOL Methodology, as required by FAC-011-4 Requirement R4 and FAC-014-3 Requirements R2 and R4.

Acceptable Reliability Criteria – The SDT determined that the "acceptable reliability criteria" concept is best addressed through requirement language and that the SOL definition should focus simply on what constitutes an SOL. Taken together, the operations performance criteria in FAC-011-4 requirement R6 and the corresponding requirement R7 in FAC-014-3 adequately addresses operation within acceptable reliability criteria.

Specified System Configuration – The SDT proposes to retain the reference to "specified system configuration" due to the fact that stability limits in particular are typically dependent on system configuration. While Facility Ratings and System Voltage Limits are not typically dependent upon system configuration, there may be times where they may be dependent on System configuration. For example, if a transmission line is connected by two circuit breakers at one end of the line, and one of those two circuit breakers is open, the value of the Facility Rating for line could be reduced due to current carrying capability of the remaining in-service circuit breaker.

Pre- and Post-Contingency – The currently effective SOL definition specifies that each of the listed operating limit types are applicable for both the pre- and post-Contingency states. The SDT determined that the pre- and post-Contingency concept needed to be retained; however, it should be used in a manner consistent with the construct depicted in the new TOP and IRO standards rather than the old construct where the SOL itself "provided" for pre- and post-Contingency acceptable performance. The proposed definition makes it clear that both the pre-Contingency state and the post-Contingency state must be considered when evaluating the System performance for Facility Ratings, System Voltage Limits, and stability limits. As OPAs and RTAs are the mechanisms in the Reliability Standards for determining potential SOL exceedances (OPA) and actual SOL exceedances (RTA),[10] the definition of SOL should support the concept that both the pre- and post-Contingency states should be accounted for.

One aspect of the improved clarity of the revised definition of SOL is seen in its intended use. Under the revised definition, SOLs are intended to be used as an input into the OPA and RTA process.[11] The OPA and RTA process itself examines SOLs for the pre- and post-Contingency states and determines whether the SOLs are being exceeded. Accordingly, while SOLs are an input to the OPA and RTA process, SOL exceedance is the output of the OPA and RTA process. FAC-014-3 requirement R7 effectively stipulates that the operations performance criteria denoted in FAC-011-4 requirement R6 must be used in OPAs, RTAs, and Real-time monitoring when identifying SOL exceedances.

[10] In Order No. 705 (at P 162), the Commission stated that system performance is determined through studies, stating "the Commission believes that to demonstrate the pre- and post-contingency performance metrics required by [FAC-010-1] Requirements R2.1-R2.2 an assessment or analysis would need to be performed. As such, Requirements R2.1-R2.2 provide for actions that go beyond NERC's characterization of the subject of the requirements as limited to a list of topics that must be included in a methodology. Therefore, we conclude that these Requirements are more Docket No. RM07-3-000 - 79 - properly treated as implementation or operational requirements that may have a direct impact on reliability."

[11] Some Reliability Coordinators and Transmission Operators may establish stability limits in the context of an OPA or RTA. For entities who adopt this approach, the stability SOL would be established – and its exceedance determined – as part of the OPA or RTA.

Lastly, as with the currently-effective SOL definition, the proposed SOL definition does not include reference to IROLs. IROLs, as currently defined, are a subset of SOLs that, if exceeded, "could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the BES." The determination of when an SOL should be designated as an IROL is most appropriately addressed in the RC's SOL methodology. There is no need to mention IROLs in the definition of SOL.

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CIP SDT Outreach Slides

Project 2016-02 Project Update

CIP SDT Members
April 2019

RELIABILITY | ACCOUNTABILITY

Agenda

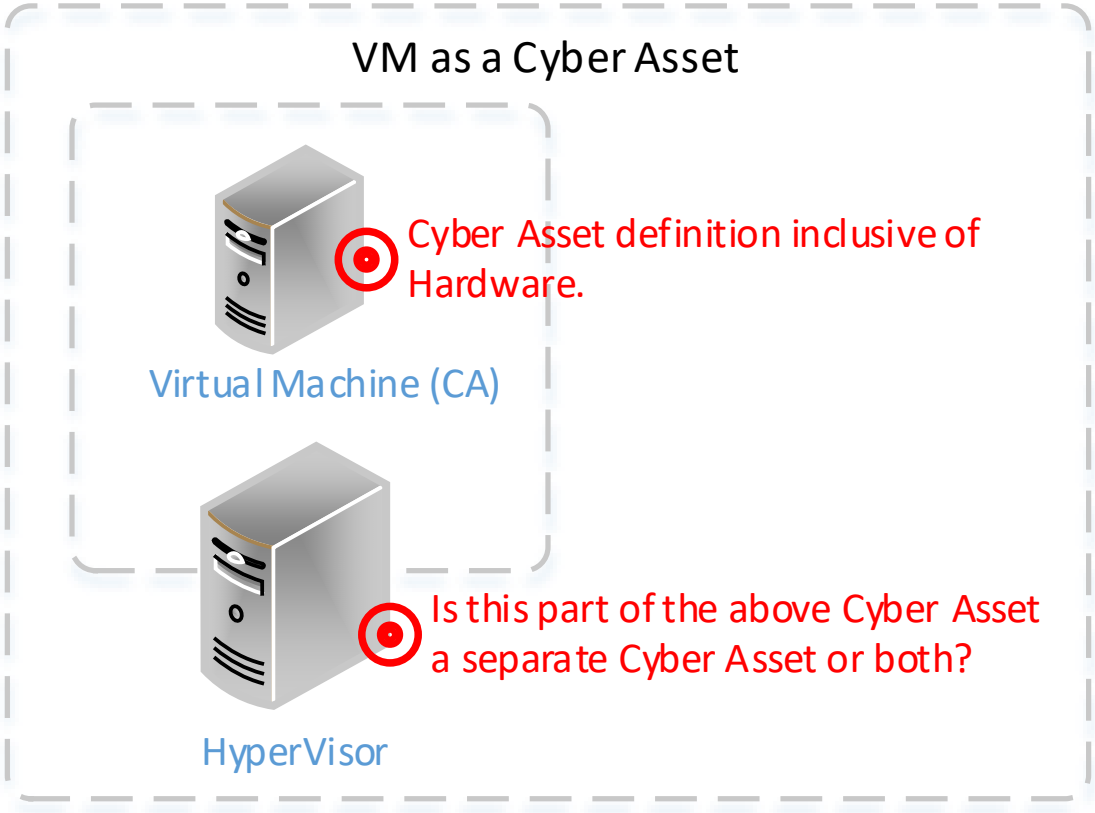
- Why
  - Many Challenges
- What we Heard
- How we can move forward

Why

- CIP v5 Technology Specific
  - Cyber Assets (inclusive of hardware 1:1)
  - Prescribed network architecture restricts best practices
- Virtualization Challenges
  - Virtualized Firewall Interfaces
  - Storage
  - Remediation VLANs
  - Super ESP

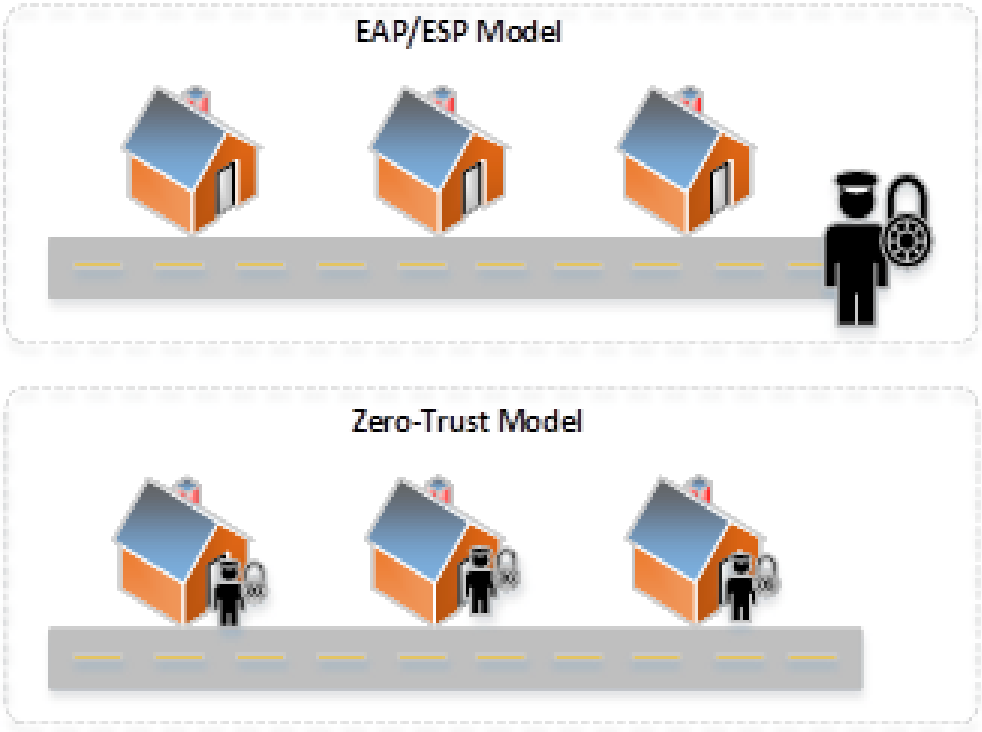
Many Challenges – Asset Identification

- Virtual Cyber Assets (inclusive of hardware 1:1)
- Treating VMs as a Cyber Asset creates the “hall of mirrors” because Cyber Asset is inclusive of its hardware



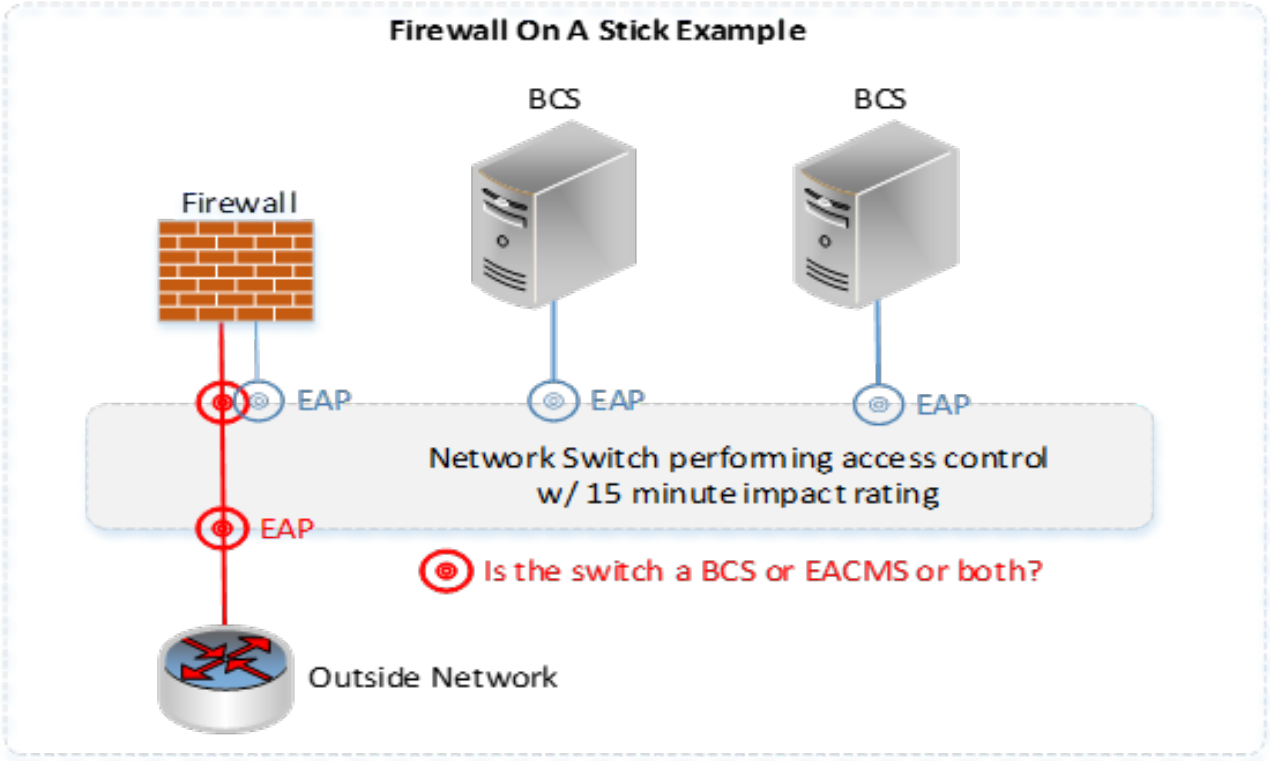
Many Challenges – Network Architecture

- Prescribed Network Architecture



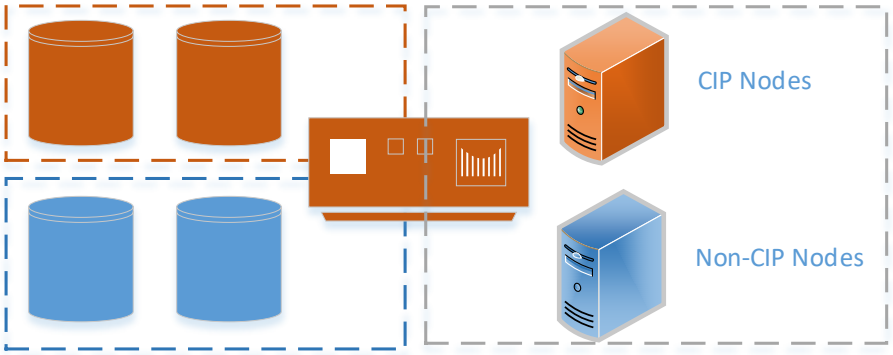
Many Challenges – Virtualized Firewall Interfaces

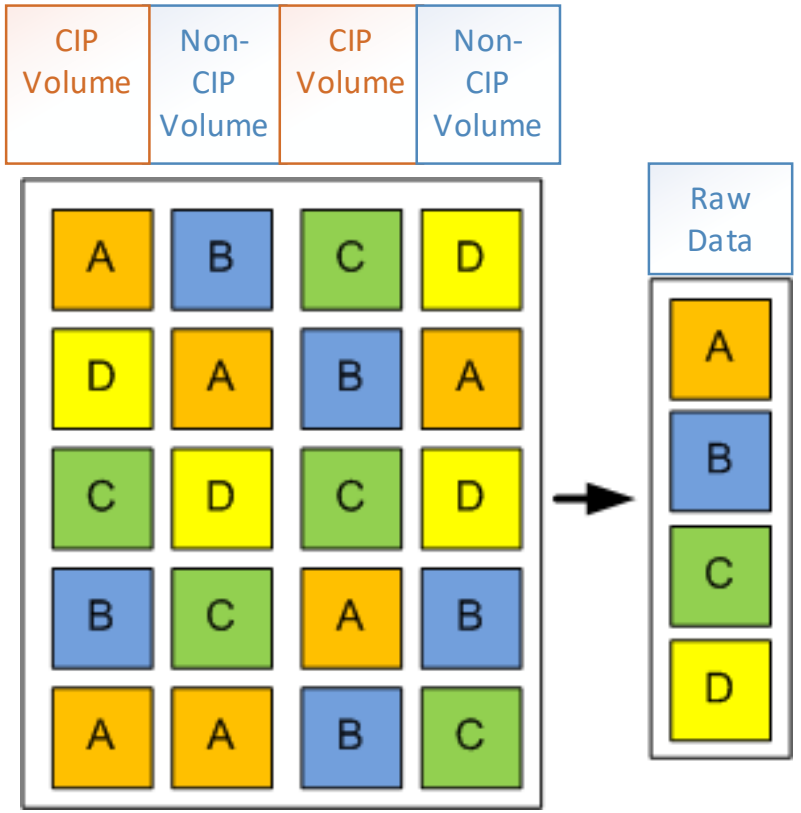
- Virtualized Firewall Interfaces ('Firewall on a Stick')



Many Challenges - Storage

- SAN/NAS deduplication & sanitization

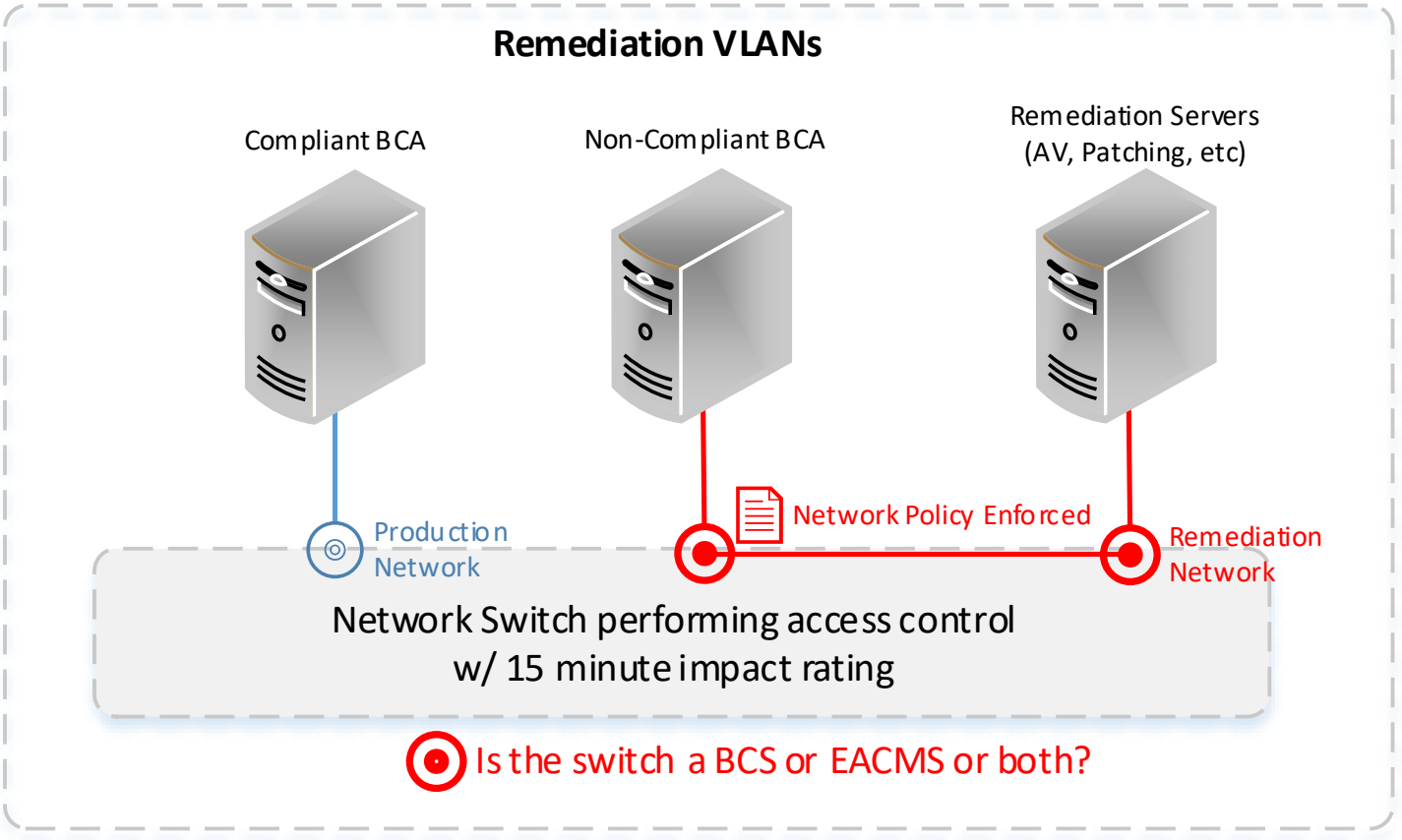




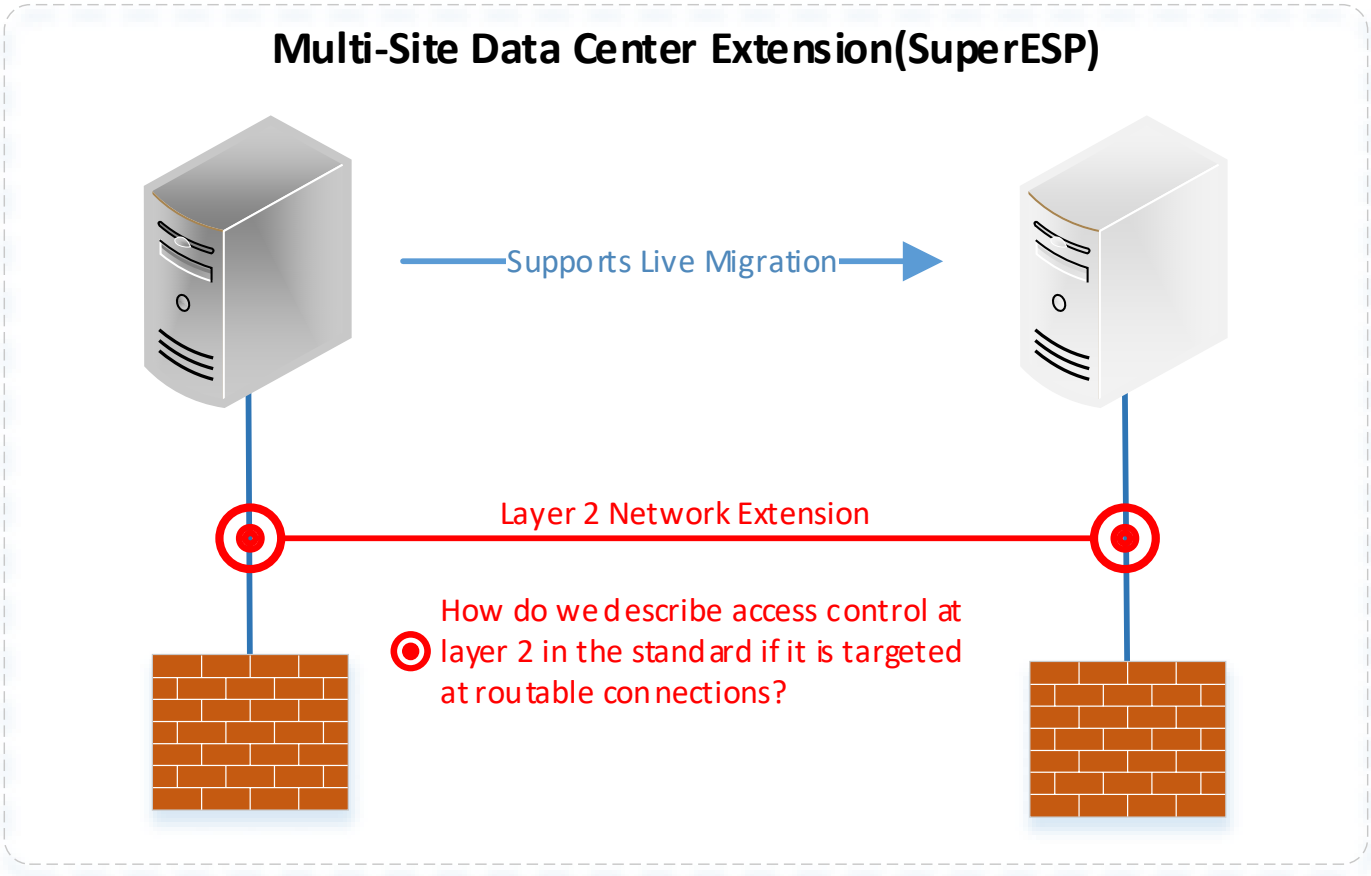
Deduplication Example

Many Challenges - Remediation

- Remediation VLANs



Many Challenges – Super ESP



Q&A – Current State

What We Heard

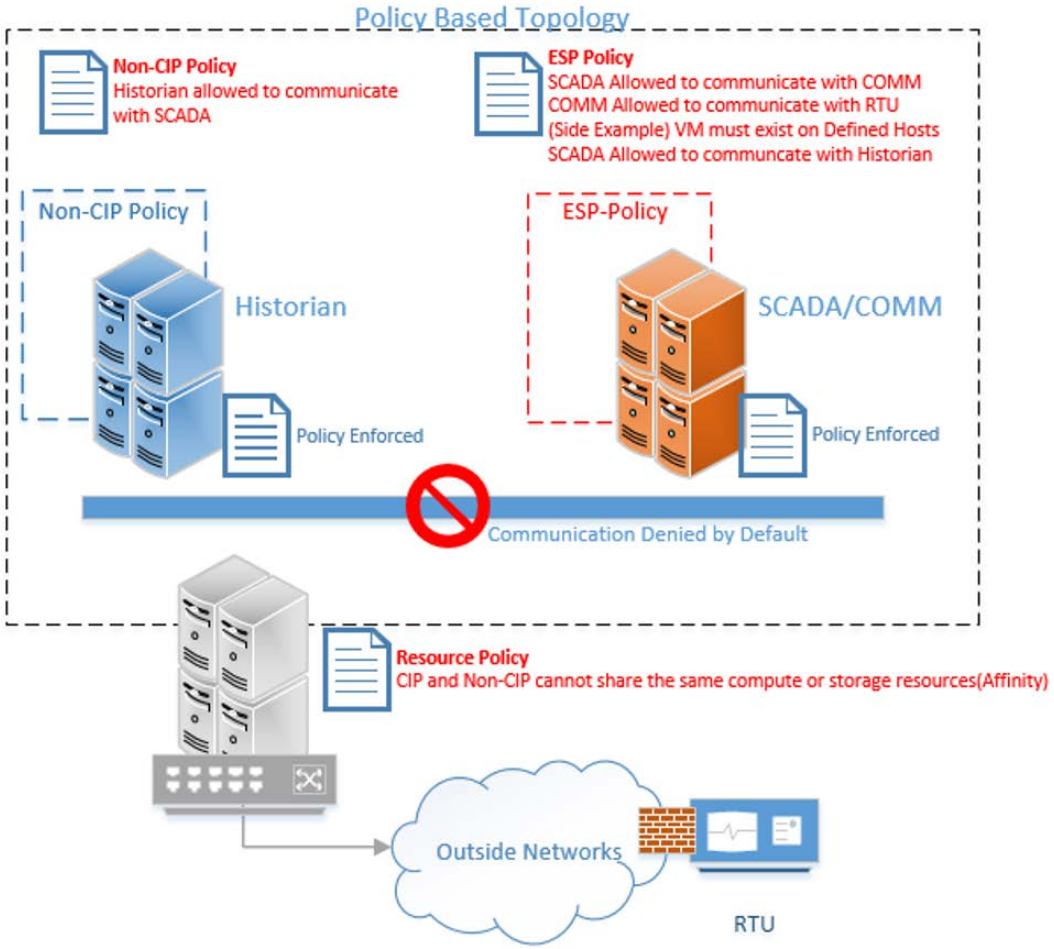
- Why change?
- Removed the “programmable” floor
- Other options to deal with virtualization
- LIZ vs. ESP
- Objective language level and clarity
- Secure Configuration scope expansion and use
- ERC as a scoping mechanism

What is the Goal?

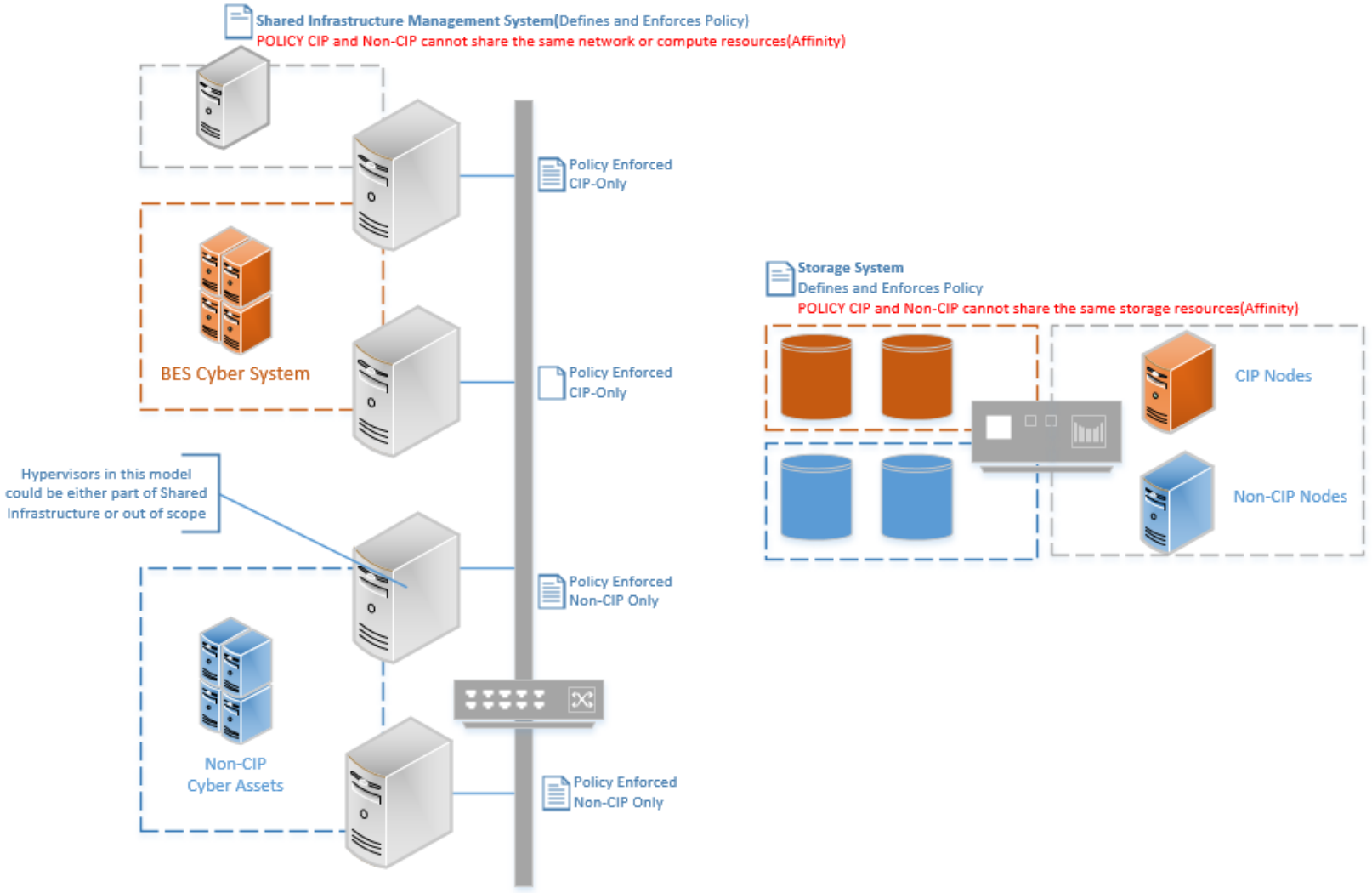
- Stabilize the standards
- To provide clarity for virtualization within the standards
- Encourage security best practices

What is the Goal?

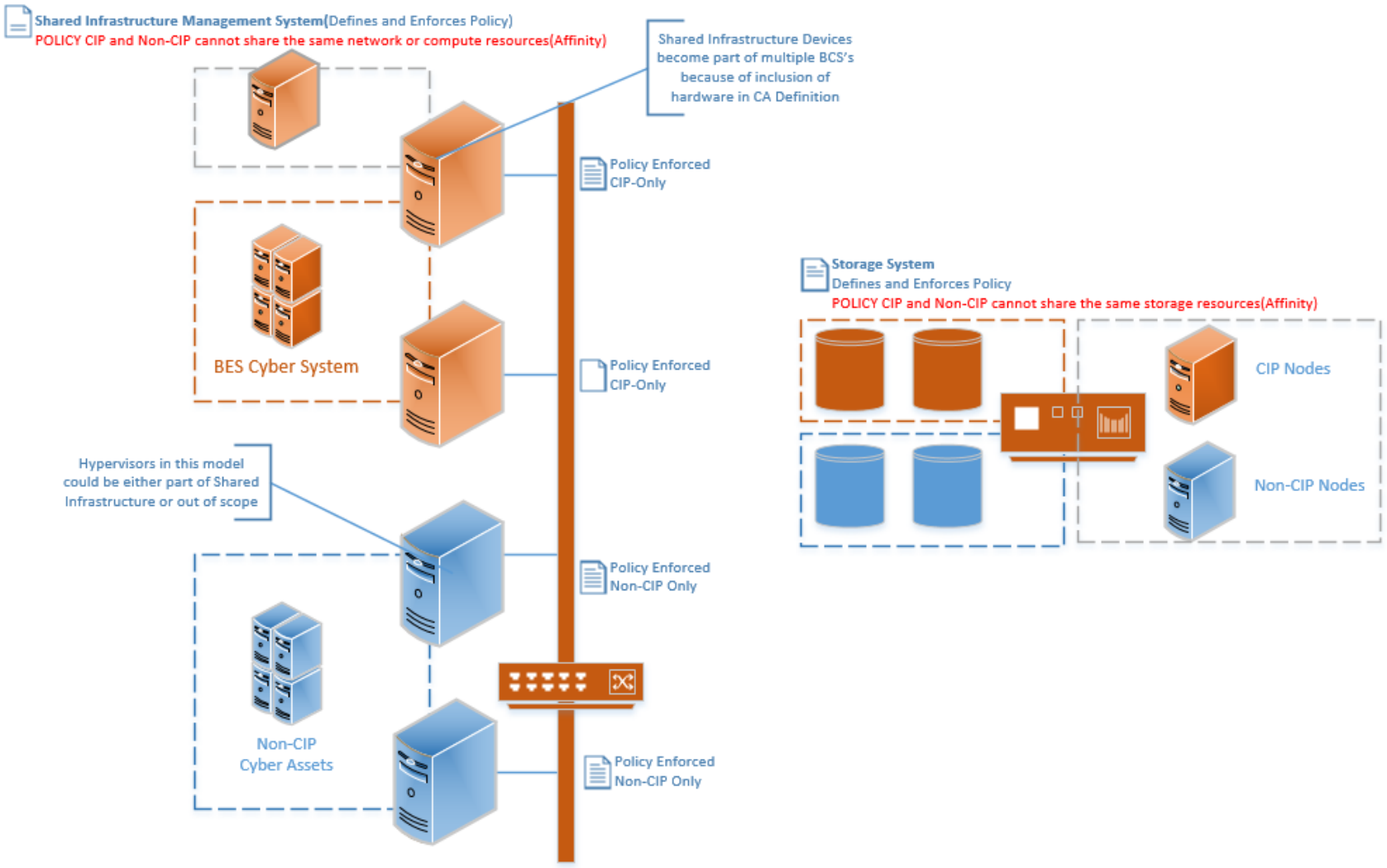
- Environments like this and many others are allowed and compliant



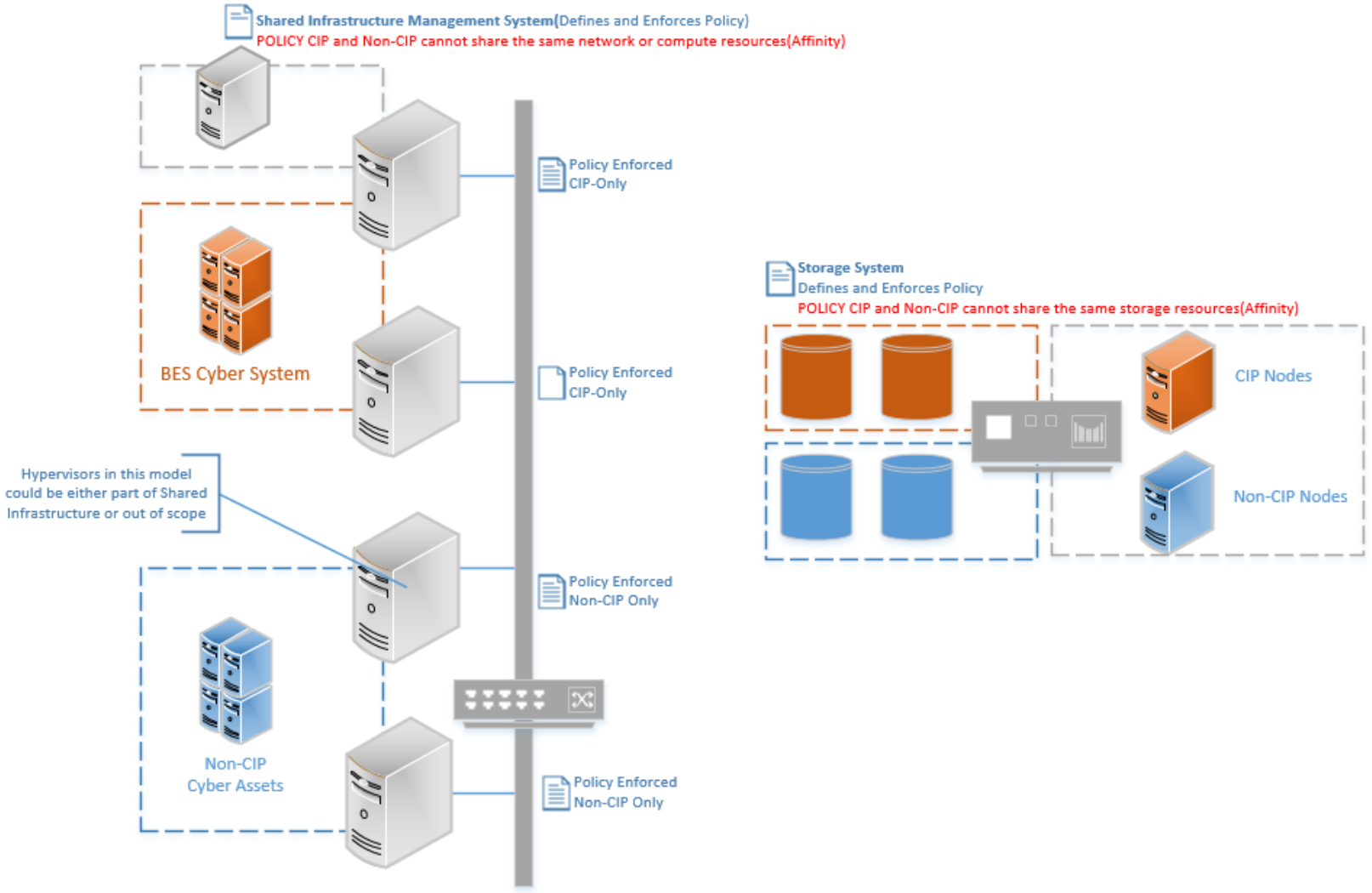
What is the Goal?



What is the Goal?



What is the Goal?

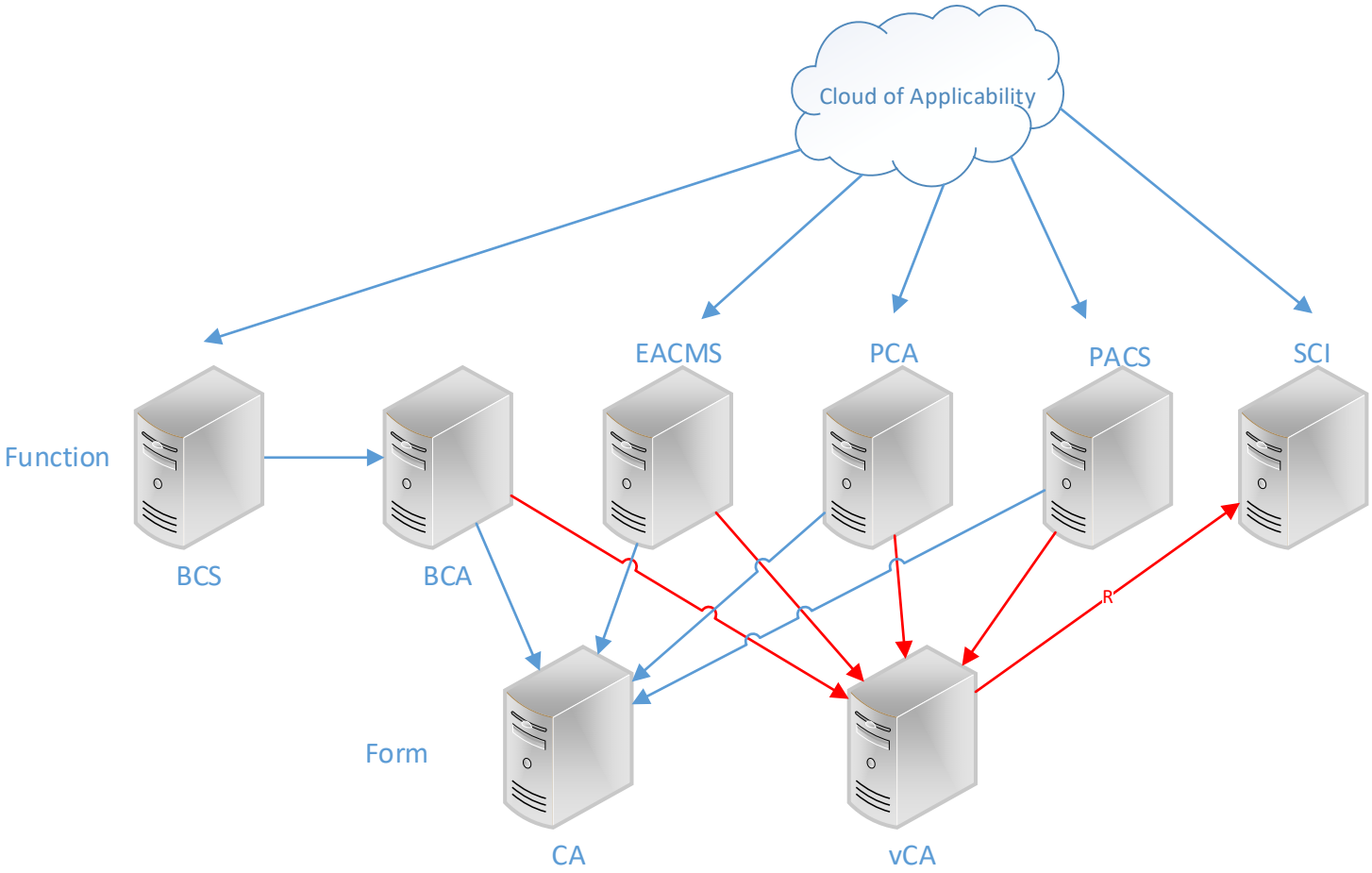


How We Can Move Forward

- **Virtual Cyber Asset (vCA):** A simulated environment that is hosted on Shared Cyber Infrastructure.

- **Shared Cyber Infrastructure:** Cyber Assets whose compute, storage, or network resources are shared with Virtual Cyber Assets. This includes the centralized management components of the Shared Infrastructure.

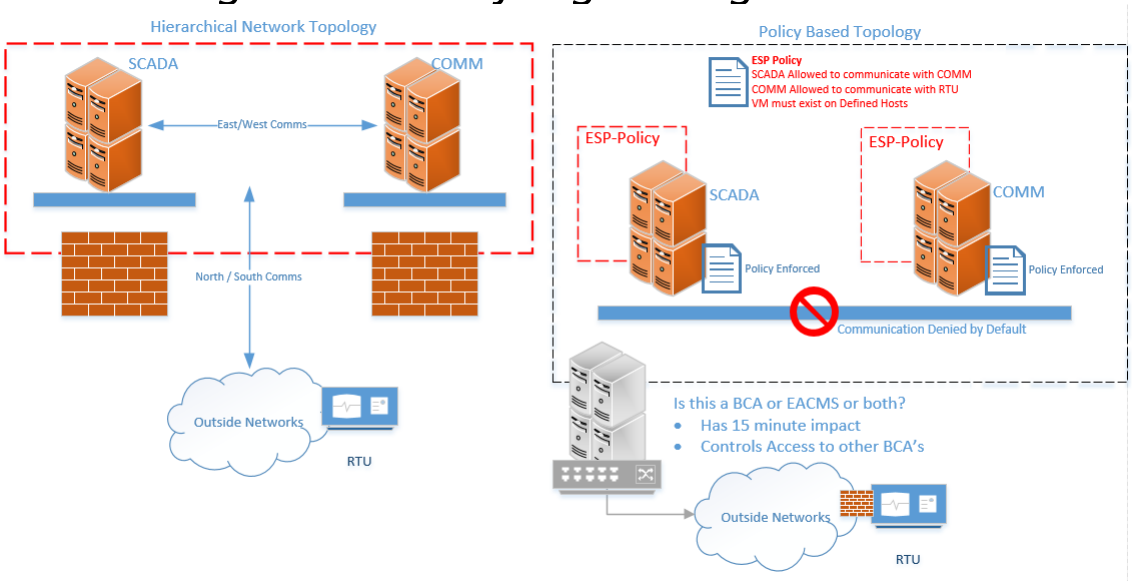
How We Can Move Forward



How We Can Move Forward

- An example of an objective requirement that clearly describes a measurable "what" but avoids prescriptive "how's" for CIP-005 R1 could conceptually be:

  "Deny all access to and from the networks on which high and medium impact BES Cyber Systems and their associated PCAs are connected and only allow network communication that has documented access permissions including the reason for granting access."



How We Can Move Forward

- Move toward technology agnostic requirements.
- New terms to help describe the virtual environment.
  - Clarify new requirements for the virtual environment.
- Preserve Cyber Asset term for backwards compatibility.

Next Steps

- Continue Virtualization Standard Drafting Efforts:
  - May 21-23, 2019 in-person CIP SDT meeting – ERCOT
  - June 25-27, 2019 in-person CIP SDT Meeting – Tacoma Power

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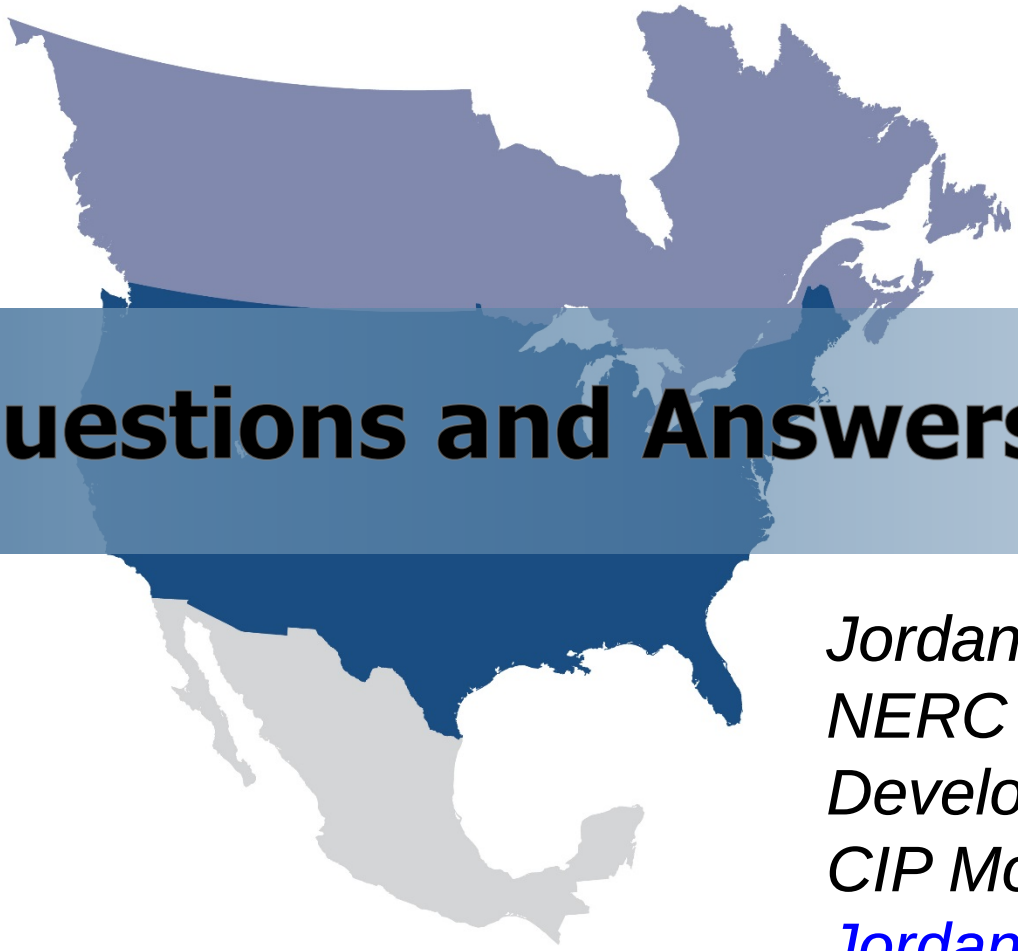

Questions and Answers

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NERC
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CIP Definitions

Project 2016-02 Modifications to CIP Standards
October 29, 2018, Informal Posting

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.

Table 1: Retired, Modified, or Newly Proposed Definitions

NERC Glossary Term	Currently Approved Definition	CIP SDT Proposed New or Revised
Cyber Asset (CA)	Programmable electronic devices, including the hardware, software, and data in those devices.	A p~~P~~rogrammable electronic device~~s~~, including the physical or virtual hardware, software, and data in th~~os~~e device~~s~~.
BES Cyber System (BCS)	One or more BES Cyber Assets logically grouped by a responsible entity to perform one or more reliability tasks for a functional entity.	Any combination of hardware (including virtual hardware), software (including application virtualization), and data, regardless of redundancy, performing one or more reliability tasks that if rendered unavailable, degraded, or misused would result in adverse impact to one or more BES Facilities within 15 minutes.

Table 1: Retired, Modified, or Newly Proposed Definitions		
NERC Glossary Term	**Currently Approved Definition**	**CIP SDT Proposed New or Revised**
BES Cyber Asset (BCA)	A Cyber Asset that if rendered unavailable, degraded, or misused would, within 15 minutes of its required operation, misoperation, or non-operation, adversely impact one or more Facilities, systems, or equipment, which, if destroyed, degraded, or otherwise rendered unavailable when needed, would affect the reliable operation of the Bulk Electric System. Redundancy of affected Facilities, systems, and equipment shall not be considered when determining adverse	Retired

Table 1: Retired, Modified, or Newly Proposed Definitions		
NERC Glossary Term	**Currently Approved Definition**	**CIP SDT Proposed New or Revised**
Transient Cyber Asset (TCA)	A Cyber Asset that is: 1. capable of transmitting or transferring executable code, 2. not included in a BES Cyber System, 3. not a Protected Cyber Asset (PCA) associated with high or medium impact BES Cyber Systems, and 4. directly connected (e.g., using Ethernet, serial, Universal Serial Bus, or wireless including near field or Bluetooth communication) for 30 consecutive calendar days or less to a: • BES Cyber Asset, • network within an Electronic Security Perimeter (ESP) containing high or medium impact BES Cyber Systems, or • PCA associated with high or medium impact BES Cyber Systems. Examples of Transient Cyber Assets include, but are not limited to, Cyber Assets used for data transfer, vulnerability assessment, maintenance, or troubleshooting purposes.	A Cyber Asset that is: 1. capable of transmitting or transferring executable code, 2. not included in a BES Cyber System, 3. not a Protected Cyber ~~Asset~~ System (PC~~S~~A) associated with high or medium impact BES Cyber Systems, and 4. directly connected (e.g., using Ethernet, serial, Universal Serial Bus, or wireless including near field or Bluetooth communication) for 30 consecutive calendar days or less to a: • BES Cyber ~~Asset~~System (BCS), • ~~network within an~~ A BES Cyber System Logical Isolation Zone ~~Electronic Security Perimeter (ESP)~~ containing high or medium impact BES Cyber Systems, or • PC~~S~~A associated with high or medium impact BES Cyber Systems. Examples of Transient Cyber Assets include, but are not limited to, Cyber Assets used for data transfer, vulnerability assessment, maintenance, or troubleshooting purposes.

Table 1: Retired, Modified, or Newly Proposed Definitions		
NERC Glossary Term	**Currently Approved Definition**	**CIP SDT Proposed New or Revised**
Physical Access Control Systems (PACS)	Cyber Assets that control, alert, or log access to the Physical Security Perimeter(s), exclusive of locally mounted hardware or devices at the Physical Security Perimeter such as motion sensors, electronic lock control mechanisms, and badge readers.	Cyber systems ~~Assets~~ that control~~, alert, or log~~ access to the Physical Security Perimeter(s), exclusive of locally mounted hardware or devices at the Physical Security Perimeter such as motion sensors, electronic lock control mechanisms, and badge readers.
Physical Access Monitoring Systems (PAMS)	N/A	Cyber systems that alert or log access to the Physical Security Perimeter(s), exclusive of locally mounted hardware or devices at the Physical Security Perimeter such as motion sensors, electronic lock control mechanisms, and badge readers.
Protected Cyber Asset (PCA)	One or more Cyber Assets connected using a routable protocol within or on an Electronic Security Perimeter that is not part of the highest impact BES Cyber System within the same Electronic Security Perimeter. The impact rating of Protected Cyber Assets is equal to the highest rated BES Cyber System in the same ESP.	Retired
Protected Cyber System (PCS)	N/A	Cyber systems that are able to communicate with a BES Cyber System from within the BES Cyber System's Logical Isolation Zone. The impact rating of Protected Cyber Systems is equal to the highest rated BES Cyber System within the Logical Isolation Zone.

Table 1: Retired, Modified, or Newly Proposed Definitions		
NERC Glossary Term	**Currently Approved Definition**	**CIP SDT Proposed New or Revised**
Electronic Access Point (EAP)	A Cyber Asset interface on an Electronic Security Perimeter that allows routable communication between Cyber Assets outside an Electronic Security Perimeter and Cyber Assets inside an Electronic Security Perimeter.	Retired
Electronic Access Control or Monitoring Systems (EACMS)	Cyber Assets that perform electronic access control or electronic access monitoring of the Electronic Security Perimeter(s) or BES Cyber Systems. This includes Intermediate Systems.	RETIRED – Proposed Develop EAMS and EACS
Electronic Access Control System (EACS)	N/A	Cyber systems that provide electronic access control to BES Cyber Systems.
Electronic Access Monitoring Systems (EAMS)	N/A	Cyber systems that provide electronic access monitoring of BES Cyber Systems.
Electronic Security Perimeter (ESP)	The logical border surrounding a network to which BES Cyber Systems are connected using a routable protocol.	Retired
External Routable Connectivity (ERC)	The ability to access a BES Cyber System from a Cyber Asset that is outside of its associated Electronic Security Perimeter via a bi-directional routable protocol connection.	The ability to access a BES Cyber System from a Cyber Asset that is outside of its associated Logical Isolation Zone via a bi-directional routable protocol connection.

Table 1: Retired, Modified, or Newly Proposed Definitions		
NERC Glossary Term	**Currently Approved Definition**	**CIP SDT Proposed New or Revised**
Logical Isolation Zone (LIZ)	N/A	A logical security zone created by applying controls to communications to or from BES Cyber Systems and Protected Cyber Systems.
Intermediate Systems (IS)	A Cyber Asset or collection of Cyber Assets performing access control to restrict Interactive Remote Access to only authorized users. The Intermediate System must not be located inside the Electronic Security Perimeter.	A system acting as part of the protection applied to a logically isolated BCS that limits external user-initiated access to authorized users.
Interactive Remote Access (IRA)	User-initiated access by a person employing a remote access client or other remote access technology using a routable protocol. Remote access originates from a Cyber Asset that is not an Intermediate System and not located within any of the Responsible Entity's Electronic Security Perimeter(s) or at a defined Electronic Access Point (EAP). Remote access may be initiated from: 1) Cyber Assets used or owned by the Responsible Entity, 2) Cyber Assets used or owned by employees, and 3) Cyber Assets used or owned by vendors, contractors, or consultants. Interactive remote access does not include system-to-system process communications.	User-initiated access by a person employing a remote access client to a BES Cyber System or Protected Cyber System from outside of a Logical Isolation Zone. Interactive Remote Access does not include system-to-system process communications or access initiated from an Intermediate System.

Table 1: Retired, Modified, or Newly Proposed Definitions		
NERC Glossary Term	**Currently Approved Definition**	**CIP SDT Proposed New or Revised**
Physical Security Perimeter (PSP)	The physical border surrounding locations in which BES Cyber Assets, BES Cyber Systems, or Electronic Access Control or Monitoring Systems reside, and for which access is controlled.	The physical border surrounding locations in which~~,~~ ~~BES Cyber Assets,~~ BES Cyber Systems~~,~~ or Electronic Access Control ~~or Monitoring~~ Systems reside~~,~~ and for which access is controlled.
Removable Media	Storage media that (i) are not Cyber Assets, (ii) are capable of transferring executable code, (iii) can be used to store, copy, move, or access data, and (iv) are directly connected for 30 consecutive calendar days or less to a BES Cyber Asset, a network within an ESP, or a Protected Cyber Asset. Examples include, but are not limited to, floppy disks, compact disks, USB flash drives, external hard drives, and other flash memory cards/drives that contain nonvolatile memory.	Storage media that (i) are not Cyber Assets, (ii) are capable of transferring executable code, (iii) can be used to store, copy, move, or access data, and (iv) are directly connected for 30 consecutive calendar days or less to a BES Cyber ~~Asset~~System, ~~a network within an ESP,~~ or a Protected Cyber ~~Asset~~System. ~~Examples include, but are not limited to, floppy disks, compact disks, USB flash drives, external hard drives, and other flash memory cards/drives that contain nonvolatile memory.~~
Secure Configuration	N/A	The implemented set of controls supporting the security objectives found within the CIP Reliability Standards where the following text exists within the requirement language: "NOTE: The implemented configuration in support of this Part becomes part of the Secure Configuration of the applicable system."

The Background, VRF/VSLs, and Guidelines and Technical Basis Sections have been removed for this informal posting. The Project 2016-02 is seeking comments around the concept of the Requirement/Measure language at this time. All other sections will be modified prior to the initial posting.

A. Introduction

1. **Title:** Cyber Security — Personnel & Training

2. **Number:** CIP-004-7~~6~~

3. **Purpose:** To minimize the risk against compromise that could lead to misoperation or instability in the Bulk Electric System (BES) from individuals accessing BES Cyber Systems by requiring an appropriate level of personnel risk assessment, training, and security awareness in support of protecting BES Cyber Systems.

4. **Applicability:**

   4.1. Functional Entities: For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as "Responsible Entities." For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.

   4.1.1. Balancing Authority

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

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

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

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

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

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

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

4.1.3. Generator Operator

4.1.4. Generator Owner~~Interchange Coordinator or Interchange Authority~~

4.1.5. Reliability Coordinator

4.1.6. Transmission Operator

4.1.7. Transmission Owner

4.2. Facilities: For the ~~purpose of the~~ requirements in this standard~~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 explicitly specified ~~explicitly~~.

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

4.2.1.1. Each UFLS or UVLS System that:

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

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

4.2.1.2. Each ~~SPS or~~ RAS where the ~~SPS or~~ RAS is subject to one or more requirements in a NERC or Regional Reliability Standard.

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

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

4.2.2. Responsible Entities listed in 4.1 other than Distribution Providers: All BES Facilities.

4.2.3. Exemptions: The following are exempt from Standard CIP-004-7~~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- BES Cyber Systems' Logical Isolation Zones~~discrete Electronic Security Perimeters~~.

4.2.3.3. Cyber Assets associated with communication networks and data communication links used to extend a Logical Isolation Zone to more than one geographic location.

~~**4.2.3.2.**~~**4.2.3.4.** 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.

~~**4.2.3.3.**~~**4.2.3.5.** For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

~~**4.2.3.4.**~~**4.2.3.6.** Responsible Entities that identify that they have no BES Cyber Systems categorized as high impact or medium impact according to the CIP-002-5.1 identification and categorization processes.

5. Effective Dates: See Implementation Plan for CIP-004-7~~6~~.

B. Requirements and Measures

R1. Each Responsible Entity shall implement one or more documented processes that collectively include each of the applicable requirement parts in *CIP-004-7~~6~~ Table R1 – Security Awareness Program*.

M1. Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-004-7~~6~~ Table R1 – Security Awareness Program* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-004-7~~6~~ Table R1 – Security Awareness Program			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.1	High Impact BES Cyber Systems Medium Impact BES Cyber Systems	Security awareness that, at least once each calendar quarter, reinforces cyber security practices (which may include associated physical security practices) for the Responsible Entity's personnel who have authorized electronic or authorized unescorted physical access to BES Cyber Systems.	An example of evidence may include, but is not limited to, documentation that the quarterly reinforcement has been provided. Examples of evidence of reinforcement may include, but are not limited to, dated copies of information used to reinforce security awareness, as well as evidence of distribution, such as: • direct communications (for example, e-mails, memos, computer-based training); or • indirect communications (for example, posters, intranet, or brochures); or • management support and reinforcement (for example, presentations or meetings).

R2. Each Responsible Entity shall implement one or more cyber security training program(s) appropriate to individual roles, functions, or responsibilities that collectively includes each of the applicable requirement parts in *CIP-004-7~~6~~ Table R2 – Cyber Security Training Program*.

M2. Evidence must include the training program that includes each of the applicable requirement parts in *CIP-004-7~~6~~ Table R2 – Cyber Security Training Program* and additional evidence to demonstrate implementation of the program(s).

CIP-004-7~~6~~ Table R2 – Cyber Security Training Program			
Part	**Applicable Systems**	**Requirements**	**Measures**
2.1	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; and 2. PACS Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EAC~~M~~S; and 2. PACS	Training content on: 2.1.1. Cyber security policies; 2.1.2. Physical access controls; 2.1.3. Electronic access controls; 2.1.4. The visitor control program; 2.1.5. Handling of BES Cyber System Information and its storage; 2.1.6. Identification of a Cyber Security Incident and initial notifications in accordance with the entity's incident response plan; 2.1.7. Recovery plans for BES Cyber Systems; 2.1.8. Response to Cyber Security Incidents; and 2.1.9. Cyber security risks associated with a BES Cyber System's electronic interconnectivity and interoperability with other Cyber Assets, including Transient Cyber Assets, and with Removable Media.	Examples of evidence may include, but are not limited to, training material such as power point presentations, instructor notes, student notes, handouts, or other training materials.

CIP-004-7 Table R2 – Cyber Security Training Program			
Part	**Applicable Systems**	**Requirements**	**Measures**
2.2	High Impact BES Cyber Systems and their associated: 1. EACMS; and 2. PACS Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EACMS; and 2. PACS	Require completion of the training specified in Part 2.1 prior to granting authorized electronic access and authorized unescorted physical access to applicable Cyber Assets, except during CIP Exceptional Circumstances.	Examples of evidence may include, but are not limited to, training records and documentation of when CIP Exceptional Circumstances were invoked.
2.3	High Impact BES Cyber Systems and their associated: 1. EACMS; and 2. PACS Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EACMS; and 2. PACS	Require completion of the training specified in Part 2.1 at least once every 15 calendar months.	Examples of evidence may include, but are not limited to, dated individual training records.

R3. Each Responsible Entity shall implement one or more documented personnel risk assessment program(s) to attain and retain authorized electronic or authorized unescorted physical access to BES Cyber Systems that collectively include each of the applicable requirement parts in *CIP-004-7~~6~~ Table R3 – Personnel Risk Assessment Program*.

M3. Evidence must include the documented personnel risk assessment programs that collectively include each of the applicable requirement parts in *CIP-004-7~~6~~ Table R3 – Personnel Risk Assessment Program* and additional evidence to demonstrate implementation of the program(s).

CIP-004-7~~6~~ Table R3 – Personnel Risk Assessment Program			
Part	**Applicable Systems**	**Requirements**	**Measures**
3.1	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; ~~and~~ 2. PACS; and ~~2.~~3. PCS Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EAC~~M~~S; ~~and~~ 2. PACS; and ~~2.~~3. PCS	Process to confirm identity.	An example of evidence may include, but is not limited to, documentation of the Responsible Entity's process to confirm identity.

CIP-004-7~~6~~ Table R3 – Personnel Risk Assessment Program			
Part	**Applicable Systems**	**Requirements**	**Measures**
3.2	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; ~~and~~ 2. PACS; and ~~2.~~3. PCS Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EAC~~M~~S; ~~and~~ 2. PACS; and ~~2.~~3. PCS	Process to perform a seven year criminal history records check as part of each personnel risk assessment that includes: 3.2.1. current residence, regardless of duration; and 3.2.2. other locations where, during the seven years immediately prior to the date of the criminal history records check, the subject has resided for six consecutive months or more. If it is not possible to perform a full seven year criminal history records check, conduct as much of the seven year criminal history records check as possible and document the reason the full seven year criminal history records check could not be performed.	An example of evidence may include, but is not limited to, documentation of the Responsible Entity's process to perform a seven year criminal history records check.

CIP-004-7~~6~~ Table R3 – Personnel Risk Assessment Program			
Part	**Applicable Systems**	**Requirements**	**Measures**
3.3	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; ~~and~~ 2. PACS; and ~~2.~~3. PCS Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EAC~~M~~S; ~~and~~ 2. PACS; and ~~2.~~3. PCS	Criteria or process to evaluate criminal history records checks for authorizing access.	An example of evidence may include, but is not limited to, documentation of the Responsible Entity's process to evaluate criminal history records checks.
3.4	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; ~~and~~ 2. PACS; and ~~2.~~3. PCS Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EAC~~M~~S; ~~and~~ 2. PACS; and ~~2.~~3. PCS	Criteria or process for verifying that personnel risk assessments performed for contractors or service vendors are conducted according to Parts 3.1 through 3.3.	An example of evidence may include, but is not limited to, documentation of the Responsible Entity's criteria or process for verifying contractors or service vendors personnel risk assessments.

CIP-004-7~~6~~ Table R3 – Personnel Risk Assessment Program			
Part	**Applicable Systems**	**Requirements**	**Measures**
3.5	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; ~~and~~ 2. PACS; and ~~2.~~3. PCS Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EAC~~M~~S; ~~and~~ 2. PACS; and ~~2.~~3. PCS	Process to ensure that individuals with authorized electronic or authorized unescorted physical access have had a personnel risk assessment completed, except during CIP Exceptional Circumstances, according to Parts 3.1 to 3.4 within the last seven years.	An example of evidence may include, but is not limited to, documentation of the Responsible Entity's process for ensuring that individuals with authorized electronic or authorized unescorted physical access have had a personnel risk assessment completed within the last seven years.

R4. Each Responsible Entity shall implement one or more documented access management program(s) that collectively include each of the applicable requirement parts in *CIP-004-7~~6~~ Table R4 – Access Management Program.*

M4. Evidence must include the documented processes that collectively include each of the applicable requirement parts in *CIP-004-7~~6~~ Table R4 – Access Management Program* and additional evidence to demonstrate that the access management program was implemented as described in the Measures column of the table.

CIP-004-7~~6~~ Table R4 – Access Management Program			
Part	**Applicable Systems**	**Requirements**	**Measures**
4.1	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; ~~and~~ ~~1.~~2. EAMS; 3. PACS; 4. PAMS; and ~~2.~~5. PCS Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EAC~~M~~S; ~~and~~ ~~1.~~2. EAMS; 3. PACS; 4. PAMS; and ~~2.~~5. PCS	Process to authorize based on need, as determined by the Responsible Entity, except for CIP Exceptional Circumstances: 4.1.1. Electronic access; 4.1.2. Unescorted physical access into a Physical Security Perimeter; and 4.1.3. Access to designated storage locations (including EAMS and PAMS)~~,~~ whether physical or electronic, for BES Cyber System Information.	An example of evidence may include, but is not limited to, dated documentation of the process to authorize electronic access, unescorted physical access in a Physical Security Perimeter, and access to designated storage locations, whether physical or electronic, for BES Cyber System Information.

CIP-004-7~~6~~ Table R4 – Access Management Program			
Part	**Applicable Systems**	**Requirements**	**Measures**
4.2	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; ~~and~~ ~~1.~~2. EAMS; 3. PACS; 4. PAMS; and ~~2.~~5. PCS Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EAC~~M~~S; ~~and~~ ~~1.~~2. EAMS; 3. PACS; 4. PAMS; and ~~2.~~5. PCS	Verify at least once each calendar quarter that individuals with active electronic access or unescorted physical access have authorization records.	Examples of evidence may include, but are not limited to: • Dated documentation of the verification between the system generated list of individuals who have been authorized for access (i.e., workflow database) and a system generated list of personnel who have access (i.e., user account listing), or • Dated documentation of the verification between a list of individuals who have been authorized for access (i.e., authorization forms) and a list of individuals provisioned for access (i.e., provisioning forms or shared account listing).

CIP-004-7~~6~~ Table R4 – Access Management Program			
Part	**Applicable Systems**	**Requirements**	**Measures**
4.3	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; ~~1.~~2. EAMS; ~~and~~ 3. PACS; and ~~2.~~4. PAMS Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EAC~~M~~S; ~~1.~~2. EAMS; ~~and~~ 3. PACS; and ~~2.~~4. PAMS	For electronic access, verify at least once every 15 calendar months that all user accounts, user account groups, or user role categories, and their specific, associated privileges are correct and are those that the Responsible Entity determines are necessary.	An example of evidence may include, but is not limited to, documentation of the review that includes all of the following: 1. A dated listing of all accounts/account groups or roles within the system; 2. A summary description of privileges associated with each group or role; 3. Accounts assigned to the group or role; and 4. Dated evidence showing verification of the privileges for the group are authorized and appropriate to the work function performed by people assigned to each account.

CIP-004-7~~6~~ Table R4 – Access Management Program			
Part	**Applicable Systems**	**Requirements**	**Measures**
4.4	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; ~~1.~~2. EAMS; and 3. PACS; and ~~2.~~4. PAMS Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EAC~~M~~S; ~~1.~~2. EAMS; and 3. PACS; and ~~2.~~4. PAMS	Verify at least once every 15 calendar months that access to the designated storage locations for BES Cyber System Information, whether physical or electronic, including EAMS and PAMS are correct and are those that the Responsible Entity determines are necessary for performing assigned work functions.	An example of evidence may include, but is not limited to, the documentation of the review that includes all of the following: 1. A dated listing of authorizations for BES Cyber System information; 2. Any privileges associated with the authorizations; and 3. Dated evidence showing a verification of the authorizations and any privileges were confirmed correct and the minimum necessary for performing assigned work functions.

R5. Each Responsible Entity shall implement one or more documented access revocation program(s) that collectively include each of the applicable requirement parts in *CIP-004-7~~6~~ Table R5 – Access Revocation*.

M5. Evidence must include each of the applicable documented programs that collectively include each of the applicable requirement parts in *CIP-004-7~~6~~ Table R5 – Access Revocation* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-004-7~~6~~ Table R5 – Access Revocation			
Part	**Applicable Systems**	**Requirements**	**Measures**
5.1	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; ~~and~~ ~~1.~~2. EAMS; 3. PACS; 4. PAMS; and ~~2.~~5. PCS Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EAC~~M~~S; ~~and~~ ~~1.~~2. EAMS; 3. PACS; 4. PAMS; and ~~2.~~5. PCS	A process to initiate removal of an individual's ability for unescorted physical access and Interactive Remote Access upon a termination action, and complete the removals within 24 hours of the termination action (Removal of the ability for access may be different than deletion, disabling, revocation, or removal of all access rights).	An example of evidence may include, but is not limited to, documentation of all of the following: 1. Dated workflow or sign-off form verifying access removal associated with the termination action; and 2. Logs or other demonstration showing such persons no longer have access.

CIP-004-7~~6~~ Table R5 – Access Revocation			
Part	**Applicable Systems**	**Requirements**	**Measures**
5.2	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; ~~and~~ ~~1.~~2. EAMS; 3. PACS; 4. PAMS; and ~~2.~~5. PCS Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EACMS; ~~and~~ ~~1.~~2. EAMS; 3. PACS; 4. PAMS; and ~~2.~~5. PCS	For reassignments or transfers, revoke the individual's authorized electronic access to individual accounts and authorized unescorted physical access that the Responsible Entity determines are not necessary by the end of the next calendar day following the date that the Responsible Entity determines that the individual no longer requires retention of that access.	An example of evidence may include, but is not limited to, documentation of all of the following: 1. Dated workflow or sign-off form showing a review of logical and physical access; and 2. Logs or other demonstration showing such persons no longer have access that the Responsible Entity determines is not necessary.

CIP-004-7~~6~~ Table R5 – Access Revocation			
Part	**Applicable Systems**	**Requirements**	**Measures**
5.3	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; ~~1.~~2. EAMS; ~~and~~ 3. PACS; and ~~2.~~4. PAMS Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EAC~~M~~S; ~~1.~~2. EAMS; and 3. PACS; and ~~2.~~4. PAMS	For termination actions, revoke the individual's access to the designated storage locations for BES Cyber System Information, whether physical or electronic (unless already revoked according to Requirement R5.1), including EAMS and PAMS by the end of the next calendar day following the effective date of the termination action.	An example of evidence may include, but is not limited to, workflow or sign-off form verifying access removal to designated physical areas or cyber systems containing BES Cyber System Information associated with the terminations and dated within the next calendar day of the termination action.
5.4	High Impact BES Cyber Systems and their associated ~~:~~ EAC~~M~~S.	For termination actions, revoke the individual's non-shared user accounts (unless already revoked according to Parts 5.1 or 5.3) within 30 calendar days of the effective date of the termination action.	An example of evidence may include, but is not limited to, workflow or sign-off form showing access removal for any individual BES Cyber ~~Assets~~ Systems and software applications as determined necessary to completing the revocation of access and dated within thirty calendar days of the termination actions.

CIP-004-7~~6~~ Table R5 – Access Revocation			
Part	**Applicable Systems**	**Requirements**	**Measures**
5.5	High Impact BES Cyber Systems and their associated ~~:~~ EAC~~M~~S.	For termination actions, change passwords for shared account(s) known to the user within 30 calendar days of the termination action. For reassignments or transfers, change passwords for shared account(s) known to the user within 30 calendar days following the date that the Responsible Entity determines that the individual no longer requires retention of that access. If the Responsible Entity determines and documents that extenuating operating circumstances require a longer time period, change the password(s) within 10 calendar days following the end of the operating circumstances.	Examples of evidence may include, but are not limited to: • Workflow or sign-off form showing password reset within 30 calendar days of the termination; • Workflow or sign-off form showing password reset within 30 calendar days of the reassignments or transfers; or • Documentation of the extenuating operating circumstance and workflow or sign-off form showing password reset within 10 calendar days following the end of the operating circumstance.

C. Compliance

1. **Compliance Monitoring Process:**

   1.1. Compliance Enforcement Authority: As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

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

   The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

   - Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
   - If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
   - The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

   1.3. Compliance Monitoring and Assessment Processes:

   - Compliance Audits
   - Self-Certifications
   - Spot Checking
   - Compliance Violation Investigations
   - Self-Reporting
   - Complaints

   1.4. Additional Compliance Information:
   None.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change "Control Center" to "control center."	3/24/06
2	9/30/09	Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3	12/16/09	Updated Version Number from -2 to -3 In Requirement 1.6, deleted the sentence pertaining to removing component or system from service in order to perform testing, in response to FERC order issued September 30, 2009.	
3	12/16/09	Approved by the NERC Board of Trustees.	
3	3/31/10	Approved by FERC.	
4	1/24/11	Approved by the NERC Board of Trustees.	

Version	Date	Action	Change Tracking
5	11/26/12	Adopted by the NERC Board of Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.
5	11/22/13	FERC Order issued approving CIP-004-5.	
5.1	9/30/13	Modified two VSLs in R4	Errata
6	11/13/14	Adopted by the NERC Board of Trustees.	Addressed two FERC directives from Order No. 791 related to identify, assess, and correct language and communication networks.
6	2/12/15	Adopted by the NERC Board of Trustees.	Replaces the version adopted by the Board on 11/13/2014. Revised version addresses remaining directives from Order No. 791 related to transient devices and low impact BES Cyber Systems.
6	1/21/16	FERC order issued approving CIP-004-6. Docket No. RM15-14-000	

The Background, VRF/VSLs, and Guidelines and Technical Basis Sections have been removed for this informal posting. The Project 2016-02 is seeking comments around the concept of the Requirement/Measure language at this time. All other sections will be modified prior to the initial posting.

A. Introduction

1. **Title:** Cyber Security —-BES Cyber System Logical Isolation~~Electronic Security Perimeter(s)~~

2. **Number:** CIP-005-7~~6~~

3. **Purpose:** To protect BES Cyber Systems against compromise by allowing only known and controlled communication to and from the system and logically isolating all other communication.~~manage electronic access to BES Cyber Systems by specifying a controlled Electronic Security Perimeter in support of protecting BES Cyber Systems against compromise that could lead to misoperation or instability in the BES.~~

4. **Applicability:**

   4.1. Functional Entities: For the ~~purpose of the~~ requirements in this standard~~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 explicitly 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 Remedial Action Scheme (RAS) where the RAS is subject to one or more requirements in a NERC or Regional Reliability Standard.

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

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

4.1.3. Generator Operator

4.1.4. Generator Owner

~~**4.1.5. Interchange Coordinator or Interchange Authority**~~

~~**4.1.6.**~~**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 in this standard~~contained herein~~, the following Facilities, systems, and equipment owned by each Responsible Entity in Section 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are explicitly 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 RAS where the RAS is subject to one or more requirements in a NERC or Regional Reliability Standard.

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

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

4.2.2. Responsible Entities listed in 4.1 other than Distribution Providers:

All BES Facilities.

4.2.3. Exemptions: The following are exempt from Standard CIP-005-7~~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 BES Cyber Systems' Logical Isolation Zones~~discrete Electronic Security Perimeters~~.

~~**4.2.3.2.**~~**4.2.3.3.** Cyber Assets associated with communication networks and data communication links used to extend a Logical Isolation Zone to more than one geographic location.

~~**4.2.3.3.**~~**4.2.3.4.** 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.**~~**4.2.3.5.** For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

~~**4.2.3.5.**~~**4.2.3.6.** Responsible Entities that identify that they have no BES Cyber Systems categorized as high impact or medium impact according to the CIP-002-5 identification and categorization processes.

5. Effective Date:

See Implementation Plan for ~~Project 2016-03~~CIP-005-7.

B. Requirements and Measures

R1. Each Responsible Entity shall implement one or more documented processes to mitigate the risk posed by unauthorized communications to and from applicable systems ~~-~~that collectively include each of the applicable requirement parts in *CIP-005-7~~6~~ Table R1 –* *Logical Isolation Zones.* These processes exclude consideration of time-sensitive protection or control functions between intelligent electronic devices (e.g., communications using protocol IEC TR-61850-90-5 R-GOOSE) ~~*Electronic Security Perimeter*~~.

M1. Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-005-7~~6~~ Table R1 –* *Logical Isolation Zones* ~~*Electronic Security Perimeter*~~ and additional Evidence to demonstrate implementation as described in the Measures column of the table.

CIP-005-6 Table R1 – ~~Electronic Security Perimeter~~Logical Isolation Zones			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.~~1~~3	~~Electronic Access Points for~~ High Impact BES Cyber Systems ~~Electronic Access Points for~~ Medium Impact BES Cyber Systems	Have one or more methods to logically isolate applicable systems, either individually or as a group, by only allowing: 1.1.1. ~~Require~~Communication that has documented inbound and outbound access permissions, including the reason for granting access; and~~, and deny all other access by default.~~ 1.2.1. Serial port connectivity such as RS-232 and RS-485. NOTE: The implemented configuration in support of this Part becomes part of the Secure Configuration of the applicable system.	Evidence may include, but is not limited to, configuration of systems that enforce logical isolation such as network infrastructure configuration (ACL, VLAN, VXLAN, MPLS), compute configuration (e.g., Hypervisor, containers), storage system configuration (e.g., SAN, NAS, DAS). ~~An example of evidence may include, but is not limited to, a list of rules (firewall, access control lists, etc.) that demonstrate that only permitted access is allowed and that each access rule has a documented reason.~~

CIP-005-6 Table R1 – ~~Electronic Security Perimeter~~Logical Isolation Zones			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.2	High Impact BES Cyber Systems and their associated PCS Medium Impact BES Cyber Systems and their associated PCS	Protect the data traversing communication networks used to provide connectivity between components of a Logically Isolated Zone that spans multiple geographic locations to preserve confidentiality and integrity.	Evidence may include, but is not limited to, architecture documents detailing the methods used to mitigate the risk of unauthorized disclosure. Examples include physical protection and the points where encryption initiates and terminates.
1.34	High Impact BES Cyber Systems with Dial-up Connectivity and their associated PCS ~~A~~ Medium Impact BES Cyber Systems with Dial-up Connectivity and their associated PCS~~A~~	~~Where technically feasible,~~ Pperform authentication when establishing Dial-up Connectivity with applicable Cyber Assets~~.~~ per system capability.	An example of evidence may include, but is not limited to, a documented process that describes how the Responsible Entity is providing authenticated access through each dial-up connection.
1.45	~~Electronic Access Points for~~ High Impact BES Cyber Systems and their associated PCS ~~Electronic Access Points for~~ Medium Impact BES Cyber Systems at Control Centers and their associated PCS	Have one or more methods for detecting known or suspected malicious inbound and outbound communications to and from applicable systems either individually or as grouped in Part 1.1, excluding serial port connectivity such as RS-232 and RS-485.	~~An example of e~~Evidence may include, but is not limited to, documentation that malicious communications detection methods (e.g. intrusion detection system, application layer firewall, privileged introspection, etc.) are implemented.

R2. Each Responsible Entity shall implement one or more documented processes to mitigate the risk posed by exploitation of Interactive Remote Access that collectively include the applicable requirement parts, ~~where technically feasible,~~per system capability, in *CIP-005-6 Table R2 –Remote Access Management*.

M2. Evidence must include the documented processes that collectively address each of the applicable requirement parts in *CIP-005-6 Table R2 – Remote Access Management* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-005-76 Table R2 ~~–Remote Access Management~~ Remote Access Management			
Part	**Applicable Systems**	**Requirements**	**Measures**
2.1	High Impact BES Cyber Systems and their associated ~~:~~ PCS ~~A~~ Medium Impact BES Cyber Systems ~~with External Routable Connectivity~~ and their associated ~~:~~ PCS~~A~~	Have one or more methods to ~~For all Interactive~~ ensure that Interactive Remote Access~~,~~ to applicable systems is through an Intermediate System that is isolated from the BES Cyber System and restricts Interactive Remote Access to only authorized users. ~~utilize an Intermediate System such that the Cyber Asset initiating Interactive Remote Access does not directly access an applicable Cyber Asset.~~	E~~xamples of e~~vidence may include, but ~~are~~ is not limited to, network diagrams or architecture documents.
2.2	High Impact BES Cyber Systems and their associated ~~:~~ PCS ~~A~~ Medium Impact BES Cyber Systems ~~with External Routable Connectivity~~ and their associated~~:~~	Have one or more methods to mitigate the risks posed by unauthorized modification and unauthorized disclosure of data during ~~For~~ all Interactive Remote Access sessions~~,~~ that terminate at an Intermediate System ~~utilize~~	~~An example of e~~Evidence may include, but is not limited to, architecture documents detailing the methods used to mitigate the risk of unauthor~~e~~ized disclosure. Examples include illustrating where encryption initiates and terminates.

CIP-005-76 Table R2 — Remote Access Management Remote Access Management			
Part	**Applicable Systems**	**Requirements**	**Measures**
	• PCSA	encryption that terminates at an Intermediate System.	
2.3	High Impact BES Cyber Systems and their associate d: PCS A Medium Impact BES Cyber Systems with External Routable Connectivity and their associated PCSA	Have one or more methods to Rrequire multi-factor authentication for all Interactive Remote Access sessions.	An example of eEvidence may include, but is not limited to, architecture documents detailing the authentication factors used. Examples of authenticators may include, but are not limited to, Something the individual knows such as passwords or PINs. This does not include User ID; Something the individual has such as tokens, digital certificates, or smart cards; or Something the individual is such as fingerprints, iris scans, or other biometric characteristics.

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CIP-005-76 Table R2 — Remote Access Management Remote Access Management			
Part	**Applicable Systems**	**Requirements**	**Measures**
2.4	High Impact BES Cyber Systems and their associatedassociated : PCS A Medium Impact BES Cyber Systems with External Routable Connectivity and their associated : PCSA	Have one or more methods for determining active vendor remote access sessions (including Interactive Remote Access and system-to-system remote access).	Examples of eEvidence may include, but isare not limited to documented methods such as: • Methods for accessing logged information or monitoring information to determine active vendor remote access sessions; • Methods for monitoring activity (e.g. connection tables or rule hit counters in a firewall, or user activity monitoring) or open ports (e.g. netstat or related commands to display currently active ports) to determine active system to system remote access sessions; or • Methods that control vendor initiation of remote access such as requiring vendors to call and request calling and requesting a second factor toin order to initiate remote access.

CIP-005-76 Table R2 — Remote Access Management Remote Access Management			
Part	**Applicable Systems**	**Requirements**	**Measures**
2.5	High Impact BES Cyber Systems and their associated • PCS A Medium Impact BES Cyber Systems with External Routable Connectivity and their associated • PCSA	Have one or more method(s) to disable active vendor remote access (including Interactive Remote Access and system-to-system remote access).	Examples of eEvidence may include, but are is not limited to, documentedion of the methods(s) used to disable active vendor remote access (including Interactive Remote Access and system-to-system remote access), such as: • Methods to disable vendor remote access at the applicable Electronic Access Point for system-to-system remote access; or • Methods to disable vendor Interactive Remote Access at the applicable Intermediate System.

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R3. Each Responsible Entity shall implement one or more documented processes to mitigate the risk posed by unrestricted access for communication between the management plane[1] and the data plane[2] that collectively include the applicable requirement parts, in *CIP-005-6 Table R3* – Isolation of Management Plane and Data Plane.

[1] Management plane of a system is that element that configures, monitors, and provides management, monitoring and configuration services to, all layers of the network stack and other parts of the system.

[2] Data plane (sometimes known as the user plane, forwarding plane, carrier plane or bearer plane) is the part of a network that carries user traffic.

M3. Evidence must include the documented processes that collectively address each of the applicable requirement parts in *CIP-005-6 Table R3* – Isolation of Management Plane and Data Plane and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-005-6 Table R3 – Isolation of Management Plane and Data Plane			
Part	**Applicable Systems**	**Requirements**	**Measures**
3.1	High Impact BES Cyber Systems and their associated: 1. EACS 2. PCS Medium Impact BES Cyber Systems and their associated PCS: 1. EACS 2. PCS	Have one or more methods per system capability to: 1. Restrict access to the management plane; and 2. Logically isolate the management plane from the data plane.	An example of evidence may include but is not limited to documentation that includes the following: Configuration of systems that enforce authentication and logical isolation such as network infrastructure configuration (ACL, VLAN, VXLAN, MPLS), compute configuration (e.g. Hypervisor, containers), storage system configuration (e.g. SAN, NAS, DAS).

C. Compliance

1. **Compliance Monitoring Process**

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

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

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

   - Each applicable entity shall retain evidence of each requirement in this standard for three calendar 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 CEA shall keep the last audit records and all requested and submitted subsequent audit records.

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

D. Regional Variances

None.

E. 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.	
3	3/31/10	Approved by FERC.	
4	12/30/10	Modified to add specific criteria for Critical Asset identification.	Update
4	1/24/11	Approved by the NERC Board of Trustees.	Update
5	11/26/12	Adopted by the NERC Board of Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.
5	11/22/13	FERC Order issued approving CIP-005-5.	
6	07/20/17	Modified to address certain directives in FERC Order No. 829.	Revised
6	08/10/17	Adopted by the NERC Board of Trustees.	

The Background, VRF/VSLs, and Guidelines and Technical Basis Sections have been removed for this informal posting. The Project 2016-02 is seeking comments around the concept of the Requirement/Measure language at this time. All other sections will be modified prior to the initial posting.

A. Introduction

1. Title: Cyber Security — Physical Security of BES Cyber Systems

2. Number: CIP-006-7~~6~~

3. Purpose: To manage physical access to Bulk Electric System (BES) Cyber Systems by specifying a physical security plan in support of protecting BES Cyber Systems against compromise that could lead to misoperation or instability in the BES.

4. Applicability:

4.1. Functional Entities: For the ~~purpose of the~~ requirements in this standard~~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 explicitly specified ~~explicitly~~.

4.1.1 Balancing Authority

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

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

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

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

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

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

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

4.1.3 Generator Operator

4.1.4 Generator Owner

~~**4.1.5 Interchange Coordinator or Interchange Authority**~~

~~4.1.6~~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 in this standard~~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 explicitly specified ~~explicitly~~.

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

4.2.1.1 Each UFLS or UVLS System that:

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

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

4.2.1.2 Each ~~SPS or~~ RAS where the ~~SPS or~~ RAS is subject to one or more requirements in a NERC or Regional Reliability Standard.

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

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

4.2.2 Responsible Entities listed in 4.1 other than Distribution Providers:

All BES Facilities.

4.2.3 Exemptions: The following are exempt from Standard ~~CIP-006-6~~CIP-006-7:

4.2.3.1 Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

4.2.3.2 Cyber Assets associated with communication networks and data communication links between~~-~~ BES Cyber Systems' Logical Isolation Zones. ~~discrete Electronic Security Perimeters~~.

4.2.3.3 Cyber Assets associated with communication networks and data communication links used to extend a Logical Isolation Zone to more than one geographic location.

~~**4.2.3.2**~~**4.2.3.4** 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.

~~**4.2.3.3**~~**4.2.3.5** For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

~~**4.2.3.4**~~**4.2.3.6** Responsible Entities that identify that they have no BES Cyber Systems categorized as high impact or medium impact according to the CIP-002-5.1 identification and categorization processes.

5. Effective Dates:

See Implementation Plan for CIP-006-7~~6~~.

B. Requirements and Measures

R1. Each Responsible Entity shall implement~~, except during CIP Exceptional Circumstances,~~ one or more documented physical security plan(s) that collectively include all of the applicable requirement parts in *CIP-006-7~~6~~ Table R1 – Physical Security Plan*.

M1. Evidence must include each of the documented physical security plans that collectively include all of the applicable requirement parts in *CIP-006-7~~6~~ Table R1 – Physical Security Plan* and additional evidence to demonstrate implementation of the plan or plans as described in the Measures column of the table.

CIP-006-7~~6~~ Table R1 – Physical Security Plan			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.1	Medium Impact BES Cyber Systems without External Routable Connectivity Physical Access Control Systems (PACS) associated with: • High Impact BES Cyber Systems, or • Medium Impact BES Cyber Systems with External Routable Connectivity • ~~Programmable electronic device without External Routable Connectivity (ERC)~~	Define operational or procedural controls to restrict physical access.	An example of evidence may include, but is not limited to, documentation that operational or procedural controls exist.

CIP-006-7~~6~~ Table R1 – Physical Security Plan			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.2	Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EAC~~M~~S; and 2. PCS~~A~~	Use~~tilize~~ at least one physical access control to allow unescorted physical access into each applicable Physical Security Perimeter to only those individuals who have authorized unescorted physical access.	An example of evidence may include, but is not limited to, language in the physical security plan that describes each Physical Security Perimeter and how unescorted physical access is controlled by one or more different methods and proof that unescorted physical access is restricted to only authorized individuals, such as a list of authorized individuals accompanied by access logs.

CIP-006-7~~6~~ Table R1 – Physical Security Plan			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.3	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; and 2. PCS~~A~~	Where technically feasible, use~~tilize~~ two or more different physical access controls (this does not require two completely independent physical access control systems) to collectively allow unescorted physical access into Physical Security Perimeters to only those individuals who have authorized unescorted physical access.	An example of evidence may include, but is not limited to, language in the physical security plan that describes the Physical Security Perimeters and how unescorted physical access is controlled by two or more different methods and proof that unescorted physical access is restricted to only authorized individuals, such as a list of authorized individuals accompanied by access logs.

CIP-006-7~~6~~ Table R1– Physical Security Plan			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.4	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; and 2. PC~~S~~A Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EAC~~M~~S; and 2. PC~~S~~A	Monitor for unauthorized access through a physical access point into a Physical Security Perimeter.	An example of evidence may include, but is not limited to, documentation of controls that monitor for unauthorized access through a physical access point into a Physical Security Perimeter.

CIP-006-7~~6~~ Table R1– Physical Security Plan			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.5	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; and 2. PC~~S~~A Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EAC~~M~~S; and 2. PC~~S~~A	Issue an alarm or alert in response to detected unauthorized access through a physical access point into a Physical Security Perimeter to the personnel identified in the BES Cyber Security Incident response plan within 15 minutes of detection.	An example of evidence may include, but is not limited to, language in the physical security plan that describes the issuance of an alarm or alert in response to unauthorized access through a physical access control into a Physical Security Perimeter and additional evidence that the alarm or alert was issued and communicated as identified in the BES Cyber Security Incident Response Plan, such as manual or electronic alarm or alert logs, cell phone or pager logs, or other evidence that documents that the alarm or alert was generated and communicated.
1.6	Physical Access Control Systems (PACS) associated with: • High Impact BES Cyber Systems, or • Medium Impact BES Cyber Systems with External Routable Connectivity	Monitor each Physical Access Control System for unauthorized physical access to a Physical Access Control System.	An example of evidence may include, but is not limited to, documentation of controls that monitor for unauthorized physical access to a PACS.

CIP-006-7 Table R1– Physical Security Plan			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.7	Physical Access Control Systems (PACS) associated with: • High Impact BES Cyber Systems, or • Medium Impact BES Cyber Systems with External Routable Connectivity	Issue an alarm or alert in response to detected unauthorized physical access to a Physical Access Control System to the personnel identified in the BES Cyber Security Incident response plan within 15 minutes of the detection.	An example of evidence may include, but is not limited to, language in the physical security plan that describes the issuance of an alarm or alert in response to unauthorized physical access to Physical Access Control Systems and additional evidence that the alarm or alerts was issued and communicated as identified in the BES Cyber Security Incident Response Plan, such as alarm or alert logs, cell phone or pager logs, or other evidence that the alarm or alert was generated and communicated.

CIP-006-7 Table R1 – Physical Security Plan			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.8	High Impact BES Cyber Systems and their associated: 1. EACMS; and 2. PCSA Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EACMS; and 2. PCSA	Log (through automated means or by personnel who control entry) entry of each individual with authorized unescorted physical access into each Physical Security Perimeter, with information to identify the individual and date and time of entry, except during CIP Exceptional Circumstances.	An example of evidence may include, but is not limited to, language in the physical security plan that describes logging and recording of physical entry into each Physical Security Perimeter and additional evidence to demonstrate that this logging has been implemented, such as logs of physical access into Physical Security Perimeters that show the individual and the date and time of entry into Physical Security Perimeter.

CIP-006-7 Table R1 – Physical Security Plan			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.9	High Impact BES Cyber Systems and their associated: 1. EACMS; and 2. PCSA Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EACMS; and 2. PCSA	Retain physical access logs of entry of individuals with authorized unescorted physical access into each Physical Security Perimeter for at least ninety calendar days, except during CIP Exceptional Circumstances.	An example of evidence may include, but is not limited to, dated documentation such as logs of physical access into Physical Security Perimeters that show the date and time of entry into Physical Security Perimeter.

~~CIP-006-6~~CIP-006-7 Table R1 – Physical Security Plan			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.10	High Impact BES Cyber Systems and their associated PC~~S~~A Medium Impact BES Cyber Systems at Control Centers and their associated ~~:~~ PC~~S~~A	Restrict physical access to cabling and other nonprogrammable communication components used for ~~for connection between~~ applicable ~~Cyber Assets~~systems ~~within~~ in the same ~~isolated BES Cyber System~~~~Electronic Security~~Logical Isolation Zone ~~Perimeter~~ -in those instances when such cabling and components are located outside of a Physical Security Perimeter. Where physical access restrictions to such cabling and components are not implemented, the Responsible Entity shall document and implement one or more of the following: • encryption of data that transits such cabling and components; or • monitoring the status of the communication link composed of such cabling and components and issuing an alarm or alert in response to detected communication failures to the personnel identified in the BES Cyber Security Incident response plan within 15 minutes of detection; or • an equally effective logical protection.	An example of evidence may include, but is not limited to, records of the Responsible Entity's implementation of the physical access restrictions (e.g., cabling and components secured through conduit or secured cable trays) encryption, monitoring, or equally effective logical protections.

R2. Each Responsible Entity shall implement, except during CIP Exceptional Circumstances, ~~-~~one or more documented visitor control program(s) that include each of the applicable requirement parts in *CIP-006-~~7~~6 Table R2 – Visitor Control Program.*

M2. Evidence must include one or more documented visitor control programs that collectively include each of the applicable requirement parts in *CIP-006-~~7~~6 Table R2 – Visitor Control Program* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-006-~~7~~6 Table R2 – Visitor Control Program			
Part	**Applicable Systems**	**Requirements**	**Measures**
2.1	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; and 2. PC~~S~~A Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EAC~~M~~S; and 2. PC~~S~~A	Require continuous escorted access of visitors (individuals who are provided access but are not authorized for unescorted physical access) within each Physical Security Perimeter~~,~~ ~~except during CIP Exceptional Circumstances~~.	An example of evidence may include, but is not limited to, language in a visitor control program that requires continuous escorted access of visitors within Physical Security Perimeters and additional evidence to demonstrate that the escorted access process was implemented, such as visitor logs.

CIP-006-7~~6~~ Table R2 – Visitor Control Program			
Part	**Applicable Systems**	**Requirements**	**Measures**
2.2	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; and 2. PC~~S~~A Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EAC~~M~~S; and 2. PC~~S~~A	Require manual or automated logging of visitor entry into and exit from the Physical Security Perimeter that includes date and time of the initial entry and last exit, the visitor's name, and the name of an individual point of contact responsible for the visitor~~, except during CIP Exceptional Circumstances~~.	An example of evidence may include, but is not limited to, language in a visitor control program that requires continuous escorted access of visitors within Physical Security Perimeters and additional evidence to demonstrate that the escorted access process was implemented, such as dated visitor logs that include the required information.
2.3	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; and 2. PC~~S~~A Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EAC~~M~~S; and 2. PC~~S~~A	Retain visitor logs for at least ninety calendar days.	An example of evidence may include, but is not limited to, documentation showing logs have been retained for at least ninety calendar days.

R3. Each Responsible Entity shall implement one or more documented Physical Access Control System maintenance and testing program(s) that collectively include each of the applicable requirement parts in *CIP-006-7~~6~~ Table R3 – Maintenance and Testing Program*.

M3. Evidence must include each of the documented Physical Access Control System maintenance and testing programs that collectively include each of the applicable requirement parts in *CIP-006-7~~6~~ Table R3 – Maintenance and Testing Program* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-006-7~~6~~ Table R3 – Physical Access Control System Maintenance and Testing Program			
Part	**Applicable Systems**	**Requirement**	**Measures**
3.1	Physical Access Control Systems (PACS) associated with: • High Impact BES Cyber Systems, or • Medium Impact BES Cyber Systems with External Routable Connectivity Locally mounted hardware or devices at the Physical Security Perimeter associated with: • High Impact BES Cyber Systems, or • Medium Impact BES Cyber Systems with External Routable Connectivity	Maintenance and testing of each Physical Access Control System and locally mounted hardware or devices at the Physical Security Perimeter at least once every 24 calendar months to ensure they function properly.	An example of evidence may include, but is not limited to, a maintenance and testing program that provides for testing each Physical Access Control System and locally mounted hardware or devices associated with each applicable Physical Security Perimeter at least once every 24 calendar months, Also, ~~and~~ additional evidence such as dated maintenance records or other documentation ~~to demonstrate that this testing was done, such as dated maintenance records, or other documentation~~ to demonstrate that ~~showing~~ testing and maintenance has been performed on each applicable device or system at least once every 24 calendar months.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention:

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

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Investigations

Self-Reporting

Complaints

1.4. Additional Compliance Information:

None

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change "Control Center" to "control center."	3/24/06
2	9/30/09	Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3	12/16/09	Updated Version Number from -2 to -3 In Requirement 1.6, deleted the sentence pertaining to removing component or system from service in order to perform testing, in response to FERC order issued September 30, 2009.	
3	12/16/09	Approved by the NERC Board of Trustees.	
3	3/31/10	Approved by FERC.	
4	1/24/11	Approved by the NERC Board of	

Version	Date	Action	Change Tracking
		Trustees.	
5	11/26/12	Adopted by the NERC Board of Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.
5	11/22/13	FERC Order issued approving CIP-006-5.	
6	11/13/14	Adopted by the NERC Board of Trustees.	Addressed FERC directives from Order No. 791.
6	1/21/16	FERC order issued approving CIP-006-6. Docket No. RM15-14-000	

The Background, VRF/VSLs, and Guidelines and Technical Basis Sections have been removed for this informal posting. The Project 2016-02 is seeking comments around the concept of the Requirement/Measure language at this time. All other sections will be modified prior to the initial posting.

A. Introduction

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

2. **Number:** CIP-007-7~~6~~

3. **Purpose:** To manage system security by specifying select technical, operational, and procedural requirements in support of protecting BES Cyber Systems against compromise that could lead to misoperation or instability in the Bulk Electric System (BES).

4. **Applicability:**

   4.1. Functional Entities: For the ~~purpose of the~~ requirements in this standard~~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 explicitly specified~~. explicitly.~~

   4.1.1. Balancing Authority

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

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

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

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

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

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

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

4.1.3. Generator Operator

4.1.4. Generator Owner~~Interchange Coordinator or Interchange Authority~~

4.1.5. Reliability Coordinator

4.1.6. Transmission Operator

4.1.7. Transmission Owner

4.2. Facilities: For the ~~purpose of the~~ requirements in this standard~~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 explicitly specified~~. explicitly.~~

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

4.2.1.1. Each UFLS or UVLS System that:

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

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

4.2.1.2. Each ~~SPS or~~ RAS where the ~~SPS or~~ RAS is subject to one or more requirements in a NERC or Regional Reliability Standard.

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

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

4.2.2. Responsible Entities listed in 4.1 other than Distribution Providers: All BES Facilities.

4.2.3. Exemptions: The following are exempt from Standard CIP-007-7~~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 BES Cyber Systems' Logical Isolation Zones (LIZ).~~discrete Electronic Security Perimeters.~~

4.2.3.3. Cyber Assets associated with communication networks and data communication links used to extend a Logical Isolation Zone to more than one geographic location.

~~**4.2.3.3.**~~**4.2.3.4.** 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.**~~**4.2.3.5.** For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

~~**4.2.3.5.**~~**4.2.3.6.** Responsible Entities that identify that they have no BES Cyber Systems categorized as high impact or medium impact according to the CIP-002-5.1 identification and categorization processes.

5. Effective Dates: See Implementation Plan for CIP-007-7~~6~~.

B. Requirements and Measures

R1. Each Responsible Entity shall implement one or more documented process(es) to mitigate the risk posed by uncontrolled logical and physical connectivity that collectively include each of the applicable requirement parts in *CIP-007-7~~6~~ Table R1 – ~~Ports and Services~~Connectivity*.

M1. Evidence must include the documented processes that collectively include each of the applicable requirement parts in *CIP-007-7~~6~~ Table R1 – ~~Ports and Services~~Connectivity* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-007-76 Table R1– Ports and ServicesConnectivity			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.1	High Impact BES Cyber Systems and their associated: 1. EACMS; 2. PACS; and 3. PCSA Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EACMS; 2. PACS; and 3. PCSA	Where technically feasible, enable only logical network accessible ports that have been determined to be needed by the Responsible Entity, including port ranges or services where needed to handle dynamic ports. If a device has no provision for disabling or restricting logical ports on the device then those ports that are open are deemed needed. Use one or a combination of the following methods (per system capability) excluding serial port connectivity such as RS-232 and RS-485: • Configure each system to provide only essential logical connectivity; • Detect and alert on malicious communication within systems; or • Baseline system logical connectivity, and alert on deviation from baseline; or • Other method(s) to mitigate the risk posed by uncontrolled logical connectivity. NOTE: The implemented configuration in support of this Part becomes part of the Secure Configuration of the applicable system.	Examples of evidence may include, but are not limited to: • Documentation of the need for all enabled ports on all enabled logical ports. applicable Cyber Assets and Electronic Access Points, individually or by group. • Listings of logical the listening ports on the Cyber Assets applicable systems, individually or by group, from either the device configuration files, command output (such as netstat), or network scans of open ports; or • Configuration files of host-based firewalls or other device level mechanisms that only allow needed ports and deny all others. • Documentation that malicious communications detection methods (e.g. intrusion detection system, application layer firewall, privileged introspection, etc.) are implemented within systems. • Any necessary combination of configuration files of system connectivity, storage connectivity, or network connectivity.

CIP-007-~~6~~7 Table R1– ~~Ports and Services~~Connectivity			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.2	High Impact BES Cyber Systems and their associated: 1. PC~~S~~SA; and 2. Nonprogrammable communication components located inside both a PSP and a~~n ESP~~LIZ. Medium Impact BES Cyber Systems at Control Centers and their associated: 1. PC~~S~~SA; and 2. Nonprogrammable communication components located inside both a PSP and a~~n ESP~~LIZ.	Protect against the use of unnecessary physical input/output ports used for network connectivity, console commands, or Removable Media.	An example of evidence may include, but is not limited to, documentation showing types of protection of physical input/output ports, either logically through system configuration or physically using a port lock or signage.

R2. Each Responsible Entity shall implement one or more documented process(es) to mitigate the risk posed by unmanaged software that collectively include each of the applicable requirement parts in *CIP-007-7~~6~~ Table R2 – ~~Security Patch~~ Software Management*.

M2. Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-007-~~6~~7 Table R2 – ~~Security Patch~~Software Management* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-007-7 Table R2 – ~~Security Patch~~Software Management			
Part	Applicable Systems	Requirements	Measures

2.1	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PCS~~A~~ Medium Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PCS~~A~~	~~A patch management process for tracking, evaluating, and installing cyber security patches for applicable Cyber Assets. The tracking portion shall include the identification of a source or sources that the Responsible Entity tracks for the release of cyber security patches for applicable Cyber Assets that are updateable and for which a patching source exists.~~ Use one or a combination of the following methods (per system capability) to allow only essential software execution, as determined by the Responsible Entity: • Configure each system with intentionally installed essential software and executable scripts; • Baseline currently installed software and executable scripts and alert on any newly installed software or executable scripts; • Implement application whitelisting; ~~or~~ • Use read-only bootable media; or • Other methods to mitigate the risk posed by unmanaged software. NOTE: The implemented configuration in support of this Part becomes part of the Secure Configuration of the applicable system.	An example of evidence may include, but is not limited to:~~, documentation of a patch management process and documentation or lists of sources that are monitored, whether on an individual BES Cyber System or Cyber Asset basis.~~ • Documentation of essential software and executable scripts; • Application whitelisting rule sets; • Documentation of read-only bootable media configuration; or • Documentation of other methods.

R3. Each Responsible Entity shall implement one or more documented process(es) to mitigate the risk posed by malicious code that collectively include each of the applicable requirement parts in *CIP-007-7~~6~~ Table R3 – Malicious Code Prevention*.

M3. Evidence must include each of the documented processes that collectively include each of the applicable requirement parts in *CIP-007-7~~6~~ Table R3 – Malicious Code Prevention* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-007-7~~6~~ Table R3 – Malicious Code Prevention			
Part	**Applicable Systems**	**Requirements**	**Measures**
3.1	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PCS~~A~~ Medium Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PCS~~A~~	Deploy method(s) to deter, detect, or prevent malicious code. NOTE: The implemented configuration in support of this Part becomes part of the Secure Configuration of the applicable system.	An example of evidence may include, but is not limited to, records of the Responsible Entity's performance of these processes (e.g., through traditional antivirus, system hardening, policies, etc.).

CIP-007-7~~6~~ Table R3 – Malicious Code Prevention			
Part	**Applicable Systems**	**Requirements**	**Measures**
3.2	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PC~~S~~A Medium Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PC~~S~~A	Mitigate the threat of detected malicious code. NOTE: The implemented configuration in support of this Part becomes part of the Secure Configuration of the applicable system.	Examples of evidence may include, but are not limited to: • Records of response processes for malicious code detection • Records of the performance of these processes when malicious code is detected.
3.3	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PC~~S~~A Medium Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PC~~S~~A	For those methods identified in Part 3.1 that use signatures or patterns, have a process for the update of the signatures or patterns. The process must address testing and installing the signatures or patterns.	An example of evidence may include, but is not limited to, documentation showing the process used for the update of signatures or patterns.

R4. Each Responsible Entity shall implement, except during CIP Exceptional Circumstances, one or more documented process(es) to monitor security events to mitigate the risk posed by detectable security incidents that collectively include each of the applicable requirement parts in *CIP-007-6 Table R4 – Security Event Monitoring*.

M4. Evidence must include each of the documented processes that collectively include each of the applicable requirement parts in *CIP-007-7~~6~~ Table R4 – Security Event Monitoring* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-007-6 Table R4 – Security Event Monitoring			
Part	**Applicable Systems**	**Requirements**	**Measures**
4.1	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PCS~~A~~ Medium Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PCS~~A~~	Log events ~~at the BES Cyber System level~~ (per ~~BES Cyber S~~system capability~~) or at the Cyber Asset level (per Cyber Asset capability~~) for identification ~~of,~~ and ~~after the fact~~ subsequent investigations of~~,~~ Cyber Security Incidents that include~~s, as a minimum,~~ each of the following types of events: 4.1.1. Detected successful login attempts; 4.1.2. Detected failed access attempts and failed login attempts; 4.1.3. Detected malicious code. NOTE: The implemented configuration in support of this Part becomes part of the Secure Configuration of the applicable system.	Examples of evidence may include, but are not limited to, a paper or system generated listing of event types that the ~~for which the~~ BES Cyber System ~~is capable of~~can detect~~ing~~ and, for generated events, is configured to log. This listing must include the required types of events.

CIP-007-6 Table R4 – Security Event Monitoring			
Part	**Applicable Systems**	**Requirements**	**Measures**
4.2	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PC~~S~~SA Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PC~~S~~SA	Generate alerts for security events that the Responsible Entity determines need ~~necessitates~~ an alert, that include~~s~~, as a minimum, each of the following types of events (per ~~Cyber Asset or BES Cyber S~~system capability): 4.2.1. Detected malicious code from Part 4.1; and 4.2.2. Detected failure of Part 4.1 event logging. NOTE: The implemented configuration in support of this Part becomes part of the Secure Configuration of the applicable system.	Examples of evidence may include, but are not limited to, paper or system-generated list~~sing~~ of security events that the Responsible Entity determined nee~~d~~d~~cessitate~~ alerts, including paper or system generated lists showing how alerts are configured.

CIP-007-6 Table R4 – Security Event Monitoring			
Part	**Applicable Systems**	**Requirements**	**Measures**
4.3	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PC~~S~~SA Medium Impact BES Cyber Systems at Control Centers and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PC~~S~~SA	~~Per system capability~~ ~~Where technically feasible, r~~Retain applicable event logs identified in Part 4.1 per system capability for at least the last 90 consecutive calendar days. ~~except under CIP Exceptional Circumstances.~~	Examples of evidence may include, but are not limited to, documentation of the event log retention process and paper or system generated reports showing log retention configuration set at 90 days or greater.
4.4	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; and 2. PC~~S~~SA	Review a summarization or sampling of logged events as determined by the Responsible Entity at intervals no greater than 15 calendar days to identify undetected Cyber Security Incidents.	Examples of evidence may include, but are not limited to, documentation describing the review, ~~any~~ findings from the review (if any), and dated documentation showing the review occurred.

R5. Each Responsible Entity shall implement one or more documented process(es) to mitigate the risk posed by unauthorized electronic access that collectively include each of the applicable requirement parts in *CIP-007-7~~6~~ Table R5 – System Access Controls*.

M5. Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-007-~~6~~7 Table 5 – System Access Controls* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-007-7~~6~~ Table R5 – System Access Controls			
Part	**Applicable Systems**	**Requirements**	**Measures**
5.1	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PCS~~A~~ Medium Impact BES Cyber Systems at Control Centers and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PCS~~A~~ Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PCS~~A~~	Have a method(s) to enforce authentication of interactive user access, ~~where technically feasible.~~ per system capability. NOTE: The implemented configuration in support of this Part becomes part of the Secure Configuration of the applicable system.	An example of evidence may include, but is not limited to, documentation describing how access is authenticated.

CIP-007-7~~6~~ Table R5 – System Access Control			
Part	**Applicable Systems**	**Requirements**	**Measures**
5.2	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PCS~~A~~ Medium Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PCS~~A~~	Identify and inventory all known enabled default or other generic account types, either by system, by groups of systems, by location~~,~~ or by system type(s). NOTE: The implemented configuration in support of this Part becomes part of the Secure Configuration of the applicable system.	An example of evidence may include, but is not limited to, a listing of accounts by account types showing the enabled or generic account types in use for the BES Cyber System.
5.3	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PCS~~A~~ Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PCS~~A~~	Identify individuals who have authorized access to shared accounts.	An example of evidence may include, but is not limited to, listing of shared accounts and the individuals who have authorized access to each shared account.

CIP-007-6 Table R5 – System Access Control			
Part	**Applicable Systems**	**Requirements**	**Measures**
5.4	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PC~~S~~A Medium Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PC~~S~~A	Change known default passwords, per ~~Cyber Asset~~system capability	Examples of evidence may include, but are not limited to: • Records of a procedure that passwords are changed when new devices are put in production; or • Documentation in system manuals or other vendor documents showing default vendor passwords were generated pseudo-randomly and are thereby unique to the device.
5.5	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PC~~S~~A Medium Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PC~~S~~A	For password-only authentication for interactive user access, either technically or procedurally enforce the following password parameters: 5.5.1. Password length that is, at least, the lesser of eight characters or the maximum length supported by the ~~Cyber Asset~~system; and 5.5.2. ~~5.5.2~~ Minimum password complexity that is the lesser of three or more different types of characters (e.g., uppercase alphabetic, lowercase alphabetic, numeric, non-alphanumeric) or the maximum complexity supported by the ~~Cyber Asset~~system.	Examples of evidence may include, but are not limited to: • System-generated reports or screen-shots of the system-enforced password parameters, including length and complexity; or • Attestations that include a reference to the documented procedures that were followed.

		NOTE: The implemented configuration in support of this Part becomes part of the Secure Configuration of the applicable system.	

CIP-007-76 Table R5 – System Access Control			
Part	**Applicable Systems**	**Requirements**	**Measures**
5.6	High Impact BES Cyber Systems and their associated: 1. EACMS; 2. PACS; and 3. PCSA Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EACMS; 2. PACS; and 3. PCSA	Where technically feasiblePer system capability, for password-only authentication for interactive user access, either technically or procedurally enforce password changes or an obligation to change the password at least once every 15 calendar months. NOTE: The implemented configuration in support of this Part becomes part of the Secure Configuration of the applicable system.	Examples of evidence may include, but are not limited to: • System-generated reports or screen-shots of the system-enforced periodicity of changing passwords; or • Attestations that include a reference to the documented procedures that were followed.
5.7	High Impact BES Cyber Systems and their associated: 1. EACMS; 2. PACS; and 3. PCSA Medium Impact BES Cyber Systems at Control Centers and their associated: 1. EACMS; 2. PACS; and 3. PCSA	Where technically feasiblePer system capability, either: • Limit the number of unsuccessful authentication attempts; or • Generate alerts after a threshold of unsuccessful authentication attempts. NOTE: The implemented configuration in support of this Part becomes part of the Secure Configuration of the applicable system.	Examples of evidence may include, but are not limited to: • Documentation of the account-lockout parameters; or • Rules in the alerting configuration showing how the system notified individuals after a determined number of unsuccessful login attempts.

C. Compliance

1. **Compliance Monitoring Process:**

1.1. Compliance Enforcement Authority: As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

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

- The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:
- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

1.4. Additional Compliance Information:

None.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change "Control Center" to "control center."	3/24/06
2	9/30/09	Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3	12/16/09	Updated Version Number from -2 to -3 In Requirement 1.6, deleted the sentence pertaining to removing component or system from service in order to perform testing, in response to FERC order issued September 30, 2009.	
3	12/16/09	Approved by the NERC Board of Trustees.	
3	3/31/10	Approved by FERC.	
4	1/24/11	Approved by the NERC Board of Trustees.	

Version	Date	Action	Change Tracking
5	11/26/12	Adopted by the NERC Board of Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.
5	11/22/13	FERC Order issued approving CIP-007-5.	
6	11/13/14	Adopted by the NERC Board of Trustees.	Addressed two FERC directives from Order No. 791 related to identify, assess, and correct language and communication networks.
6	2/15/15	Adopted by the NERC Board of Trustees.	Replaces the version adopted by the Board on 11/13/2014. Revised version addresses remaining directives from Order No. 791 related to transient devices and low impact BES Cyber Systems.
6	1/21/16	FERC order issued approving CIP-007-6. Docket No. RM15-14-000	

The Background, VRF/VSLs, and Guidelines and Technical Basis Sections have been removed for this informal posting. The Project 2016-02 is seeking comments around the concept of the Requirement/Measure language at this time. All other sections will be modified prior to the initial posting.

A. Introduction

1. **Title:** Cyber Security — Configuration Change Management and Vulnerability ~~Assessments~~ Management

2. **Number:** CIP-010-~~4~~3

3. **Purpose:** To prevent and detect unauthorized changes to BES Cyber Systems by specifying configuration change management and vulnerability ~~assessment~~ management requirements in support of protecting BES Cyber Systems from compromise that could lead to misoperation or instability in the Bulk Electric System (BES).

4. **Applicability:**

   4.1. Functional Entities: For the ~~purpose of the~~ requirements in this standard~~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 explicitly 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 Remedial Action Scheme (RAS) where the RAS is subject to one or more requirements in a NERC or Regional Reliability Standard.

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

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

4.1.3. Generator Operator

~~4.1.4.~~ Generator Owner

~~4.1.5.~~4.1.4. ~~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~~in this standard, the following Facilities, systems, and equipment owned by each Responsible Entity in Section 4.1 above are those to which these requirements are applicable. For requirements ~~in this standard~~ where a specific type of Facilities, systems, or equipment or subset of Facilities, systems, and equipment are applicable, these are explicitly 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 RAS where the RAS is subject to one or more requirements in a NERC or Regional Reliability Standard.

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

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

4.2.2. Responsible Entities listed in 4.1 other than Distribution Providers:

All BES Facilities.

4.2.3. Exemptions: The following are exempt from Standard CIP-010-~~3~~4:

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 BES Cyber Systems' Logical Isolation Zones (LIZ).~~discrete Electronic Security Perimeters~~.

~~**4.2.3.2.**~~**4.2.3.3.** Cyber Assets associated with communication networks and data communication links used to extend a Logical Isolation Zone to more than one geographic location.

~~**4.2.3.3.**~~**4.2.3.4.** 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.**~~**4.2.3.5.** For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

~~**4.2.3.5.**~~**4.2.3.6.** Responsible Entities that identify that they have no BES Cyber Systems categorized as high impact or medium impact according to the CIP-002-5 identification and categorization processes.

5. Effective Date:

See Implementation Plan for ~~Project 2016-03~~CIP-010-4.

B. Requirements and Measures

R1. Each Responsible Entity shall implement one or more documented process(es) to mitigate the risk posed by insecure system configuration that collectively include each of the applicable requirement parts in *CIP-010-~~3~~4 Table R1 – Secure Configuration ~~Change~~ Management*.

M1. Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-010-~~3~~4 Table R1 – Secure Configuration ~~Change~~ Management* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-010-~~3~~4 Table R1 – Secure Configuration ~~Change~~ Management			
Part	**Applicable Systems**	**Requirements**	**Measures**
~~1.1~~	~~High Impact BES Cyber Systems and their associated:~~ ~~1. EACMS;~~ ~~2. PACS; and~~ ~~3. PCA~~ ~~Medium Impact BES Cyber Systems and their associated:~~ ~~1. EACMS;~~ ~~2. PACS; and~~ ~~3. PCA~~	~~Develop a baseline configuration, individually or by group, which shall include the following items:~~ ~~1.1.1. Operating system(s) (including version) or firmware where no independent operating system exists;~~ ~~1.1.2. Any commercially available or open-source application software (including version) intentionally installed;~~ ~~1.1.3. Any custom software installed;~~ ~~1.1.4. Any logical network accessible ports; and~~ ~~1.1.5. Any security patches applied.~~	~~Examples of evidence may include, but are not limited to:~~ ~~• Documentation A spreadsheet identifying the required items of the baseline secure configuration for each Cyber Assetsystem, individually or by group.; or~~ ~~A record in an asset management system that identifies the required items of the baseline configuration for each Cyber Asset, individually or by group.~~

1.12	High Impact BES Cyber Systems and their associated: 1. EACMS; 2. PACS; and 3. PCSA Medium Impact BES Cyber Systems and their associated: 1. EACMS; 2. PACS; and 3. PCSA	Control change to the Ssecure Cconfiguration described in CIP-010 Requirement R1 Part 1.1 implemented on systems through: Authorize and document changes that deviate from the existing baseline configuration. 1.1.1. 1.1.1. Authorization; 1.1.2. Prior to the change, determine required cyber security controls in the Secure Configuration that could be impacted by the change; 1.1.3. Implementation; and 1.1.4. Following the change, verify that required cyber security controls determinedcontrols determined in 1.1.2 are not adversely affected; and document the results. : The process requirements of Parts 1.1.1 through 1.1.4 and timeline are based on the analysis of the risk to BES reliability and the risk posed by the change to the system(s).	Examples of evidence may include, but are not limited to: • A change request record and Rrecords forof authorizationassociated electronic authorization (performed by the individual or group with the authority to authorize the change) in a change management system for each change; or • Records of testingcontrols impact evaluatonevaluation; • Records of implementation; and • Records of evaluationverification. Documentation that the change was performed in accordance with the requirement.

CIP-010-~~3~~4 Table R1 – Secure Configuration ~~Change~~ Management			
Part	**Applicable Systems**	**Requirements**	**Measures**
~~1.3~~	~~High Impact BES Cyber Systems and their associated:~~ ~~EACMS;~~ ~~PACS; and~~ ~~PCA~~ ~~Medium Impact BES Cyber Systems and their associated:~~ ~~EACMS;~~ ~~PACS; and~~ ~~PCA~~	~~For a change that deviates from the existing baseline configuration, update the baseline configuration as necessary within 30 calendar days of completing the change.~~	~~An example of evidence may include, but is not limited to, updated baseline documentation with a date that is within 30 calendar days of the date of the completion of the change.~~
~~1.4~~	~~High Impact BES Cyber Systems and their associated:~~ ~~1. EACMS;~~ ~~2. PACS; and~~ ~~3. PCA~~ ~~Medium Impact BES Cyber Systems and their associated:~~ ~~1. EACMS;~~ ~~2. PACS; and~~ ~~3. PCA~~	~~For a change that deviates from the existing baseline configuration:~~ ~~Prior to the change, determine required cyber security controls in CIP-005 and CIP-007 that could be impacted by the change;~~ ~~Following the change, verify that required cyber security controls determined in 1.4.1 are not adversely affected; and~~ ~~Document the results of the verification.~~	~~An example of evidence may include, but is not limited to, a list of cyber security controls verified or tested along with the dated test results.~~

1.25	High Impact BES Cyber Systems	Where technically feasible, fFor each change that deviates from the existing baseline implemented Secure Ceonfiguration, perform the following, per system capability, except during CIP Exceptional Circumstances: 1.2.1. Prior to implementing any change in the production environment, test the changes in a test environment; or -test the changes test the changes in a production environment where the test is performed in a manner that minimizes adverse effects, that models the baseline Secure Ceonfiguration to ensure that required cyber security controls in CIP-005 and CIP-007 are not adversely affected; and 1.2.22.3 Document the results of the testing and,- and, iif a test environment was used, the differences between the test environment and the production environment, including a description of the measures used to account for any differences in operation	An example of evidence may include, but is not limited to, a list of tested cyber security controls, test dates, tested along with successful test results, and and a list of differences between the production and test environments including with descriptions of how any differences in the test and production environments were addressed.accounted for how any differences were accounted for., including of the date of the test.

CIP-010-~~4~~3 Table R1 – ~~Secure~~ Configuration ~~Change~~ Management			
Part	**Applicable Systems**	**Requirements**	**Measures**
		between the test and production environments.	
1.~~3~~6	High Impact BES Cyber Systems Medium Impact BES Cyber Systems Note: Implementation does not require the Responsible Entity to renegotiate or abrogate existing contracts (including amendments to master agreements and purchase orders). Additionally, the following issues are beyond the scope of Part 1.~~3~~6: (1) the actual terms and conditions of a procurement contract; and (2) vendor performance and adherence to a contract.	Prior to a change that deviates from the existing ~~baseline~~ Secure C~~c~~onfiguration associated with installing or updating ~~baseline CIP-007-7 R2 and CIP-010-4 R3 Part 3~~operating system, firmware, and software~~.6secure configuration items in Parts 1.1.1, 1.1.2, and 1.1.5,~~ and when the method to do so is available to the Responsible Entity from the software source: 1.~~3~~6.1. Verify the identity of the software source; and 1.~~3~~6.2. Verify the integrity of the software obtained from the software source.	An example of evidence may include, but is not limited to a change request record that demonstrates the verification of identity of the software source and integrity of the software was performed prior to the ~~baseline~~ Secure Configuration change or a process which documents the mechanisms in place that would automatically ensure the identity of the software source and integrity of the software.

R2. Each Responsible Entity shall implement one or more documented process(es) to mitigate the risk posed by unauthorized change to Secure Configurations that collectively include each of the applicable requirement parts in *CIP-010-~~4~~3 Table R2 – Secure Configuration Monitoring.*

M2. Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-010-~~4~~3 Table R2 – Secure Configuration Monitoring* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-010-~~3~~4 Table R2 – Secure Configuration ~~Monitoring~~			
Part	**Applicable Systems**	**Requirements**	**Measures**
2.1	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; and 2. PCS~~A~~	Use one or a combination of the following methods to monitor the implemented Secure Configuration (per system capability): ~~Monitor at least once every 35 calendar days for changes to the baseline configuration (as described in Requirement R1, Part 1.1). Document and investigate detected unauthorized changes.~~ • Hash monitoring; • Configuration monitoring; • Configuration auditing; or • Other method(s) to mitigate the risk posed by unauthorized change to Secure Configurations. The process requirements of Part 2.1 and timeline are based on the analysis of the risk to BES reliability and the impact rating of the applicable system(s).	An example of evidence may include, but is not limited to, logs from a system that is monitoring the configuration along with records of investigation for any unauthorized changes that were detected.
2.2	High Impact BES Cyber Systems and their associated:	Investigate and remediate detected unauthorized changes to the	An example of evidence may include, but is not limited to, records of

CIP-010-~~3~~4 Table R2 – Secure Configuration ~~Monitoring~~			
Part	**Applicable Systems**	**Requirements**	**Measures**
	1. EACS; and 2. PCS	implemented Secure Configuration found through implementation of Requirement R2 Part 2.1. The process requirements of Part 2.2 and timeline are based on the analysis of the risks to BES reliability and the risks posed by the detected unauthorized change to the implemented Secure Configuration	unauthorized change investigations and remediating activities.

R3. Each Responsible Entity shall implement one or more documented process(es) to mitigate the risk posed by system vulnerabilities that collectively include each of the applicable requirement parts in *CIP-010-~~3~~4 Table R3– Vulnerability ~~Assessments~~Management*.

M3. Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-010-~~4~~3 Table R3 – Vulnerability ~~Assessments~~ Management* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-010-~~3~~4 Table R3 – Vulnerability ~~Assessments~~Management			
Part	**Applicable Systems**	**Requirements**	**Measures**
3.1	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PC~~S~~A Medium Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PC~~S~~A	At least once every 15 calendar months, conduct a paper or active vulnerability assessment.	Examples of evidence may include, but are not limited to: • A document listing the date of the assessment (performed at least once every 15 calendar months), the controls assessed for each BES Cyber System along with the method of assessment; or • A document listing the date of the assessment and the output of any tools used to perform the assessment.

CIP-010-~~4~~3 Table R3 – Vulnerability ~~Assessments~~Management			
Part	**Applicable Systems**	**Requirements**	**Measures**
3.2	High Impact BES Cyber Systems	~~Where technically feasible,~~ Per system capability, at least once every 36 calendar months: 3.2.1 Perform an active vulnerability assessment in a test environment, or perform an active vulnerability assessment in a production environment where the test is performed in a manner that minimizes adverse effects, that models the ~~baseline~~ Secure C~~c~~onfiguration of the BES Cyber System in a production environment; and 3.2.2 Document the results of the testing and, if a test environment was used, the differences between the test environment and the production environment, including a description of the measures used to account for any differences in operation between the test and production environments.	An example of evidence may include, but is not limited to, a document listing the date of the assessment (performed at least once every 36 calendar months), the output of the tools used to perform the assessment, and a list of differences between the production and test environments with descriptions of how any differences were accounted for in conducting the assessment.

CIP-010-~~3~~4 Table R3 – Vulnerability ~~Assessments~~Management			
Part	**Applicable Systems**	**Requirements**	**Measures**
3.3	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; 2. PC~~S~~A	Prior to adding a new ~~applicable~~ Cyber Asset to a production environment, perform an active vulnerability assessment of the new Cyber Asset, except for CIP Exceptional Circumstances~~,~~ and like replacements and additions of the same type of Cyber Asset with a ~~baseline~~ Secure C~~c~~onfiguration that models an existing ~~baseline~~ Secure C~~c~~onfiguration of the previous or other existing Cyber Asset.	An example of evidence may include, but is not limited to, a document listing the date of the assessment (performed prior to the commissioning of the~~-~~ addition~~new Cyber Asset~~) and the output of any tools used to perform the assessment.
3.4	High Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PC~~S~~A Medium Impact BES Cyber Systems and their associated: 1. EAC~~M~~S; 2. PACS; and 3. PC~~S~~A	Document the results of the assessments conducted according to Parts 3.1, 3.2, and 3.3 and the action plan to remediate or mitigate vulnerabilities identified in the assessments including the planned date of completing the action plan and the execution status of any remediation or mitigation action items.	An example of evidence may include, but is not limited to, a document listing the results or the review or assessment, a list of action items, documented proposed dates of completion for the action plan, and records of the status of the action items (such as minutes of a status meeting, updates in a work order system, or a spreadsheet tracking the action items).

CIP-010-~~4~~3 Table R3 – Vulnerability ~~Assessments~~Management			
Part	**Applicable Systems**	**Requirements**	**Measures**
3.5	High Impact BES Cyber Systems and their associated: 1. EACS; 2. PACS; and 3. PCS Medium Impact BES Cyber Systems and their associated: 1. EACS; 2. PACS; and 3. PCS	Identify software vulnerabilities using one or more of the following methods: • Vulnerability database monitoring; • Patch source monitoring; • Vulnerability scanning; or • Other method(s) to identify software vulnerabilities. The process of Part 3.5 shall include the periodicity for identifying software vulnerabilities based on the risk to BES reliability and the impact rating of the applicable system(s).	An example of evidence may include, but is not limited to: • Records of vulnerability database monitoring; • Records of patch source monitoring; or • Records of vulnerability scanning.

CIP-010-~~4~~3 Table R3 – Vulnerability ~~Assessments~~Management			
Part	**Applicable Systems**	**Requirements**	**Measures**
3.6	High Impact BES Cyber Systems and their associated: 1. EACS; 2. PACS; and 3. PCS Medium Impact BES Cyber Systems and their associated: 1. EACS; 2. PACS; and 3. PCS	Create or update a plan to mitigate the identified software vulnerabilities from Part 3.5, through one or more of the following: • Implementing security patches; • Applying compensating controls; • System hardening; or • Other method(s) to mitigate software vulnerabilities. The plan for Part 3.6 must include the timeline for mitigating the software vulnerability based on the analysis of the risk posed by the software vulnerability to the applicable systems. NOTE: The implemented configuration in support of this Part becomes part of the Secure Configuration of the applicable system.	An example of evidence may include, but is not limited to: • Records of implemented security patches; • Records of applied compensating controls; • Records of system hardening; or • Records of other methods.

R4. Each Responsible Entity, for its high impact and medium impact BES Cyber Systems and associated Protected Cyber ~~Assets~~Systems, shall implement, except under CIP Exceptional Circumstances, one or more documented plan(s) for Transient Cyber Assets and Removable Media that include the sections in Attachment 1.

M4. Evidence shall include each of the documented plan(s) for Transient Cyber Assets and Removable Media that collectively include each of the applicable sections in Attachment 1 and additional evidence to demonstrate implementation of plan(s) for Transient Cyber Assets and Removable Media. Additional examples of evidence per section are located in Attachment 2. If a Responsible Entity does not use Transient Cyber Asset(s) or Removable Media, examples of evidence include, but are not limited to, a statement, policy, or other document that states the Responsible Entity does not use Transient Cyber Asset(s) or Removable Media.

C. Compliance

1. Compliance Monitoring Process

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

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

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

- Each applicable entity shall retain evidence of each requirement in this standard for three calendar 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 CEA shall keep the last audit records and all requested and submitted subsequent audit records.

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

D. Regional Variances

None.

E. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	11/26/12	Adopted by the NERC Board of Trustees.	Developed to define the configuration change management and vulnerability assessment requirements in coordination with other CIP standards and to address the balance of the FERC directives in its Order 706.
1	11/22/13	FERC Order issued approving CIP-010-1. (Order becomes effective on 2/3/14.)	
2	11/13/14	Adopted by the NERC Board of Trustees.	Addressed two FERC directives from Order No. 791 related to identify, assess, and correct language and communication networks.
2	2/12/15	Adopted by the NERC Board of Trustees.	Replaces the version adopted by the Board on 11/13/2014. Revised version addresses remaining directives from Order No. 791 related to transient devices and low impact

Version	Date	Action	Change Tracking
			BES Cyber Systems.
2	1/21/16	FERC Order issued approving CIP-010-3. Docket No. RM15-14-000	
3	07/20/17	Modified to address certain directives in FERC Order No. 829.	Revised
3	08/10/17	Adopted by the NERC Board of Trustees.	

CIP-010-~~3~~4 - Attachment 1

Required Sections for Plans for Transient Cyber Assets and Removable Media

Responsible Entities shall include each of the sections provided below in their plan(s) for Transient Cyber Assets and Removable Media as required under Requirement R4.

Section 1. Transient Cyber Asset(s) Managed by the Responsible Entity.

1.1. Transient Cyber Asset Management: Responsible Entities shall manage Transient Cyber Asset(s), individually or by group: (1) in an ongoing manner to ensure compliance with applicable requirements at all times, (2) in an on-demand manner applying the applicable requirements before connection to a BES Cyber System, or (3) a combination of both (1) and (2) above.

1.2. Transient Cyber Asset Authorization: For each individual or group of Transient Cyber Asset(s), each Responsible Entity shall authorize:

1.2.1. Users, either individually or by group or role;

1.2.2. Locations, either individually or by group; and

1.2.3. Uses, which shall be limited to what is necessary to perform business functions.

1.3. Software Vulnerability Mitigation: Use one or a combination of the following methods to achieve the objective of mitigating the risk of vulnerabilities posed by unpatched software on the Transient Cyber Asset (per Transient Cyber Asset capability):

- Security patching, including manual or managed updates;
- Live operating system and software executable only from read-only media;
- System hardening; or
- Other method(s) to mitigate software vulnerabilities.

1.4. Introduction of Malicious Code Mitigation: Use one or a combination of the following methods to achieve the objective of mitigating the introduction of malicious code (per Transient Cyber Asset capability):

- Antivirus software, including manual or managed updates of signatures or patterns;
- Application whitelisting; or
- Other method(s) to mitigate the introduction of malicious code.

1.5. Unauthorized Use Mitigation: Use one or a combination of the following methods to achieve the objective of mitigating the risk of unauthorized use of Transient Cyber Asset(s):

- Restrict physical access;
- Full-disk encryption with authentication;
- Multi-factor authentication; or
- Other method(s) to mitigate the risk of unauthorized use.

Section 2. Transient Cyber Asset(s) Managed by a Party Other than the Responsible Entity.

2.1 Software Vulnerabilities Mitigation: Use one or a combination of the following methods to achieve the objective of mitigating the risk of vulnerabilities posed by unpatched software on the Transient Cyber Asset (per Transient Cyber Asset capability):

- Review of installed security patch(es);
- Review of security patching process used by the party;
- Review of other vulnerability mitigation performed by the party; or
- Other method(s) to mitigate software vulnerabilities.

2.2 Introduction of malicious code mitigation: Use one or a combination of the following methods to achieve the objective of mitigating malicious code (per Transient Cyber Asset capability):

- Review of antivirus update level;
- Review of antivirus update process used by the party;
- Review of application whitelisting used by the party;
- Review use of live operating system and software executable only from read-only media;
- Review of system hardening used by the party; or
- Other method(s) to mitigate malicious code.

2.3 For any method used to mitigate software vulnerabilities or malicious code as specified in 2.1 and 2.2, Responsible Entities shall determine whether any additional mitigation actions are necessary and implement such actions prior to connecting the Transient Cyber Asset.

Section 3. Removable Media

3.1. Removable Media Authorization: For each individual or group of Removable Media, each Responsible Entity shall authorize:

3.1.1. Users, either individually or by group or role; and

3.1.2. Locations, either individually or by group.

3.2. Malicious Code Mitigation: To achieve the objective of mitigating the threat of introducing malicious code to high impact or medium impact BES Cyber Systems and their associated Protected Cyber ~~Assets~~System, each Responsible Entity shall:

3.2.1. Use method(s) to detect malicious code on Removable Media using a Cyber Asset other than a BES Cyber System or Protected Cyber ~~Assets~~System; and

3.2.2. Mitigate the threat of detected malicious code on Removable Media prior to connecting the Removable Media to a high impact or medium impact BES Cyber System or associated Protected Cyber ~~Assets~~System.

CIP-010-~~3~~4 - Attachment 2

Examples of Evidence for Plans for Transient Cyber Assets and Removable Media

Section 1.1: Examples of evidence for Section 1.1 may include, but are not limited to, the method(s) of management for the Transient Cyber Asset(s). This can be included as part of the Transient Cyber Asset plan(s), part of the documentation related to authorization of Transient Cyber Asset(s) managed by the Responsible Entity or part of a security policy.

Section 1.2: Examples of evidence for Section 1.2 may include, but are not limited to, documentation from asset management systems, human resource management systems, or forms or spreadsheets that show authorization of Transient Cyber Asset(s) managed by the Responsible Entity. Alternatively, this can be documented in the overarching plan document.

Section 1.3: Examples of evidence for Section 1.3 may include, but are not limited to, documentation of the method(s) used to mitigate software vulnerabilities posed by unpatched software such as security patch management implementation, the use of live operating systems from read-only media, system hardening practices or other method(s) to mitigate the software vulnerability posed by unpatched software. Evidence can be from change management systems, automated patch management solutions, procedures or processes associated with using live operating systems, or procedures or processes associated with system hardening practices. If a Transient Cyber Asset does not have the capability to use method(s) that mitigate the risk from unpatched software, evidence may include documentation by the vendor or Responsible Entity that identifies that the Transient Cyber Asset does not have the capability.

Section 1.4: Examples of evidence for Section 1.4 may include, but are not limited to, documentation of the method(s) used to mitigate the introduction of malicious code such as antivirus software and processes for managing signature or pattern updates, application whitelisting practices, processes to restrict communication, or other method(s) to mitigate the introduction of malicious code. If a Transient Cyber Asset does not have the capability to use method(s) that mitigate the introduction of malicious code, evidence may include documentation by the vendor or Responsible Entity that identifies that the Transient Cyber Asset does not have the capability.

Section 1.5: Examples of evidence for Section 1.5 may include, but are not limited to, documentation through policies or procedures of the method(s) to restrict physical access; method(s) of the full-disk encryption solution along with the authentication protocol; method(s) of the multi-factor authentication solution; or documentation of other method(s) to mitigate the risk of unauthorized use.

Section 2.1: Examples of evidence for Section 2.1 may include, but are not limited to, documentation from change management systems, electronic mail or procedures that document a review of installed security patch(es); memoranda, electronic mail, policies or contracts from parties other than the Responsible Entity that identify the security patching process or vulnerability mitigation performed by the party other than the Responsible Entity; evidence from change management systems, electronic mail, system documentation or contracts that identifies acceptance by the Responsible Entity that the practices of the party other than the Responsible Entity are acceptable; or documentation of other method(s) to mitigate software vulnerabilities for Transient Cyber Asset(s) managed by a party other than the Responsible Entity. If a Transient Cyber Asset does not have the capability to use method(s) that mitigate the risk from unpatched software, evidence may include documentation by the Responsible Entity or the party other than the Responsible Entity that identifies that the Transient Cyber Asset does not have the capability.

Section 2.2: Examples of evidence for Section 2.2 may include, but are not limited to, documentation from change management systems, electronic mail or procedures that document a review of the installed antivirus update level; memoranda, electronic mail, system documentation, policies or contracts from the party other than the Responsible Entity that identify the antivirus update process, the use of application whitelisting, use of live of operating systems or system hardening performed by the party other than the Responsible Entity; evidence from change management systems, electronic mail or contracts that identifies the Responsible Entity's acceptance that the practices of the party other than the Responsible Entity are acceptable; or documentation of other method(s) to mitigate malicious code for Transient Cyber Asset(s) managed by a party other than the Responsible Entity. If a Transient Cyber Asset does not have the capability to use method(s) that mitigate the introduction of malicious code, evidence may include documentation by the Responsible Entity or the party other than the Responsible Entity that identifies that the Transient Cyber Asset does not have the capability.

Section 2.3: Examples of evidence for Section 2.3 may include, but are not limited to, documentation from change management systems, electronic mail, or contracts that identifies a review to determine whether additional mitigations are necessary and that they have been implemented prior to connecting the Transient Cyber Asset managed by a party other than the Responsible Entity.

Section 3.1: Examples of evidence for Section 3.1 may include, but are not limited to, documentation from asset management systems, human resource management systems, forms or spreadsheets that shows authorization of Removable Media. The documentation must identify Removable Media, individually or by group of Removable Media, along with the authorized users,

either individually or by group or role, and the authorized locations, either individually or by group.

Section 3.2: Examples of evidence for Section 3.2 may include, but are not limited to, documented process(es) of the method(s) used to mitigate malicious code such as results of scan settings for Removable Media, or implementation of on-demand scanning. Documented process(es) for the method(s) used for mitigating the threat of detected malicious code on Removable Media, such as logs from the method(s) used to detect malicious code that show the results of scanning and that show mitigation of detected malicious code on Removable Media or documented confirmation by the entity that the Removable Media was deemed to be free of malicious code.

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:	Revised by Project 2017-07 Standards Alignment with Registration SAR Drafting Team Stephen Wendling, Chair		
Organization:	American Transmission Company		
Telephone:	(608) 877-8232	Email:	swendling@atcllc.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 will align the Reliability Standards with the outcome of the Risk-Based Registration (RBR) initiative.			
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):			
This project would modify Reliability Standards to be consistent with the FERC-approved changes to registration as part of the RBR initiative.			
Project Scope (Define the parameters of the proposed project):			
This project will review and align Reliability 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 Reliability 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			

[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
(PSEs) and Interchange Authorities (IAs); references to the Load-Serving Entity (LSEs) will be removed or replaced by ~~either the Distribution Provider (DP), the Balancing Authority (BA), or~~ the appropriate functional ~~applicable~~ entity. ~~Additionally, t~~The project will include adding Underfrequency Load Shedding (UFLS)-only Distribution Providers (DPs) to the Applicability ~~Section~~ section of PRC-005 and PRC-006 per NERC registration criteria.~~; and review the Applicability sections of PRC-004 and PRC-008 and revise, as appropriate, to add UFLS-only DPs.~~ Additionally, the project will consider whether to include a definition for UFLS into the NERC Glossary of Terms, as well as review the standards to ensure consistent use of the term Planning Coordinator. 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. For instance, Reliability Standard MOD-032-1 specifies certain data from LSEs that may need to be provided by other functional entities going forward. 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~~-1.1b~~ and PRC-006~~-003~~ will be updated to add UFLS-only DP to the Applicability ~~Sections~~sections. ~~and a review of the Applicability Sections of PRC-004-5(i) and PRC-008-0 to add, as appropriate, UFLS-only DP to align with the post-RBR registration impacts.~~ 3. Initiatives that can address RBR updates through the periodic review process. ~~-~~The 2017-07 SAR drafting team should consider whether it or the periodic review teams currently reviewing those standards should make the necessary revisions. ~~This would include the INT-004-3.1 and NUC-001-3 standards. Rather than the Project 2017-07 making the revisions the SDT could coordinate with the periodic review teams currently reviewing INT-004-3.1 and NUC-001-3 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 Standard Drafting 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):
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):

Requested information
Since LSE is being removed or replaced by either the Distribution Provider (DP), the Balancing Authority (BA), or the appropriate Applicable Entity for the standards that need to be updated, those entities will likely 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.
None
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)?
None
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.

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

[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.

Market Interface Principles	
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
NPCC and SERC	~~UFLS-only DP will be added to the Applicability Section of PRC-006 and will create a variance of the following two~~ Regional Reliability Standards: PRC-006-NPCC-1 PRC-006-SERC-01 PRC-006-SERC-02

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~~December 11, 2017	Standards Information Staff	Revised
3	February 1, 2018	Standards Information Staff	Revised

Standard Authorization Request (SAR) Form

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The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

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Date Submitted:			
SAR Requester			
Name:	Revised by Project 2017-07 Standards Alignment with Registration SAR Drafting Team Stephen Wendling, Chair		
Organization:	American Transmission Company		
Telephone:	(608) 877-8232	Email:	swendling@atcllc.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 will align the Reliability Standards with the outcome of the Risk-Based Registration (RBR) initiative.			
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):			
This project would modify Reliability Standards to be consistent with the FERC-approved changes to registration as part of the RBR initiative.			
Project Scope (Define the parameters of the proposed project):			
This project will review and align Reliability 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 Reliability 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			

[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
(PSEs) and Interchange Authorities (IAs); references to the Load-Serving Entity (LSEs) will be removed or replaced by the appropriate functional entity. The project will include adding Underfrequency Load Shedding (UFLS)-only Distribution Providers (DPs) to the Applicability section of PRC-005 and PRC-006 per NERC registration criteria. Additionally, the project will consider whether to include a definition for UFLS into the NERC Glossary of Terms, as well as review the standards to ensure consistent use of the term Planning Coordinator. 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. For instance, Reliability Standard MOD-032-1 specifies certain data from LSEs that may need to be provided by other functional entities going forward. 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 and PRC-006 will be updated to add UFLS-only DP to the Applicability sections. 3. Initiatives that can address RBR updates through the periodic review process. The 2017-07 SAR drafting team should consider whether it or the periodic review teams currently reviewing those standards should make the necessary revisions.
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 Standard Drafting 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):
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):
Since LSE is being removed or replaced by either the Distribution Provider (DP), the Balancing Authority (BA), or the appropriate Applicable Entity for the standards that need to be updated, those entities will likely 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.
None

[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.

Requested information
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)?
None
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.

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
NPCC and SERC	Regional Reliability Standards: PRC-006-NPCC-1 PRC-006-SERC-01 PRC-006-SERC-02

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

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1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	December 11, 2017	Standards Information Staff	Revised
3	February 1, 2018	Standards Information Staff	Revised

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Technical Justifications

Project 2018-03 Standards Efficiency Review Retirements

Purpose: The purpose of the Project 2018-03 – Standards Efficiency Review Retirements Technical Justifications document was for the Standards Drafting Team (SDT) to evaluate each recommendation for retirement identified in the Standards Authorization Request (SAR). It is intended to facilitate understanding about the technical rationale for each recommendation proposed by the SDT.

Technical Justifications for Phase I of Standards Efficiency Review - Retirements

BAL-005-1, Requirements R4 and R6
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retain
Rationale
The SDT believes these requirements should be retained for the following reasons:
Requirements R4 and R6 of BAL-005-1 are requirements specific to the calculation of the Area Control Error (ACE). TOP-010-1(i) Requirement R2 covers ACE with the wording of "…analysis functions and Real-time monitoring…" but does not cover specifics, such as: quality flags for missing or invalid data that is part of BAL-005-1, Requirement R4 or the accuracy of scan rates that is part of BAL-005-1, Requirement R6.

In TOP-010-1(i), Requirement R2 (revised from TOP-010-1) covers the calculation and monitoring of ACE, however, the language: "Each Balancing Authority shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring," is only addressing quality. In BAL-005-1 (revised from BAL-005-0.2b) Requirement R4 states: "The Balancing Authority shall make available to the operator information associated with Reporting ACE including, but not limited to, quality flags indicating missing or invalid data." Requirement R6 of BAL-005-1 states: "Each Balancing Authority that is within a multiple Balancing Authority Interconnection shall implement an Operating Process to identify and mitigate errors affecting the accuracy of scan rate data used in the calculation of the Reporting ACE for each Balancing Authority Area." Both of these requirements are specific to identifying missing or invalid data plus scan rates, not just the quality of the Real-time data.

The Standards Efficiency Review – Retirements (SER Phase I) team will communicate with the Standards Efficiency Review Phase II team regarding Requirements R4 and R6 of BAL-005-1 to determine if there is opportunity for revisions to TOP-010-1(i), Requirement R2 that would satisfy the missing or invalid data plus scan rates. If the Standards Efficiency Review Phase II team takes an approach for such determinations and then finds that there is that opportunity, then Requirements R4 and R6 of BAL-005-1 may be able to be looked at for retirement within that project or within a future project.

COM-002-4, Requirement R2
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retain
Rationale
The SDT believes this requirement should be retained for the following reasons:
While training on communications protocols would fall into an entity's systematic approach to training, the requirements do not explicitly mandate training on communications protocols. It is essential for all operators to have a common level of understanding and be trained in three-part communication. During development of COM-002-4, it was determined that because PER-005 would not meet the NERC Board of Trustees (BOT) November 7, 2013 Resolution to mandate training, that SDT included a requirement to conduct initial training in order to ensure that a baseline of training is complete before an individual is placed in a position to use the communications protocols. Requiring initial training is not overly burdensome to an entity and any subsequent training can be covered in PER-005 or through the operator feedback loop as determined by the entity.

The SER Phase I team will communicate with the Standards Efficiency Review Phase II team regarding Requirement R2 of COM-002-4 to determine if there is opportunity for revisions to PER-005-2, Requirement R2 that would satisfy the training requirements specific to training on communications protocols. If the Standards Efficiency Review Phase II team takes an approach for such determinations and then finds that there is that opportunity, then Requirement R2 of COM-002-4 may be able to be looked at for retirement within that project or within a future project.

EOP-005-3, Requirement R8
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retain
Rationale
The SDT believes this requirement should be retained for the following reasons:
The PER-005 standard entails training processes, however it is does not specifically provide for system restoration training. In PER-005-2, the requirement to provide system restoration training no longer exists. In fact, the rationale to remove the minimum training requirement specific to system restoration from PER-005-1 was, in part, based on the existence of former Requirement R10 in EOP-005-2 (Requirement R8 of EOP-005-3) and Requirement R9 in EOP-006-2 (Requirement R7 of EOP-006-3). If Requirement R8 in EOP-005-3 is removed, then there will not be any requirements to provide system restoration training to operating personnel in any of the standards.

A specific requirement for system restoration training should be maintained because, while a system shutdown is a low probability, it could have a high impact if not done properly. The SER Phase I team will communicate with the Standards Efficiency Review Phase II team regarding Requirement R8 of EOP-005-3 to determine if there is opportunity for revisions to PER-005-2 that would satisfy the training requirements specific to system restoration training. If the Standards Efficiency Review Phase II team takes an approach for such determinations and then finds that there is that opportunity, then Requirement R8 of EOP-005-3 may be able to be looked at for retirement within that project or within a future project.

EOP-006-3, Requirement R7
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retain
Rationale
The SDT believes this requirement should be retained for the following reasons:
The PER-005 standard entails training processes, however it is does not specifically provide for system restoration training. In PER-005-2, the requirement to provide system restoration training no longer exists. In fact, the rationale to remove the minimum training requirement specific to system restoration from PER-005-1 was, in part, based on the existence of former Requirement R9 in EOP-006-2 (Requirement R7 of EOP-006-3). If Requirement R7 in EOP-006-3 is removed, then there will not be any requirements to provide system restoration training to operating personnel in any of the standards.

A specific requirement for system restoration training should be maintained because, while a system shutdown is a low probability, it could have a high impact if not done properly. A specific requirement for system restoration training should be maintained because, while a system shutdown is a low probability, it could have a high impact if not done properly. The SER Phase I team will communicate with the Standards Efficiency Review Phase II team regarding Requirement R7 of EOP-006-3 to determine if there is opportunity for revisions to PER-005-2 that would satisfy the training requirements specific to system restoration training. If the Standards Efficiency Review Phase II team takes an approach for such determinations and then finds that there is that opportunity, then Requirement R7 of EOP-006-3 may be able to be looked at for retirement within that project or within a future project.

FAC-008-3, Requirements R7 and R8
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retire
Rationale
The SDT believes these requirements should be retired for the following reasons:
These requirements are duplicative of the data provision standards MOD-032-1, IRO-010-2, and TOP-003-3. In MOD-032-1, Requirement R1, the Planning Coordinator (PC) and Transmission Provider (TP) develop modeling data requirements and reporting according to Attachment 1. In MOD-032-1 R2, the Transmission Operator (TO) and Generator Operator (GO) provide power capabilities data in Item 3, and facility ratings data in Items 3(f), 4(c) and 6(g) in the steady-state column of Attachment 1, as requested by the TP or PC.

IRO-010-2, Requirement R1 and TOP-003-3, Requirement R1 require the Reliability Coordinator (RC) and the Transmission Operator (TOP) to list necessary data and information needed to perform its Operating Planning Analyses and Real-Time Assessments. This data necessarily includes facility ratings as inputs to SOL monitoring. IRO-010-2, Requirement R3 and TOP-003-3, Requirement R5 require that the TO and the GO to respond to the RC's and the TOP's requests.

FAC-013-2 Requirements R1, R2, R4, R5 and R6 (all)
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retire
Rationale
The SDT believes this standard should be retired for the following reasons:
The requirement for Planning Coordinators (PC) to have a methodology for and to perform an annual assessment of Transfer Capability for a single year in the Near-Term Transmission Planning Horizon does not benefit System reliability beyond that provided by other Reliability Standards. This Reliability Standard is primarily administrative in nature and does not require specific performance metrics or coordination among functional entities. In general, FAC-013-2 fails to meet System reliability objectives in the following ways:

- Assessing transfer capability above the "known commitments for Firm Transmission Service and Interchange" required by TPL-001-4 (R1.1.5), serves a market function as opposed to securing System reliability.
- Individual PCs develop their own methodologies that may be very disparate from each other.
- Impacted functional entities, such as TP, do not have meaningful input into the methodology or analysis.
- The standard does not specify performance metrics or define what acceptable system performance is.
- Entities that receive the methodology or assessment results are not obligated to use or even consider the information in their assessments.
- Requirement R4 only requires the assessment to be performed for one year in the Near-Term Transmission Planning Horizon. This year can be arbitrarily chosen by the PC and the analysis does not guarantee transmission service that is necessary for System reliability.

Assessing transfer capability in the planning horizon is a method to test the robustness of the system. Robustness testing of a system is not an indicator of reliability because there is no metric for robustness. Additionally, the proposed retirement of FAC-013-2 does not preclude any entity from performing studies to assess transfer capability for their own purposes. The reliability benefit of doing such an assessment varies from entity to entity, with some entities not having a benefit for the assessment it at all. The 2013 NERC Independent Experts Review Project (IERP) identified Requirements R2 and R3 as administrative and recommended them for retirement. Requirement R3 was approved for retirement by FERC in 2014.

INT-004-3.1 Requirements R1, R2 and R3 (all)
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retire
Rationale
The SDT believes this standard should be retired for the following reasons:
INT-004-3.1 may be retired since it satisfies Paragraph 81 Criteria 'B6 – Commercial or Business Practice.' Interchange scheduling and congestion are elements that impact transmission costs, rather than actual reliable management of the BES. Furthermore, the applicable entity for Requirements R1 and R2, the Purchasing-Selling Entity, has been removed from the list of NERC Functional Entities, supporting the

market-based observations herein. Requirement R3 specifically refers to "Pseudo-Ties that are included in the NAESB Electric Industry Registry," reinforcing the tie to North American Energy Standards Board (NAESB) Wholesale Electric Quadrant (WEQ) Business Practice Standards.

INT-006-4, Requirements R3.1, R4, and R5
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retire
Rationale
The SDT believes these requirements should be retired for the following reasons:
INT-006-4, Requirement R3 Part 3.1 can be retired under Paragraph 81, Criterion A. There is no substantive impact on reliability with requiring the RC to be notified when a Reliability Adjustment Arranged Interchange has been denied.

INT-006-4, Requirement R4 can be retired under Paragraph 81, Criteria A and B7. Covered in North American Energy Standards Board (NAESB) e-Tagging specifications, Section 1.6.3.1 and Section 1.3, Request State. This requirement outlines the conditions that must exist for an Arranged Interchange to transition to Confirmed Interchange. NAESB Electronic Tagging Specification Section 1.6.3.1 and Section 1.3, Request State, stipulate these exact requirements. INT-006-4, Requirement R4 is being recommended for retirement, the requirement is accomplished through a Balancing Authority's (BA) e-Tag Authority Service and does not have an impact on reliability.

INT-006-4, Requirement R5 can be retired under Paragraph 81, Criteria A and B7. This is covered in NAESB e-Tagging specifications, Section 1.6.4. This requirement outlines who is notified when the transition to Confirmed Interchange occurs. NAESB Electronic Tagging Specification, Section 1.6.4, stipulate these exact requirements. INT-006-4, Requirement R5 is being recommended for retirement, the requirement is accomplished through a BA's e-Tag Authority Service and does not have an impact on reliability.

INT-009-2.1, Requirement R2
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retire
Rationale
The SDT believes this requirement should be retired for the following reasons: This requirement can be retired under Paragraph 81, Criterion B7, as the requirement is redundant with approved NERC Reliability Standard BAL-005-1, Requirement R7.

INT-010-2.1 Requirements R1, R2 and R3 (all)
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retire
Rationale
The SDT believes this standard should be retired for the following reasons:
The opportunity exists to retire Reliability Standard INT-010-2.1 in its entirety. INT-010-2.1, Requirement R1: (1) Retire under Paragraph 81, Criteria B6 and B7 and (2) the IERP also recommended for retirement. More stringent tagging requirements already exist in NAESB WEQ-004-1. Therefore, this requirement is

duplicative and does little, if anything, to benefit or protect the reliable operation of the Bulk Electric System (BES).

INT-010-2.1, Requirement R2: (1) Retire under Paragraph 81, Criteria B6 and B7 and (2) the IERP also recommended for retirement. More stringent tagging requirements already exist in NAESB WEQ 004-8. Therefore, this requirement is duplicative and does little, if anything, to benefit or protect the reliable operation of the BES.

INT-010-2.1, Requirement R3: (1) Retire under Paragraph 81, Criteria B6 and B7 and (2) the IERP also recommendation for retirement. More stringent tagging requirements already exist in NAESB WEQ 004-1. Therefore, this requirement is duplicative and does little, if anything, to benefit or protect the reliable operation of the BES.

IRO-002-5, Requirements R1, R4 and R6:
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retire Requirement R1, Retain Requirements R4 and R6
Rationale
The SDT believes that Requirement R1 should be retired for the following reasons:
Requirement R1 of IRO-002-5 is redundant to other requirements in the IRO family of standards. The requirement is a control for aiding compliance with IRO-008-2, Requirement R1 related to the performance of an Operational Planning Analysis (OPA), and it is duplicative to Requirement R3 in IRO-010-2. The purpose of IRO-010-2 is to ensure adequate data is collected so that reliability is not adversely impacted by preventing instability, uncontrolled separation, or Cascading outages and is applicable to all functional entities in the RC area. The purpose of IRO-008-2 is for the RC to perform the analysis to prevent instability, uncontrolled separation, or Cascading and with the data collected per IRO-010-2. The data exchange capabilities are indicated in IRO-010-2, Requirement R3, which includes BAs and TOPs, and IRO-008-2, Requirement R1 requires the RC to perform the OPA, which makes IRO-002-5, Requirement R1 redundant with the aforementioned standards and requirements.

IRO-010-2 requires the RC to identify the data it needs to perform its OPA (R1), which entities need to provide such data (R2), and then obligates those registered entities to then supply the data (R3). For an entity to comply with IRO-010-2, Requirement R3, it must be able to exchange data with the requesting RC. Additionally, to comply with IRO-008-2, Requirement R1, the RC must have received all of the data it needs to perform the OPA. Finally, Measure M1 for IRO-002-5, Requirement R1 states that an entity needs to have documentation describing its data exchange capabilities with other entities, which is administrative in nature. As such, the IRO-002-5, Requirement R1 is not needed to support reliability and can be retired.

The SDT believes that Requirements R4 and R6 should be retained for the following reasons:
IRO-002-5, Requirements R4 and R6 are necessary for the Real-time operators to be assured of having the tools necessary to monitor the BES; therefore, retirement of these requirements is not being sought during this phase of the project.

Requirement R4 of IRO-002-5 needs to be retained to make it clear that the System Operator has authority to postpone, cancel or recall planned outages of Energy Management System (EMS), Internet Technology (IT), or communications-related equipment. Although some RCs may include this type of equipment in their outage coordination process (cf. IRO-017-1), the inclusion of EMS, IT or communications-related equipment is not explicitly required by IRO-017-1, Requirement R1. In addition, RC equipment outages are not required to follow the RC's outage coordination process (i.e., IRO-017-1, Requirement R2 is only applicable to TOPs and BAs). As such, a potential gap in the standards would exist if IRO-002-5, Requirement R4 was retired.

IRO-008-2, Requirement R6
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retain
Rationale
The SDT believes this requirement should be retained for the following reasons:
Although IRO-008-2, Requirement R6 appears to be administrative in nature, there are reliability benefits to knowing what actions were taken to prevent or mitigate the exceedance. Therefore, retirement of IRO-008-2, Requirement R6 is not being sought during this phase of the project.

IRO-014-3, Requirement R3
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retain
Rationale
The SDT believes this requirement should be retained for the following reasons:
The reliability objective of "notification" is mandated as a part of the RC having and implementing Operating Procedures, Operating Processes, or Operating Plans that include criteria and processes for notifications (Requirement R1, Part 1.1), this ensures RC operations are coordinated to maintain reliability of the BES. As such, a separate requirement for ensuring notifications are made to impacted RCs is duplicative. However, IRO-014-3, Requirement R1 time horizon would need to be revised to a time horizon of "Real-time" if Requirement R3 were to be retired. Revision of Requirement R1 is outside the scope of the project, so retirement of IRO-014-3, Requirement R3 is not being sought during this phase of the project.

SER Phase I team will communicate with the Standards Efficiency Review Phase II team regarding Requirement R3 of IRO-014-3 to determine if there is opportunity for revision to IRO-014-3, Requirement R1 that would satisfy the revision of the time horizon to "Real-time." If the Standards Efficiency Review Phase II team takes an approach for such determinations and then finds that there is that opportunity, then Requirements R3 of IRO-014-3 may be able to be looked at for retirement within that project or within a future project.

IRO-017-1, Requirement R3
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retain
Rationale
The SDT believes this requirement should be retained for the following reasons:
IRO-017-1 is not entirely duplicative of TPL-001-4, Requirement R8. The RC should be added as a named recipient to TPL-001-4 prior to considering IRO-017-1, Requirement R3 for retirement.
SER Phase I team will communicate with the Standards Efficiency Review Phase II team regarding Requirement R3 of IRO-017-1 to determine if there is opportunity for revisions to TLP-001-4 that would satisfy the adding the RC as a named recipient. If the Standards Efficiency Review Phase II team takes an approach for such determinations and then finds that there is that opportunity, then Requirement R3 of IRO-017-1 may be able to be looked at for retirement within that project or within a future project.

MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-2a, MOD-030-3, MOD-001-1a and proposed MOD-001-2
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retire
Rationale
The SDT believes these standards should be retired for the following reasons:
Available Transfer Capability (ATC)/Available Flowgate Capability (AFC), as well as eTags, are commercially-focused elements, facilitating interchange and balancing of interchange. The Real-time system operators are ambivalent of these commercial arrangements, as they must maintain reliability of the BES according to System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs). If a scheduled interchange would violate SOLs or IROLs, the Real-time operators must disregard the scheduled interchange and operate the system to its actual reliability limits. This observation is reinforced by NERC's statement in the 2015 filing related to risk-based reliability proposing removal of the Interchange Authority from the compliance registry, where it's stated: "NERC proposes to remove interchange authorities as functional entities, explaining that the activities of the interchange authority are commercial in nature and, thus, the removal will have little if any impact on reliability of the bulk electric system." FERC acknowledged this in their March 15, 2015 Order, where they stated: "…we approve NERC's proposed removal of the interchange authority as a functional entity. As explained by NERC, the interchange authority performs a commercial function, essentially quality control activity in verifying and communicating interchange schedules."

MOD-020-0, Requirement R1 (all)
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retire
Rationale
The SDT believes this standard should be retired for the following reasons:
MOD-031-2 and IRO-010-2 do give the necessary entities the authority to request relevant information nor does MOD-031-2 and IRO-010-2 require the associated entities to provide that information. Demand-Side Management (DSM) data is necessarily related to the near-term operating time horizon, as well as the planning time horizons, but not to the Real-time operating time horizon that the RC and TOP are operating in. According to TOP-001-4, Requirements R1 and R2, and IRO-001-4, Requirement R1, the RC,

BA and TOP must operate the BES according to SOLs and IROLs, and do not generally have control over DSM. They do have the authority to issue Operating Instruction to other entities as needed to maintain BES reliability within SOLs and IROLs; the entities receiving Operating Instructions are obligated, per TOP-001-4, Requirement R3, to follow those instructions, subject to the exceptions noted within that requirement. Further, the Demand Response Availability Data System (DADS) collects and disseminates data regarding Demand Response programs according to Section 1600 of the NERC Rules of Procedure. All entities identified in MOD-020-0 R1 are sources of DADS data, have access to DADS data, or both.

DSM and Direct Control Load Management (DLCM) may be regarded as long-term-planning and operations-planning time horizon resources, but, particularly with a "on request within 30 calendar days" obligation in the requirement, is not a resource for the Real-time or day-ahead operating time horizon for Reliability Coordinators and Transmission Operators, which must plan to operate, and actually operate, the BES within SOLs and IROLs, a subset of SOLs. In addition, the amount of interruptible demands and DLCM at the TP, Resource Planner (RP), and/or Load-Serving Entity (LSE) (which has been removed from the compliance registry and is no longer obligated to comply with NERC standards) level is not of locational benefit to TOPs and RCs to assist them in operating within SOLs, as such information, were it to be provided within a usable time frame, would not be sufficiently granular to assist the TOP and RC. All meaningful information regarding interruptible demands and DLCM is available from DADS, which, in the United States, is a mandatory reporting mechanism, regulated per Section 1600 of the NERC Rules of Procedure. DSM and DLCM are financially-enabled mechanisms whereupon RPs may encourage customers and customer groups to permit local control of their load in exchange for rate considerations. And this local control may or may not be sited in such a manner to provide any benefit to TOPs and RCs; which, again, are obligated by NERC Standards to operate the BES within SOLs.

PRC-004-5(i), Requirement R4
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retire
Rationale
The SDT believes this requirement should be retired for the following reasons:
The standard's purpose is to identify and correct the causes of Misoperations of Protection Systems for BES Elements. The Reliability Standard's Guideline and Technical Basis for Requirement R4 considers due diligence that an entity must make in determining the cause of a Protection System Misoperation.

The compliance activities associated with this requirement fall into tracking of milestones and do not improve reliability. Requirement R4 acts as a control to support compliance with Requirements R1 and R3. It is in the best interest of the entity to continue to investigate and detect whether its Protection System components caused a Misoperation and develop a corrective plan for the identified Protection System component. This can be achieved through the entity's internal control policies and procedures engineered to maximize efficiency and reliability. Entities endeavor to determine the cause of a Misoperation, and doing so may take extended time if equipment outages are necessary. However, if an entity is unable to determine the cause, further investigation(s) using the same event data are unlikely to lead to identification of the cause. Proposed retirement of Requirement R4 does not preclude the entity's

responsibility to continue the investigation to identify the cause of Misoperation. However, it does alleviate the need to keep tracking documents for the sake of showing investigative actions.

PRC-015-1 Requirements R1, R2, and R3 (all)
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retain
Rationale
The SDT believes this standard should be retained for the following reasons:
PRC-015-1 is scheduled to be retired on 12/31/2020 under the PRC-012-2 Implementation Plan (IP).

PRC-018-1 Requirements R1, R2, R3, R4, R5 and R6 (all)
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retain
Rationale
The SDT believes this standard should be retained for the following reasons:
PRC-018-1 is superseded by PRC-002-2 in Year 2022. The PRC-002-2 IP states: "Standard PRC-018-1 shall remain effective throughout the phased implementation period of PRC-002-2…"

TOP-001-4 Requirements R16, R17, R19 and R22
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retain Requirements R16 and R17, Retire Requirements R19 and R22
Rationale
The SDT believes Requirements R16 and R17 should be retained for the following reasons:
Requirements R16 and R17 of TOP-001-4 need to be retained to make it clear that the System Operator has authority to postpone, cancel or recall planned outages of EMS, IT or communications-related equipment. Although some RCs may include this type of equipment in their outage coordination process (IRO-017-1), the inclusion of EMS, IT or communications-related equipment is not explicitly required by IRO-017-1, Requirement R1. As such, a potential gap in the standards would exist if TOP-001-4, Requirements R16 and R17 were retired. Requirements R16 and R17 are necessary for the Real-time operators to be assured of having the tools necessary to monitor the BES. Therefore, retirement of TOP-001-4, Requirements R16 and R17 is not being sought during this phase of the project.

The Purpose of TOP-003-3 is to ensure adequate data is collected by the BA and TOP to fulfill their operational and planning responsibilities. The Purpose of TOP-002-4 is to ensure each BA and TOP have plans to operate within specified limits using the data provided in TOP-003-3. The data exchange capabilities that are indicated in TOP-001-4, Requirements R19 and R22 for the BA and TOP are redundant with TOP-003-3, Requirements R3, R4 and R5 and TOP-002-4, Requirement R1.

The SDT believes Requirements R19 and R22 should be retired for the following reasons:
TOP-001-4, Requirement R19 is redundant to other requirements in the TOP family of standards. For TOPs, the existing TOP-003-3, Requirement R5 cannot be fulfilled by entities unless data exchange capabilities exist between the TOP and the supplying entities. Similarly, TOP-002-4, Requirement R1

cannot be fulfilled by the TOP unless the data needed to perform the OPA has been received from the supplying entities (i.e., data had to be exchanged). As such, Requirement R19 in TOP-001-4 is not needed to support reliability and can be retired.

TOP-001-4, Requirement R22 is redundant to other requirements in the TOP family of standards. For the BA, the existing TOP-003-3, Requirement R5 cannot be fulfilled by entities unless data exchange capabilities exist between the BA and the supplying entities. Similarly, TOP-002-4, Requirement R4 cannot be fulfilled by the BA unless the data needed to develop its Operating Plan for next-day operations has been received from the supplying entities (i.e., data had to be exchanged). As such, Requirement R22 in TOP-001-4 is not needed to support reliability and can be retired.

VAR-001-5*, Requirements R2 and R3
SAR Recommendation: Retire
Project 2018-03 SDT Recommendation: Retire Requirement R2, Retain Requirement R3
Rationale
The SDT believes Requirement R2 should be retired for the following reasons:
VAR-001-5, Requirement R2 is duplicative with the existing requirements in the TOP-001-4 and TOP-002-4, which direct the TOP to plan and operate within in SOL values, which includes system voltage limits. TOP-002-4, Requirement R1 requires an OPA to be completed to ensure no SOL is violated, and TOP-001-4, Requirement R10 provides the criteria that the TOP shall use for determining SOL exceedances, which includes monitoring voltages. If an SOL violation is identified, then the TOP shall have an Operating Plan to mitigate the violation. TOP-001-4 and TOP-002-4 requirements direct the TOP to maintain reliability of the BES and to mitigate SOL exceedances. If the TOP identifies no SOLs, voltage or otherwise, then the TOP has enough resources "scheduled" to maintain reliability of its BES. The remaining VAR-001-4.2 requirements ensure that a TOP ensures voltage, reactive flows, and reactive resources are monitored, controlled, and maintained with limits. The FAC family of standards ensure the proper BES Facilities and/or Elements are built with applicable equipment and system ratings.

TOP-002-4, Requirement R1 thus requires the TOP to have an OPA that assess whether its next-day planned operations will exceed any SOLs, and TOP-001-4, Requirement R10 thus requires that the TOP monitor its Facilities and thus determine SOL exceedances. Further, TOP-001-4, Requirement R14 requires that the TOP "…initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment…" and TOP-001-4, Requirement R1 requires that the TOP "…shall act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions."

Since operating outside voltage limits represents a SOL exceedance, the TOP must have an OPA that assesses whether its next-day operations will exceed SOLs. The TOP has the obligation to initiate an Operating Plan to mitigate an SOL exceedance, and has the responsibility to take any actions under its control and issue Operating Instructions, if needed. The responsibilities elucidated in VAR-001-4.1, Requirement R2 are fully addressed in these other standards; scheduling sufficient reactive resources to regulate voltage levels under normal and Contingency conditions is one of several vital elements of addressing this obligation.

The SDT believes Requirement R3 should be retained for the following reasons:
For reliability purposes, the TOP must ensure sufficient voltage support is provided in Real-time in order to operate within an SOL to prevent voltage-collapse events wherein the operation within SOLs/IROLs itself is not adequate to assure stable voltage operations in both steady-state and transient conditions. The TOP-series of standards does not provide sufficient granularity to assure that adequate voltage/reactive resources, both of magnitude and type, are operated to voltage and reactive flow as necessary.

* VAR-001-4.2, is an inactive standard. VAR-001-5 changed the WECC variance, and not the continent-wide requirements. VAR-001-5 became effective January 1, 2019.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Violation Risk Factor and Violation Severity Level Justifications

Project 2018-03 Standards Efficiency Review Retirements

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 proposed Reliability Standard FAC-008-4. 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 FAC-008-4, Requirement R1

The VRF did not change from the previously FERC approved FAC-008-3 Reliability Standard.

VRF Justification for FAC-008-4, Requirement R2

The VRF did not change from the previously FERC approved FAC-008-3 Reliability Standard.

VRF Justification for FAC-008-4, Requirement R3

The VRF did not change from the previously FERC approved FAC-008-3 Reliability Standard.

VRF Justification for FAC-008-4, Requirement R6

The VRF did not change from the previously FERC approved FAC-008-3 Reliability Standard.

VSL Justification for FAC-008-4, Requirement R1

The VSL did not change from the previously FERC approved FAC-008-3 Reliability Standard.

VSL Justification for FAC-008-4, Requirement R2

The VSL did not change from the previously FERC approved FAC-008-3 Reliability Standard.

VSL Justification for FAC-008-4, Requirement R3

The VSL did not change from the previously FERC approved FAC-008-3 Reliability Standard.

VSL Justification for FAC-008-4, Requirement R6

The VSL did not change from the previously FERC approved FAC-008-3 Reliability Standard.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2018-03 Standards Efficiency Review Retirements

Applicable Standard(s)

- FAC-008-4 – Facility Ratings
- INT-006-5 – Evaluation of Interchange Transactions
- INT-009-3 – Implementation of Interchange
- IRO-002-6 – Reliability Coordination – Monitoring and Analysis
- PRC-004-6 – Protection System Misoperation Identification and Correction
- TOP-001-5 – Transmission Operations
- VAR-001-6 – Voltage and Reactive Control

Requested Retirement(s)

- FAC-008-3 – Facility Ratings
- FAC-013-2 – Assessment of Transfer Capability for the Near-term Transmission Planning Horizon
- INT-004-3.1 – Dynamic Transfers
- INT-006-4 – Evaluation of Interchange Transactions
- INT-009-2.1 – Implementation of Interchange
- INT-010-2.1 – Interchange Initiation and Modification for Reliability
- IRO-002-5 – Reliability Coordination – Monitoring and Analysis
- MOD-001-1a – Available Transmission System Capability
- MOD-004-1 – Capacity Benefit Margin
- MOD-008-1 – Transmission Readability Margin Calculation Methodology
- MOD-020-0 – Providing Interruptible Demands and Direct Control Load Management Data to System Operators and Reliability Coordinators
- MOD-028-2 – Area Interchange Methodology
- MOD-029-2a – Rated System Path Methodology
- MOD-030-3 – Flowgate Methodology
- PRC-004-5(i) – Protection System Misoperation Identification and Correction
- TOP-001-4– Transmission Operations
- VAR-001-5– Voltage and Reactive Control

Requested Withdrawal

- MOD-001-2 – Available Transmission System Capability

Applicable Entities

See subject standards.

Background

In 2017, NERC initiated the Standards Efficiency Review. The scope of this project was to use a risk-based approach to identify potential efficiencies through retirement or modification of Reliability Standard requirements. Following the completion of the first phase of work, the Standards Efficiency Review Team submitted a Standard Authorization Request (SAR) to the NERC Standards Committee in August 2018.

Project 2018-03 Standards Efficiency Review Retirements was initiated to consider and implement the recommendations for Reliability Standard retirements contained in the SAR. This project proposes to:

- retire several Reliability Standards on the grounds that the requirements contained therein are duplicative to other requirements, administrative in nature, or are otherwise unnecessary for reliability;
- revise several currently-effective Reliability Standards to remove duplicative, administrative, or otherwise unnecessary requirements (thereby retiring those requirements); and
- withdraw a standard, MOD-001-2, that is currently pending approval by applicable governmental authorities.

General Considerations

For Reliability Standards that are proposed to be retired in their entirety (i.e., no new standard version is proposed), this Implementation Plan provides that the retirement shall become effective immediately upon regulatory approval.

For Reliability Standards that are revised to remove requirements, the revised standards will become effective on the first day of the first calendar quarter that is three (3) months after applicable regulatory approval. This implementation timeframe reflects consideration that entities may need time to update their internal systems and documentation to reflect the new standard version numbers.

Effective Date

Reliability Standards FAC-008-4, INT-006-5, INT-009-3, IRO-002-6, PRC-004-6, TOP-001-5, and VAR-001-6

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.

Retirement Date

Reliability Standards FAC-008-3, INT-006-4, INT-009-2.1, IRO-002-5, PRC-004-5(i), TOP-001-4, and VAR-001-5

The Reliability Standard shall be retired immediately prior to the effective date of the revised standard in the particular jurisdiction in which the revised standard is becoming effective.

Reliability Standards FAC-013-2, INT-004-3.1, INT-010-2.1, MOD-001-1a, MOD-004-1, MOD-008-1, MOD-020-0, MOD-028-2, MOD-029-2a, and MOD-030-3

The Reliability Standard shall be retired on the effective date of the applicable governmental authority's order approving retirement of 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 be retired on the date the standard is retired by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

PRC-024-3 is posted for a 45-day formal comment period with initial ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	December 2018
SAR posted for comment	December 19, 2018 – January 19, 2019
Standards Committee accepted the revised SAR	February 20, 2019

Anticipated Actions	Date
45-day formal or informal comment period with ballot	April – June 2019
45-day formal or informal comment period with additional ballot	July – August 2019
10-day final ballot	October 2019
Board adoption	November 2019

A. Introduction

1. **Title:** Generator Frequency and Voltage Protection Protective Relay Settings

2. **Number:** PRC-024-3PRC-024-2

3. **Purpose:** Ensure Generator Owners To- set their generator protection, protective relays such that generating resource(s) units remain connected, continuing to support the BES during defined frequency and voltage excursions.

4. **Applicability:**

   4.1. Generator OwnerFunctional Entities:

   4.1.1. Generator Owners that apply protection listed in Section 4.2.1.

   4.1.2. Transmission Owners that own a BES generator step-up (GSU) transformer or collector transformer and apply protection listed in Section 4.2.1.

   4.2. Facilities:

   4.2.1 Frequency, voltage or volts per hertz protection, including frequency or voltage protective functions within control systems that provide tripping or momentary cessation signals to all or part of the generating resource, applied to the following:

   4.2.1.1 Bulk Electric System (BES) generating resource(s).

   4.2.1.2 BES GSU transformer(s).

   4.2.1.3 High side of the generator-connected unit auxiliary transformer installed on BES generating resource(s).

   4.2.1.4 Individual dispersed power producing resources identified in the BES Definition, Inclusion I4.

   4.2.1.5 Elements utilized in aggregation of the dispersed power producing resources.

   4.2.1.6 Collector transformer of resources identified in the BES Definition, Inclusion I4.

5. **Effective Date:** See Implementation Plan for PRC-024-2 PRC-024-3

B. Requirements and Measures

R1. Each Generator Owner or Transmission Owner ~~that has generator frequency protective relaying[1] activated to trip its applicable generating unit(s)~~ shall set its applicable frequency protection ~~protective relaying~~ such that the ~~the generator frequency protective relaying~~generating resource does not trip or enter momentary cessation ~~the applicable generating unit(s)~~ within the "no trip zone" of PRC-024 Attachment 1, subject to the following exceptions~~s~~[2]: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- ~~Generating unit(s) may trip if the protective functions (such as out-of-step functions or loss-of-field functions) operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.~~
- ~~Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).~~
- Generating resource(s) ~~unit(s)~~ may be set to trip or enter momentary cessation within a portion of the "no trip zone" of PRC-024 Attachment 1 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

M1. Each Generator Owner or Transmission Owner shall have evidence that the applicable frequency protection has ~~generator frequency protective relays have~~ been set in accordance with Requirement R1, such as dated setting sheets, calibration sheets, calculations, or other documentation.

R2. Each Generator Owner or Transmission Owner ~~that has generator voltage protective relaying[1] activated to trip its applicable generating unit(s)~~ shall set its ~~protective relaying~~applicable voltage protection such that the ~~generator voltage protective relaying~~generating resource does not trip or enter momentary cessation within the "no trip zone" of PRC-024 Attachment 2~~the applicable generating unit(s) as a result of a~~ during a- voltage excursion at the high side of the GSU or collector transformer, subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]* ~~(at the point of interconnection[3]) caused by an event on the~~

~~[1] Each Generator Owner is not required to have frequency or voltage protective relaying (including but not limited to frequency and voltage protective functions for discrete relays, volts per hertz relays evaluated at nominal frequency, multi-function protective devices or protective functions within control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs) installed or activated on its unit.~~

~~[2] For frequency protective relays associated with dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies to frequency protective relays applied on the individual generating unit of the dispersed power producing resources, as well as frequency protective relays applied on equipment from the individual generating unit of the dispersed power producing resource up to the point of interconnection.~~

~~transmission system external to the generating plant that remains within the "no trip zone" of PRC-024 Attachment 2.[4]~~

- If the Transmission Planner allows less stringent voltage ~~relay~~ protection settings than those required to meet PRC-024 Attachment 2, then the Generator Owner or Transmission Owner may ~~shall~~ set its protection ~~protective relaying~~ within the voltage recovery characteristics of a location-specific Transmission Planner's study. ~~Requirement R2 is subject to the following exceptions: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]~~

- ~~Generating unit(s) may trip in accordance with a Special Protection System (SPS) or Remedial Action Scheme (RAS).~~

- ~~Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).~~

- ~~Generating unit(s) may trip by action of protective functions (such as out-of-step functions or loss-of-field functions) that operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.~~

- Generating resource(s) ~~unit(s)~~ may trip or enter momentary cessation within a portion of the "no trip zone" of PRC-024 Attachment 2 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

M2. Each Generator Owner or Transmission Owner shall have evidence that applicable ~~generator~~ voltage protection has~~protective relays have~~ been set in accordance with Requirement R2, such as dated setting sheets, voltage-time boundaries, calibration sheets, coordination plots, dynamic simulation studies, calculations, or other documentation.

R3. Each Generator Owner or Transmission Owner shall document each known regulatory or equipment limitation[5] that prevents an applicable generating resource(s)~~unit~~ with generator frequency or voltage ~~protective relays~~protection from meeting the ~~relay~~ protection setting criteria in Requirements R1 or R2, including (but not limited to)

~~[3] For the purposes of this standard, point of interconnection means the transmission (high voltage) side of the generator step-up or collector transformer.~~

~~[4] For voltage protective relays associated with dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies to voltage protective relays applied on the individual generating unit of the dispersed power producing resources, as well as voltage protective relays applied on equipment from the individual generating unit of the dispersed power producing resource up to the point of interconnection.~~

[5] Excludes limitations that are caused by the setting capability of the generator frequency and voltage protection ~~protective relays themselves~~ itself but does not exclude limitations originating in the equipment that ~~they~~ it protects.

study results, experience from an actual event, or manufacturer's advice. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. The Generator Owner or Transmission Owner shall communicate the documented regulatory or equipment limitation, or the removal of a previously documented regulatory or equipment limitation, to its Planning Coordinator and Transmission Planner within 30 calendar days of any of the following:

- Identification of a regulatory or equipment limitation.
- Repair of the equipment causing the limitation that removes the limitation.
- Replacement of the equipment causing the limitation with equipment that removes the limitation.
- Creation or adjustment of an equipment limitation caused by consumption of the cumulative turbine life-time frequency excursion allowance.

M3. Each Generator Owner or Transmission Owner shall have evidence that it has documented and communicated any known regulatory or equipment limitations ~~(excluding limitations noted in footnote 3)~~ that resulted in an exception to Requirements R1 or R2 in accordance with Requirement R3, such as a dated email or letter that contains such documentation as study results, experience from an actual event, or manufacturer's advice.

R4. Each Generator Owner or Transmission Owner shall provide its applicable generator protection ~~trip~~ settings associated with Requirements R1 and R2 to the Planning Coordinator or Transmission Planner that models the associated generating resource(s) ~~unit~~ within 60 calendar days of receipt of a written request for the data and within 60 calendar days of any change to those previously requested ~~trip~~ settings unless directed by the requesting Planning Coordinator or Transmission Planner that the reporting of ~~relay~~ protection setting changes is not required. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M4. Each Generator Owner or Transmission Owner shall have evidence that it communicated applicable generator ~~protective relay trip~~ protection settings in accordance with Requirement R4, such as dated e-mails, correspondence or other evidence and copies of any requests it has received for that information.

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 Generator Owner or Transmission Owner shall keep data or evidence of Requirements R1 through R4 for 3 years or until the next audit, whichever is longer.
- If a Generator Owner or Transmission Owner is found non-compliant, the Generator Owner or Transmission Owner shall keep information related to the non-compliance until mitigation is complete and approved for the time period specified above, whichever is longer.

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

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The Generator Owner or Transmission Owner ~~that has frequency protection activated to trip a generating unit,~~ failed to set its applicable ~~generator~~ frequency protection ~~protective relaying~~ so that it does not trip or enter momentary cessation ~~within the criteria listed in~~according to Requirement R1. ~~unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.~~
R2.	N/A	N/A	N/A	The Generator Owner or Transmission Owner ~~with voltage protective relaying activated to trip a generating unit,~~ failed to set its applicable voltage protection ~~protective relaying~~ so that it does not trip or enter momentary cessation ~~as a result of a voltage excursion~~

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				~~at the point of interconnection, caused by an event external to the plant per the criteria specified in~~according to Requirement R2.~~ unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.~~
R3.	The Generator Owner or Transmission Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its Planning Coordinator and Transmission Planner more than 30 calendar days but less than or equal to 60 calendar days of identifying the limitation.	The Generator Owner or Transmission Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its Planning Coordinator and Transmission Planner more than 60 calendar days but less than or equal to 90 calendar days of identifying the limitation.	The Generator Owner or Transmission Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its Planning Coordinator and Transmission Planner more than 90 calendar days but less than or equal to 120 calendar days of identifying the limitation.	The Generator Owner or Transmission Owner failed to document any known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2. OR The Generator Owner or Transmission Owner failed to communicate the documented limitation to its Planning Coordinator and

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Transmission Planner within 120 calendar days of identifying the limitation.
R4.	The Generator Owner or Transmission Owner provided its generator protection settings more than 60 calendar days but less than or equal to 90 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner provided generator protection settings more than 60 calendar days but less than or equal to 90 calendar days of a written request.	The Generator Owner or Transmission Owner provided its generator protection settings more than 90 calendar days but less than or equal to 120 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner provided generator protection settings more than 90 calendar days but less than or equal to 120 calendar days of a written request.	The Generator Owner or Transmission Owner provided its generator protection settings more than 120 calendar days but less than or equal to 150 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner provided generator protection settings more than 120 calendar days but less than or equal to 150 calendar days of a written request.	The Generator Owner failed to provide its generator protection settings within 150 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner Transmission Owner failed to provide generator protection settings within 150 calendar days of a written request.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL

D. Regional Variances

D.A. Variance for the Quebec Interconnection

This Interconnection-wide Variance shall be applicable in the Quebec Interconnection and replaces~~,~~ in its entirety, continent-wide Requirement R2 with the following:

D.A.2. Each Generator Owner or Transmission Owner shall set its applicable voltage protection such that the generating resource does not trip or enter momentary cessation within the "no trip zone" of PRC-024 Attachment 2a during a voltage excursion at the high side of the GSU or collector transformer, subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- If the Transmission Planner allows less stringent voltage protection settings than those required to meet PRC-024 Attachment 2a, then the Generator Owner or Transmission Owner may set its protection~~-~~ within the voltage recovery characteristics of a location-specific Transmission Planner's study.
- Generating resource(s) may trip or enter momentary cessation within a portion of the "no trip zone" of PRC-024 Attachment 2a for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.
- Inverter-based resources voltage protection settings may be set to enter momentary cessation within the "no trip zone" of PRC-024 Attachment 2a during a voltage excursion at the high side of the MPT under the following conditions:
  - After a minimum delay of 0.022 s, when the positive-sequence voltage exceeds 1.25 per unit (p.u.) Normal operation must resume once the voltage drops back below 1.25 p.u.
  - After a minimum delay of 0.022 s, when the phase-to-ground RMS voltages exceeds 1.4p.u., as measured at generator terminals, on one or multiple phases. Normal operation must resume once the voltage drops back below the 1.25 p.u.

M.D.A.2. Each Generator Owner or Transmission Owner shall have evidence that applicable voltage protection has been set in accordance with Requirement R2 such as dated setting sheets, voltage-time boundaries, calibration sheets, coordination plots, dynamic simulation studies, calculations, or other documentation.

~~D.~~E. Associated Documents

Implementation Plan

Industry Recommendation I – Loss of Solar Resources during Transmission Disturbances Due to Inverter Settings

Industry Recommendation II – Loss of Solar Resources during Transmission Disturbances due to Inverter Settings

Blue Cut Fire Disturbance

Canyon 2 Fire Disturbance

"Protective Relaying For Power Generation Systems", Boca Raton, FL, Taylor & Francis, 2006, Reimert, Donald

"IEEE C37.102 IEEE Guide for AC Generator Protection"

"IEEE C50.13 IEEE Standard for Cylindrical-Rotor 50 Hz and 60 Hz Synchronous Generators Rated 10 MVA and Above"

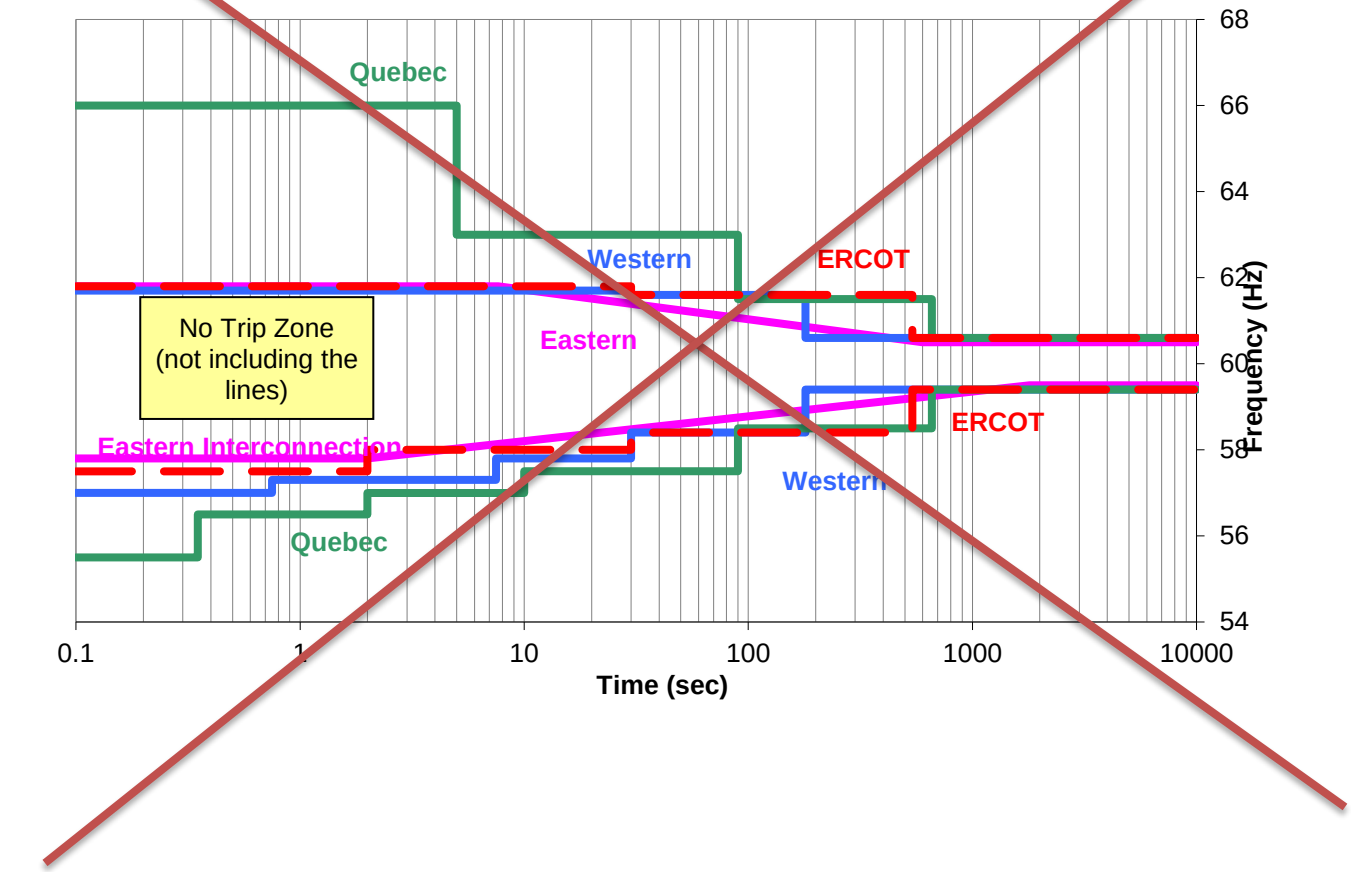
"IEEE C37.106 IEEE Guide for Abnormal Frequency Protection for Power Generating Plants"

Version History

Version	Date	Action	Change Tracking
1	May 9, 2013	Adopted by the NERC Board of Trustees	
1	March 20, 2014	FERC Order issued approving PRC-024-1. (Order becomes effective on 7/1/16.)	
2	February 12, 2015	Adopted by the NERC Board of Trustees	Standard revised in Project 2014-01: Applicability revised to clarify application of requirements to BES dispersed power producing resources
2	May 29, 2015	FERC Letter Order in Docket No. RD15-3-000 approving PRC-024-2	Modifications to adjust the applicability to owners of dispersed generation resources.

PRC-024 — Attachment 1

~~OFF NOMINAL FREQUENCY CAPABILITY CURVE~~



Attachment 1

~~OFF NOMINAL FREQUENCY CAPABILITY CURVE~~

(Frequency No Trip Boundary by Interconnection)

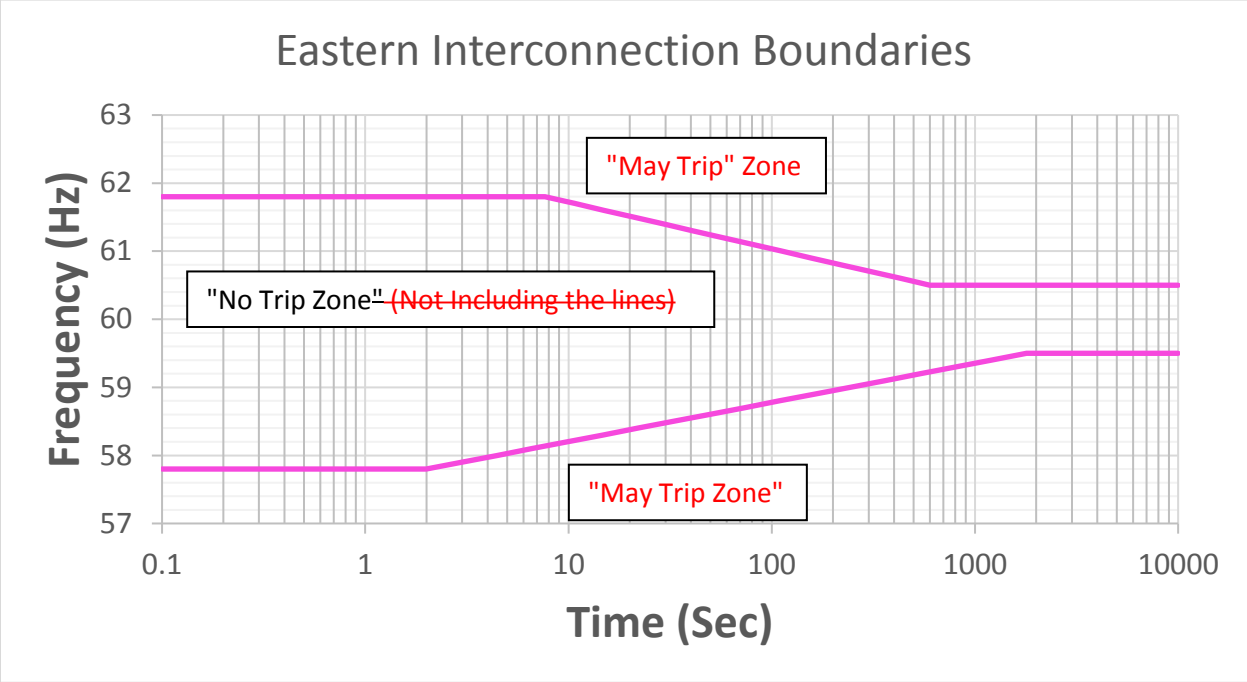


Figure 1

~~Curve~~ Frequency Boundary Data Points – Eastern Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Minimum Time (Sec)	Frequency (Hz)	Minimum Time (sec)
≥61.8	0.10~~Instantaneous trip~~	≤57.8	0.10~~Instantaneous trip~~
≥60.5	$10^{(90.935-1.45713*f)}$	≤59.5	$10^{(1.7373*f-100.116)}$
<60.5	Continuous operation	> 59.5	Continuous operation

Table 1

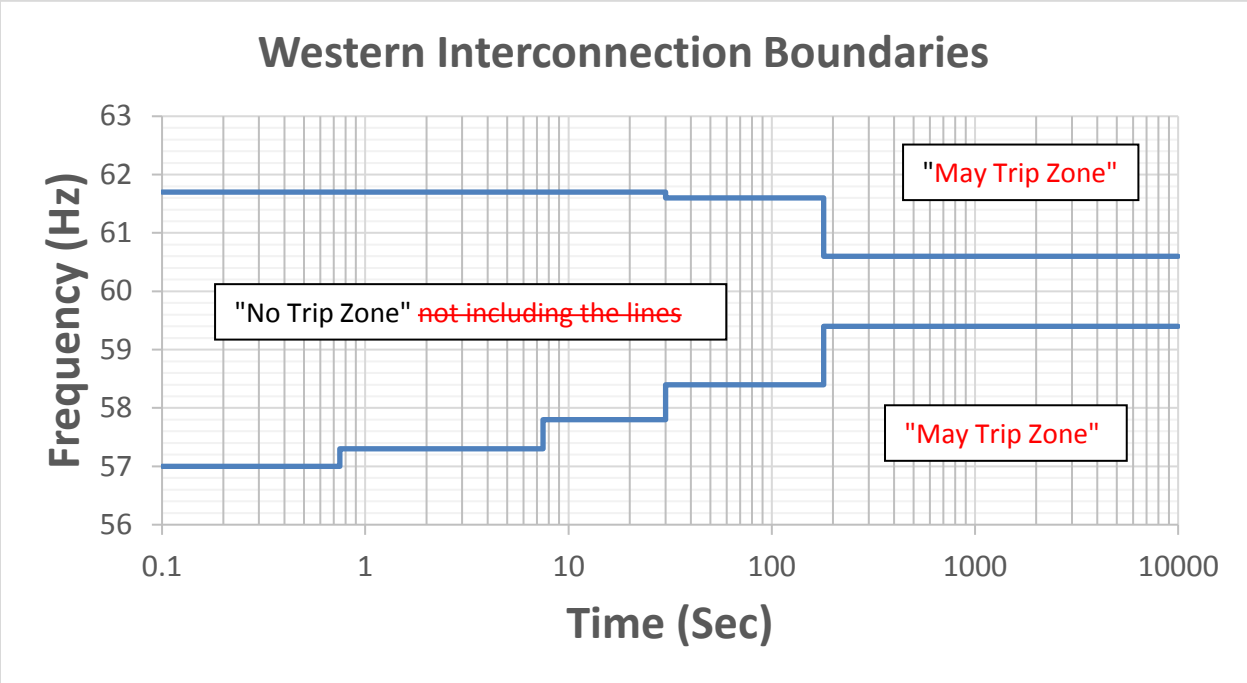


Figure 2

~~Curve~~Frequency- Boundary Data Points – Western Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Minimum Time (Sec)	Frequency (Hz)	Minimum Time (sec)
≥61.7	0.10~~Instantaneous trip~~	≤57.0	0.10~~Instantaneous trip~~
≥61.6	30	≤57.3	0.75
≥60.6	180	≤57.8	7.5
<60.6	Continuous operation	≤58.4	30
		≤59.4	180
		>59.4	Continuous operation

Table 3

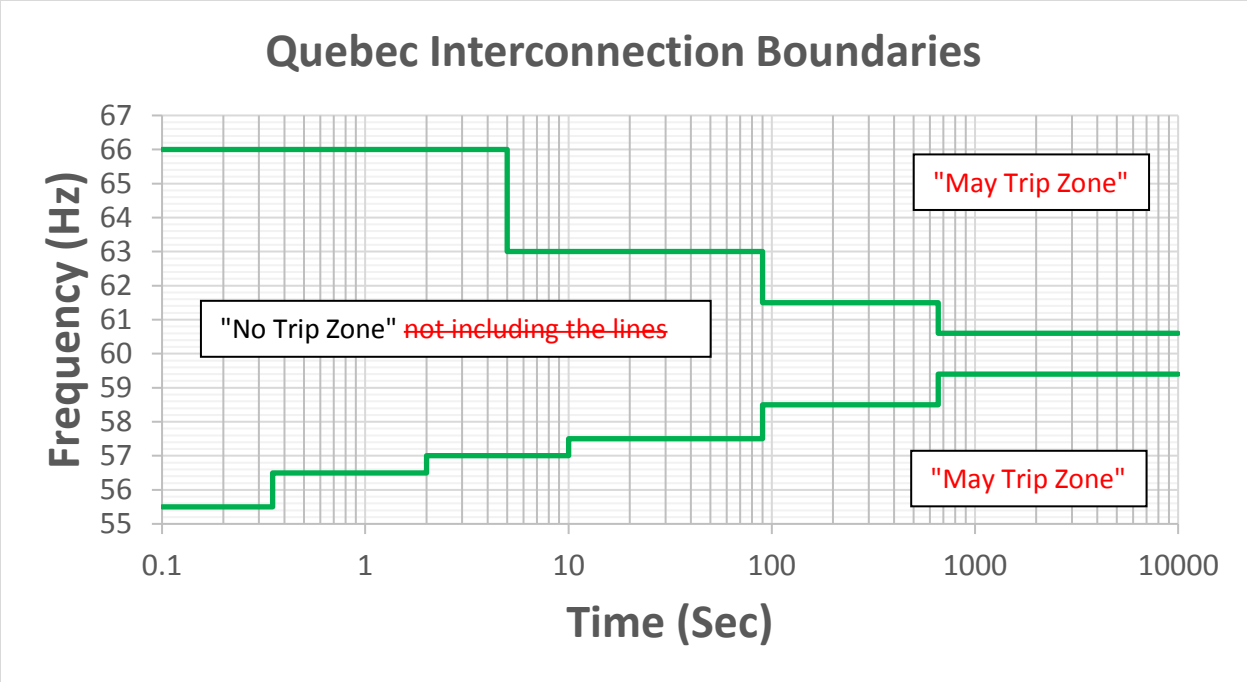


Figure 4

~~Curve~~ Frequency Boundary Data Points – Quebec Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Minimum Time (Sec)	Frequency (Hz)	Minimum Time (Sec)
>66.0	0.10~~Instantaneous trip~~	<55.5	0.10~~Instantaneous trip~~
≥63.0	5	≤56.5	0.35
≥61.5	90	≤57.0	2
≥60.6	660	≤57.5	10
<60.6	Continuous operation	≤58.5	90
		≤59.4	660
		>59.4	Continuous operation

Table 2

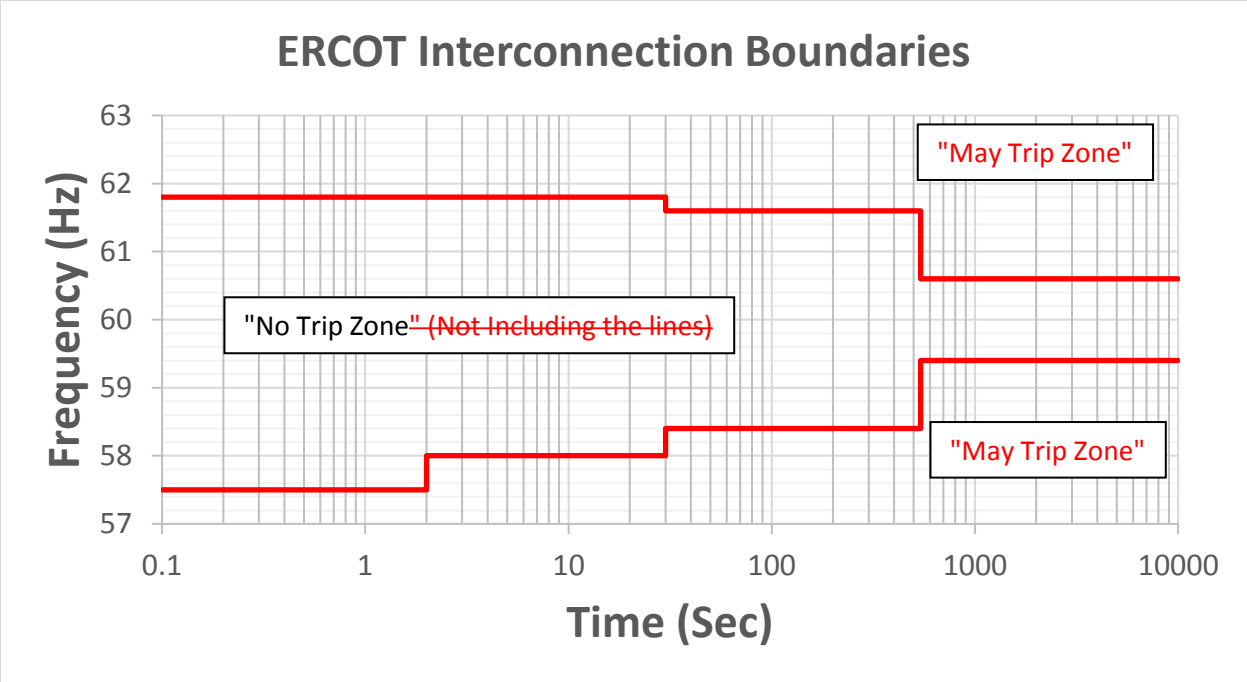


Figure 5

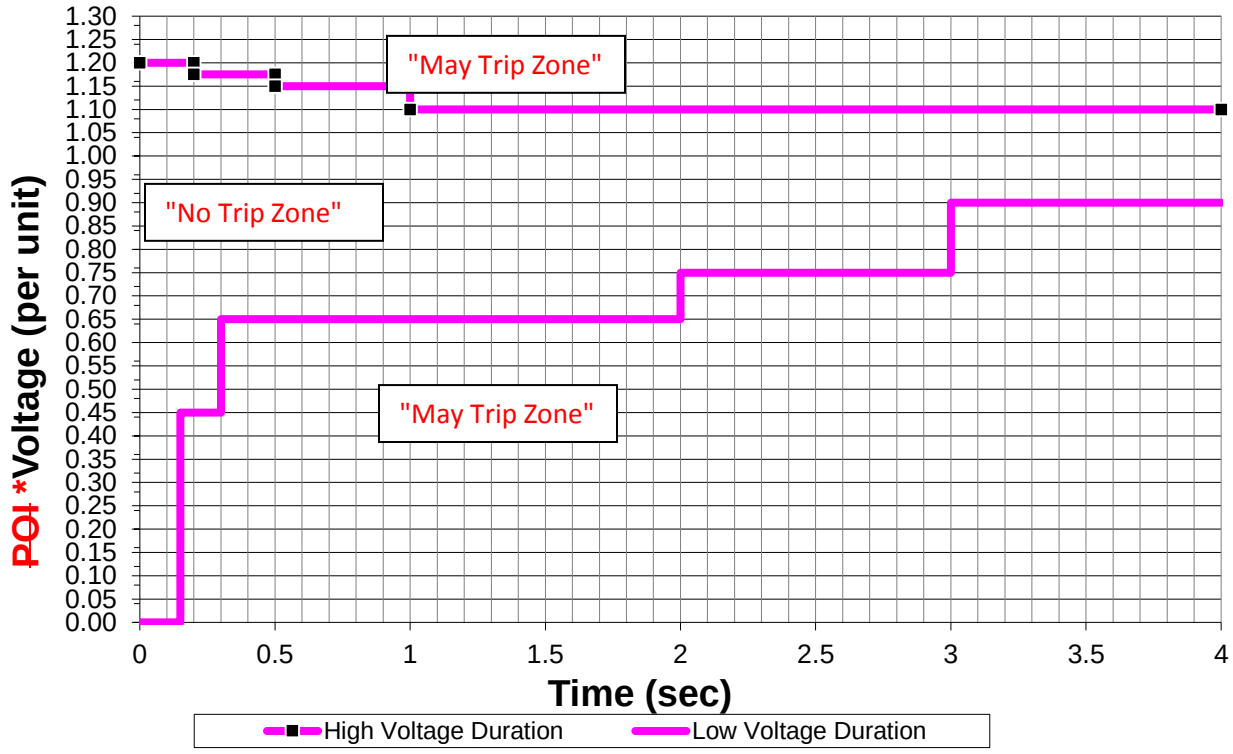
~~Curve~~ Frequency ~~-~~Boundary Data Points ~~–~~ ERCOT Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Minimum Time (Sec)	Frequency (Hz)	Minimum Time (sec)
≥61.8	0.10~~Instantaneous trip~~	≤57.5	0.10~~Instantaneous trip~~
≥61.6	30	≤58.0	2
≥60.6	540	≤58.4	30
<60.6	Continuous operation	≤59.4	540
		>59.4	Continuous operation

Table 3

PRC-024— Attachment 2

(Voltage No-Trip Boundary – Eastern, Western, and ERCOT Interconnections)



6

Figure 1

Voltage Boundary Data Points ~~Ride-Through Duration:~~

High Voltage ~~Ride-Through~~ Duration		Low Voltage ~~Ride-Through~~ Duration	
Voltage (pu)	Minimum Time (sec)	Voltage (pu)	Minimum Time (sec)
≥1.200	~~Instantaneous trip~~0.00	<0.45	0.15
≥1.175	0.20	<0.65	0.30
≥1.15	0.50	<0.75	2.00
≥1.10	1.00	<0.90	3.00

*Voltage at the high-side of the GSU or collector transformer.

<1.10	4.00	≥ 0.90	4.00

Table 1
Voltage at the high-side of the GSU or collector transformer.

Voltage Boundary Clarifications – Eastern, Western, and ERCOT Interconnections

Boundary Details:

1. The per unit voltage base for these boundaries~~curves~~ is the nominal operating voltage (e.g., 115 kV, 138 kV, 230 kV, 345 kV, 500 kV, etc.). ~~specified by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission Systems at the point of interconnection to the Bulk Electric System (BES).~~
2. ~~The curves depicted were derived based on three-phase transmission system zone 1 faults with Normal Clearing not exceeding 9 cycles.~~ The boundaries apply to voltage excursions regardless of the type of initiating event.
3. The values in the table represent the minimum time durations allowed for specified voltage excursion thresholds.~~envelope within the curves represents the cumulative voltage duration at the point of interconnection with the BES. For example, if the voltage first exceeds 1.15 pu at 0.3 seconds after a fault, does not exceed 1.2 pu voltage, and returns below 1.15 pu at 0.4 seconds, then the cumulative time the voltage is above 1.15 pu voltage is 0.1 seconds and is within the no trip zone of the curve.~~
4. The boundaries ~~curves depicted~~ assume a system frequency ~~is~~ of 60 Hertz.~~–~~ When evaluating volts per hertz~~Volts/Hertz~~ protection, ~~you may adjust the~~ magnitude of the high voltage ~~curve~~ boundary can be adjusted in proportion to deviations of frequency below 60 Hertz.
5. Voltages in the ~~curve~~ boundaries assume RMS ~~minimum~~ fundamental frequency phase-to-ground or phase-to-phase voltage. ~~for the low voltage duration curve and the greater of maximum RMS or crest phase-to-phase voltage for the high voltage duration curve~~
6. ~~5.~~ The "no trip zone" ends at 4 seconds.

Evaluating Protection~~Protective Relay~~ Settings:

1. Use either the following assumptions or loading conditions that are believed to be the most probable for the unit under study to evaluate voltage protection ~~relay~~ setting calculations on the static case for steady state initial conditions:
    a. All of the units connected to the same transformer are online and operating.
    b. All of the units are at full nameplate real-power output.
    c. Power factor is 0.95 lagging (i.e. supplying reactive power to the system) as measured at the generator terminals.
    d. The automatic voltage regulator is in automatic voltage control mode.
2. ~~—~~Evaluate voltage protection ~~relay~~ settings assuming that additional installed generating plant reactive support equipment (such as static VAr compensators, synchronous condensers, or capacitors) is available and operating normally.
3. ~~—~~Evaluate voltage protection ~~relay~~ settings accounting for the actual tap settings of transformers between the generator terminals and the ~~point of interconnection~~ high

side of the GSU or collection transformer.

PRC-024— Attachment 2a
(Voltage No Trip Boundaries – Quebec Interconnection)

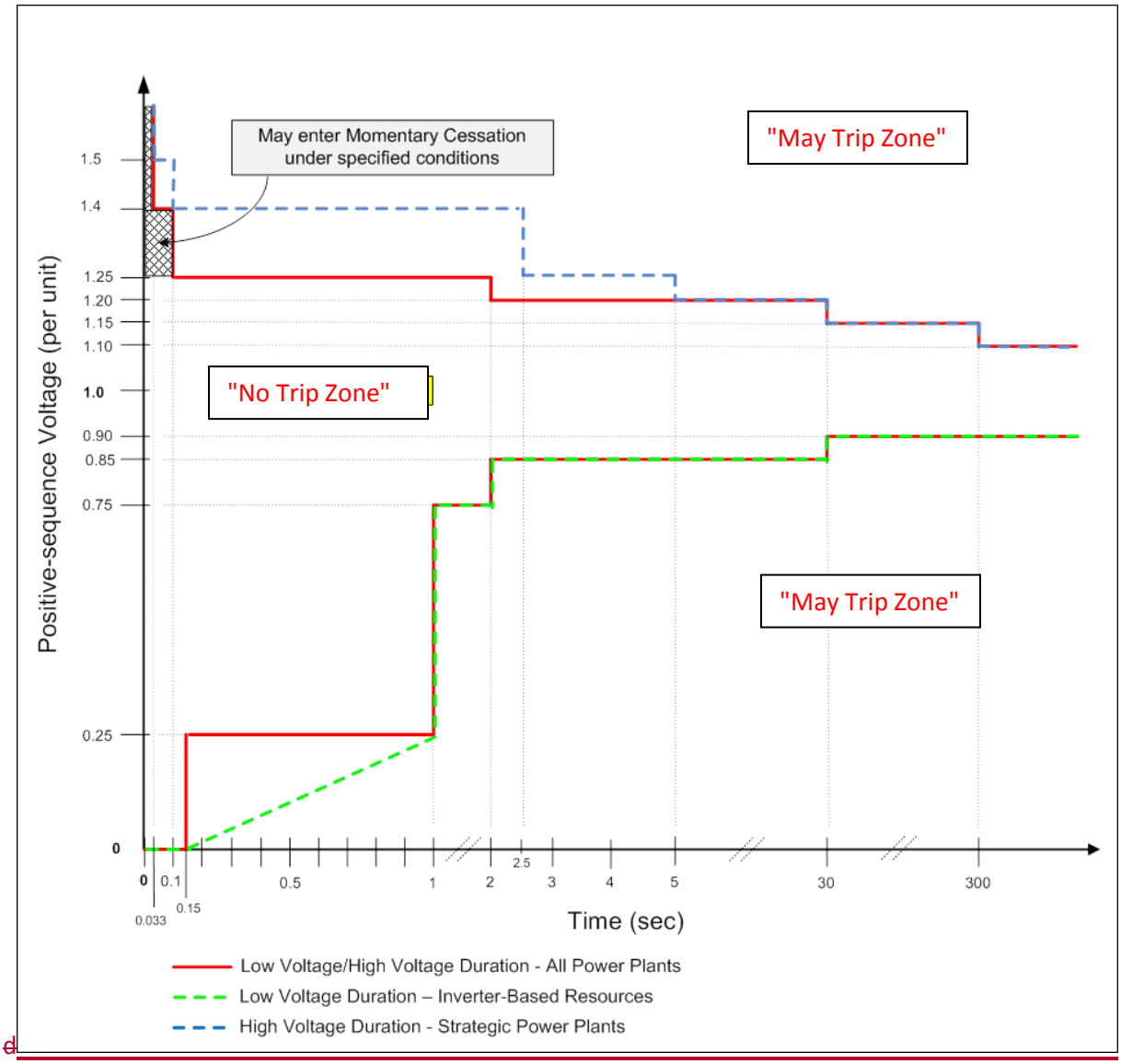


Figure 1a

Voltage Boundary Data Points – Quebec Interconnection

High Voltage Duration for all Power Plants		High Voltage Duration for strategic[2] Power Plants	
Voltage (pu)	Minimum Time (sec)	Voltage (pu)	Minimum Time (sec)
---	---	>1.50	0.033
>1.40	0.033	>1.40	0.10
>1.25	0.10	>1.25	2.50
>1.20	2.00	>1.20	5.00
>1.15	30	>1.15	30
>1.10	300	>1.10	300
≤1.10	continuous	≤1.10	continuous

Table 1a

Voltage Boundary Data Points – Quebec Interconnection

Low Voltage Duration for all Power Plants		Low Voltage Duration for Inverter-Based Resources	
Voltage (pu)	Minimum Time (sec)	Voltage (pu)	Minimum Time (sec)
<0.25	0.15	<0.25	3.4*V(pu)+0.15
<0.75	1.00	<0.75	1.00
<0.85	2.00	<0.85	2.00
<0.90	30	<0.90	30
≥0.90	continuous	≥0.90	continuous

Table 2a

[1] Power Plants designated by the Transmission Planner for protecting the integrity of Transmission System equipment.

Voltage Boundary Clarifications – Quebec Interconnection

Boundary Details:

1. The per unit voltage base for these boundaries is the nominal operating voltage (e.g., 115 kV, 138 kV, 230 kV, 345 kV, 500 kV, etc.).
2. The boundaries apply to voltage excursions regardless of the type of initiating event.
3. The values in the table represent the minimum time durations allowed for specified voltage excursion thresholds.
4. The boundaries assume a system frequency of 60 Hertz. When evaluating volts per hertz protection, magnitude of the high voltage boundary can be adjusted in proportion to deviations of frequency below 60 Hertz.
5. Voltages in the boundaries assume positive-sequence values.

Evaluating Protection Settings:

1. Use either the following assumptions or loading conditions that are believed to be the most probable for the unit under study to evaluate voltage protection setting calculations on the static case for steady state initial conditions:
    a. All of the units connected to the same transformer are online and operating.
    b. All of the units are at full nameplate real-power output.
    c. Power factor is 0.95 lagging (i.e. supplying reactive power to the system) as measured at the generator terminals.
    d. The automatic voltage regulator is in automatic voltage control mode.
2. Evaluate voltage protection settings assuming that additional installed generating plant reactive support equipment (such as static VAr compensators, synchronous condensers, or capacitors) is available and operating normally.
3. Evaluate voltage protection settings accounting for the actual tap settings of transformers between the generator terminals and the high side of the GSU or collector transformer.

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PRC-024-3 – Summary of Key Changes

Project 2018-04 Modifications to PRC-024-2

Momentary Cessation

- Requirements R1 and R2 modified to specify that a generating resource may neither trip NOR enter momentary cessation inside the No Trip Zone

No Trip Zone

- To clarify confusion regarding tripping or entering momentary cessation *outside* the No Trip Zone, the area outside the boundary is now labeled as a "May Trip Zone"

Applicability Section

- Facilities Section added that explicitly lists protective functions for specific equipment
  - Plant Auxiliary Equipment is not included as an applicable facility
  - Specifies that voltage and frequency protection should be applied to both generator step-up (GSU) and collector transformers
  - Addresses a potential reliability gap identified by the standard drafting team
    - Some Transmission Owners (TOs) own GSU or collector transformers, yet are not currently in scope PRC-024

Inclusion of Some TOs as Functional Entities[1]

- *Not all TOs are applicable*
- Only those specific TOs that own a GSU or collector transformer and apply protection listed in the facilities section are now in scope of PRC-024

Point of Interconnection (POI)

- To address ambiguity concerns, removed the term altogether and replaced with precise language for this standard:

[1] Requirements R1 and R2 in the currently enforceable PRC-024-2 standard, via footnotes 2 and 4, include all frequency and voltage protective relays from the individual generating resource to the high side of the main power transformer for dispersed power producing resources. There was also an identified potential reliability gap when frequency and voltage protection, specifically volts per hertz, are applied to conventional generator GSUs. To alleviate this potential reliability gap, and to achieve parity for all resources, the SDT added a facilities section to specify the facilities that are subject to the Standard, if those facilities have frequency and voltage protection enabled. The facilities section now clarifies that the GSU or collector transformer is an applicable facility.

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Implementation Plan

Project 2018-04 Modifications to PRC-024-2
Reliability Standard PRC-024-3

Applicable Standard

- Reliability Standard PRC-024-3 – Generator Frequency and Voltage Protection Settings

Requested Retirement

- Reliability Standard PRC-024-2 – Generator Frequency and Voltage Protective Relay Settings

Prerequisite Standard(s)

- None

Applicable Entities

- Generator Owners that apply protection listed in Section 4.2.1.
- Transmission Owners that own a BES generator step-up transformer or collector transformer and apply protection listed in Section 4.2.1.

Background

On November 27, 2018, the NERC Operating Committee (OC) and Planning Committee (PC) submitted a Standard Authorization Request (SAR) prepared by the Inverter-Based Resource Performance Task Force (IRPTF), which reports to the OC and PC. Project 2018-04 addresses this SAR.

In 2017, the OC and PC convened the IRPTF shortly after it became clear that inverter-based generation was dropping off-line during normally cleared Bulk Power System (BPS) line faults. The NERC IRPTF supported NERC and WECC staff in the analysis of the Blue Cut Fire and Canyon 2 Fire disturbances in southern California. From the key findings and recommendations in the reports on the analysis, the IRPTF (as a stakeholder group of industry experts) developed recommended performance characteristics from inverter-based resources connected to the BPS.

Based off the disturbance analyses and development of the PRC-024-2 Gaps Whitepaper, the IRPTF identified potential modifications to PRC-024-2 to help ensure that inverter-based generator owners, operators, developers, and equipment manufacturers understand the intent of the standard in order for their plants respond to grid disturbances in a manner that contributes to the reliable operation of the BPS.

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Violation Risk Factor and Violation Severity Level Justification

Project 2018-04 Modifications to PRC-024-2 April 2019

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 PRC-024-3. 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.

Justification for PRC-024-3 VRFs and VSLs

VRF Justification for PRC-024-3, Requirement R1

The VRF did not change from the previously FERC-approved PRC-024-2 Reliability Standard.

VSL Justification for PRC-024-3, Requirement R1

The SDT only made changes to conform the Requirement R1 VSL to the revised Requirement R1 language. The SDT retained the binary structure of the VSL, which is consistent with both the PRC-024-2 and PRC-024-1 VSLs. As a result, the justification for the Commission-approved PRC-024-1 Requirement R1 VSL supports the justification for the proposed PRC-024-3, Requirement R1 VSL.

VRF Justification for PRC-024-3, Requirement R2

The VRF did not change from the previously FERC-approved PRC-024-2 Reliability Standard.

VSL Justification for PRC-024-3, Requirement R2

The SDT only made changes to conform the Requirement R2 VSL to the revised Requirement R2 language. The SDT retained the binary structure of the VSL, which is consistent with both the PRC-024-2 and PRC-024-1 VSLs. As a result, the justification for the Commission-approved PRC-024-1 Requirement R2 VSL supports the justification for the proposed PRC-024-3, Requirement R2 VSL.

VRF Justification for PRC-024-3, Requirement R3

The VRF did not change from the previously FERC-approved PRC-024-2 Reliability Standard.

VSL Justification for PRC-024-3, Requirement R3

The SDT only revised the Requirement R3 VSL to add Transmission Owner. The SDT retained the existing levels of the VSLs, which is consistent with both the PRC-024-2 and PRC-024-1 VSLs. As a result, the justification for the Commission-approved PRC-024-1 Requirement R3 VSL supports the justification for the proposed PRC-024-3, Requirement R3 VSL.

VRF Justification for PRC-024-3, Requirement R4

The VRF did not change from the previously FERC-approved PRC-024-2 Reliability Standard.

VSL Justification for PRC-024-3, Requirement R4

The SDT only revised the Requirement R4 VSL to add Transmission Owner. The SDT retained the existing levels of the VSLs, which is consistent with both the PRC-024-2 and PRC-024-1 VSLs. As a result, the justification for the Commission-approved PRC-024-1 Requirement R4 VSL supports the justification for the proposed PRC-024-3, Requirement R4 VSL.

General Considerations

This Implementation Plan includes an effective date as well as phased-in compliance dates. As detailed below, there are two compliance dates: one for Generator Owners and one for Transmission Owners.

Effective Date

Reliability Standard PRC-024-3

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 eighteen (18) 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 eighteen (18) 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 Applicable Generator Owners

Applicable Generator Owners shall comply with all Requirements upon the effective date of Reliability Standard PRC-024-3.

Compliance Date for Applicable Transmission Owners

Applicable Transmission Owners shall not be required to comply with the Requirements until forty-two (42) months after the effective date of Reliability Standard PRC-024-3.

Retirement Date

Reliability Standard PRC-024-2

Reliability Standard PRC-024-2 shall be retired immediately prior to the effective date of Reliability Standard PRC-024-3 in the particular jurisdiction in which the revised standard is becoming effective.

- "at the high side of the GSU or collector transformer"

Figures and Tables

- Clarified areas of confusion as specified by the Standard Authorization Request
- General "clean up" work throughout

Variance – Quebec Interconnection

- Variance to Requirement R2 with more stringent under/over voltage boundaries

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Standard Authorization Request (SAR)

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:	Revisions to TPL-007-3 Transmission System Planned Performance for Geomagnetic Disturbance		
Date Submitted:			
SAR Requester			
Name:	Soo Jin Kim		
Organization:	NERC		
Telephone:	404-446-9742	Email:	Soo.jin.kim@nerc.net
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?):			
On November 15, 2018, the Federal Energy Regulatory Commission (FERC) issued Order No. 851 in order to modify Reliability Standard TPL-007-2.			
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):			
This project will address the directives issued by FERC in Order No. 851 to modify Reliability Standard TPL-007-2. FERC directed NERC to submit modifications to: (1) require the development and implementation of corrective action plans to mitigate assessed supplemental GMD event vulnerabilities (P 29); and (2) to replace the corrective action plan time-extension provision in Requirement R7.4 with a process through which extensions of time are considered on a case-by-case basis (P 54). NERC was directed to submit the modified Reliability Standard for approval within 12 months from the effective date of Reliability Standard TPL-007-2.			

Requested information
Project Scope (Define the parameters of the proposed project):
This project will address the directives issued by FERC in Order No. 851 to modify Reliability Standard TPL-007-3.
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):
The Standard Drafting Team (SDT) will address FERC's directives in Order No. 851 that require the development and completion of corrective actions plans to mitigate assessed supplemental GMD event vulnerabilities. The SDT will also modify the provisions in Reliability Standard TPL-007-3, Requirement R7.4 that allows applicable entities to exceed deadlines for completing corrective action plan tasks when situations beyond the control of the responsible entity arise. The SDT will also need to evaluate the Canadian variance and make any appropriate changes to the variance based on the modifications arising from FERC Order No. 851.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
The potential cost impacts associated with adding corrective action plan requirements for supplemental GMD event vulnerabilities are unknown at this time.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g*. Dispersed Generation Resources):
Not Applicable
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 Owner, Generator Owner
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)?
Project 2018-01 TPL-007-3 (Canadian Variance). EOP-010-1 Geomagnetic Disturbance Operations
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.

[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.

Requested information
Order No. 830 GMD Research Work Plan could help to inform the SDT while making the required modifications to the standard laid out in Order No. 851.

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
TPL-007-3 Canadian Variance	The only difference between TPL-007-3 and TPL-007-2 is that TPL-007-3 adds a Canadian Variance to address regulatory practices/processes within Canadian jurisdictions and to allow the use of Canadian-specific data and research to define and implement alternative GMD event(s) that achieve at least an equivalent reliability objective of the defined benchmark and supplemental GMD events in TPL-007-2 Attachment 1.

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 18, 2017	Standards Information Staff	Revised
2	June 28, 2017	Standards Information Staff	Updated template

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Standard Authorization Request (SAR)

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:	BES Cyber System Information Access Management		
Date Submitted:	March 1, 2019		
SAR Requester			
Name:	Alice Ireland		
Organization:	Tri-State Generation and Transmission Association		
Telephone:	(303) 254-3120	Email:	aireland@tristategt.org
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?):			
While there is no direct benefit to the reliability of the BES, this initiative enhances BES reliability by creating increased choice, greater flexibility, higher availability, and reduced-cost options for entities to manage their BES Cyber System Information, by providing a secure path towards utilitzation of modern third-party data storage and analysis systems. In addition, the proposed project would clarify the protections expected when utilizing third-party solutions (aka cloud).			
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):			
Clarifying the CIP requirements related to BES Cyber System Information access, to allow for alternative methods, such as encryption, to be utilized in the protection of BCSI.			
Project Scope (Define the parameters of the proposed project):			
CIP-004 and CIP-011			

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):
CIP-004-6 Requirement R4 Part 4.1.3 needs to be modified so authorization and access to BCSI is clarified to focus on the BCSI and the controls deployed to limit access. In addition, the Standard should allow multiple methods for controlling access to BES Cyber System Information, rather than just electronic and physical access to the BES Cyber System Information storage location. For example, the focus must be on BCSI and the ability to obtain and make use of it. This is particularly necessary when it comes to the utilization of a third party's system (aka cloud). As currently drafted, the requirement is focused on access to the "storage location", and therefore does not permit methods such as encryption and key management to be utilized in lieu of physical/electronic access controls. This wording also does not explicitly permit any flexibility in the audit approach. In addition to modifying CIP-004-6 Requirement R4 Part 4.1.3, Part 4.4, Part 5.3 and CIP-011-2 Requirement R1 should also be evaluated for any subsequent impacts to the requirements, measures and/or the guidelines and technical basis.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
Potential cost savings due to economies of scale and third party support.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g*. Dispersed Generation Resources):
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):
Please see Section 4. Applicability of CIP-004-6 and CIP-011-2.
Do you know of any iconsensus building activities[2] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus bulding activity.
An informal team, under the direction of the NERC Compliance Input Working Group, was assembled to review the use of encryption on BES Cyber System Information, and the impact on compliance, with a particular focus on such BES Cyber System Information being stored or utilized by a third party's system (aka cloud). This team met every two weeks during Dec. 2018 – Feb. 2019. The development of this SAR was supported by all team members. The team consisted of the following individuals:

[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.

Requested information

Name	Company
Alice Ireland (lead)	Tri-State Generation and Transmission
David Vitkus	Tucson Electric Power
Eric Hull	SMUD
Marina Rohnow	Sempra Utilities/ San Diego Gas & Electric
Paul Haase	Seattle City Light
Richie Field	Hoosier Energy REC, Inc.
Rob Ellis	Tri-State Generation and Transmission
Steve Wesling	Tri-State Generation and Transmission
Toley Clague	Portland General Electric
Ziad Dassouki	ATCO Electric
Joseph Baxter	NERC
Lonnie Ratliff	NERC
Brian Kinstad	MRO
Holly Eddy	WECC
Kenath Carver	Texas Reliability Entity, Inc.
Michael Taube	MRO
Mike Stuetzle	NPCC
Morgan King	WECC
Shon Austin	Reliability First
Tremayne Brown	SERC

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)?

Project 2016-02 Modifications to CIP Standards

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.

When evaluating ways to modify the requirement, other standards and requirements were identified, which provide examples on possible paths forward. Of particular relevance are the following standards/requirements:

- CIP-006-6 Requirement R1 Part 1.10;
- CIP-010-2 Requirement R4, Attachment 1, Section 1.5;
- CIP-012-1 Requirement R1 (pending FERC approval).

Requested information
As a means to assist the SDT, several possible options for revision to CIP-004-6 Requirement R4 Part 4.1.3 have been drafted and provided below: EXAMPLE #1: [Delete 4.1.3 and create a new subrequirement in either CIP-004 or CIP-011, that would read something like this:] R4.X Process to prevent unauthorized access to BES Cyber System Information. The process shall include: 4.X.1. Identification of physical and electronic repositories utilized to store BES Cyber System Information. If electronic, indicate whether the repository is hosted by the Responsible Entity or a third-party and also whether it is in a virtual or non-virtual environment.; 4.X.2. Identification of security protection(s) used to prevent unauthorized access to BES Cyber System Information within each repository. Examples may include but are not limited to the following: • Encryption and key management, • Physical access management, • Electronic access management, • Data loss prevention techniques and rights management services. 4.X.3. The process to authorize access to BES Cyber System Information, based on need, as determined by the Responsible Entity, except for CIP Exceptional Circumstances; EXAMPLE #2: R4.1 Process to authorize based on need, as determined by the Responsible Entity, except for CIP Exceptional Circumstances: 4.1.1. Electronic access; 4.1.2. Unescorted physical access into a Physical Security Perimeter; 4.1.3. Physical access to physical BES Cyber System Information storage locations; 4.1.4. Physical access to unencrypted electronic BES Cyber System Information storage locations; 4.1.5. Electronic access to unencrypted electronic BES Cyber System Information storage locations; and 4.1.6. Electronic access to BES Cyber System Information encryption keys for encrypted BES Cyber System Information. EXAMPLE #3: R4.1 Process to authorize based on need, as determined by the Responsible Entity, except for CIP Exceptional Circumstances: 4.1.1. Electronic access; 4.1.2. Unescorted physical access into a Physical Security Perimeter; 4.1.3. Physical access to physical BES Cyber System Information storage locations; 4.1.4. Access to electronic BES Cyber System Information.

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 18, 2017	Standards Information Staff	Revised
2	June 28, 2017	Standards Information Staff	Updated template

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
1	Project 2007-24	Request for Interpretation - TPL-002 and TPL-003 - Ameren_in	Initial Ballot	4/25/2008	5/7/2008	Quorum: 82.61% Approval: 80.73%			
2	Project 2007-26	Request for Interpretation - TPL-002 and TPL-003 - MISO_in	Initial Ballot	4/25/2008	5/7/2008	Quorum: 83.01% Approval: 79.89%			
3	Project 2008-04	FAC-010_FAC-011_FAC-014_Order_705_in	Initial Ballot	6/2/2008	6/11/2008	Quorum: 88.83% Approval: 95.43%			
4	Project 2008-07	Interpretation Request - EOP-002 - Brookfield_in	Initial Ballot	6/2/2008	6/11/2008	Quorum: 89.67% Approval: 76.47%			
5	Project 2008-04	FAC-010_FAC-011_FAC-014_Order_705_rc	Recirculation Ballot	6/13/2008	6/22/2008	Quorum: 89.36% Approval: 95.21%			
6	Project 2008-09	Request for Interpretation - EOP-001-0 - RECM_in	Initial Ballot	6/19/2008	7/2/2008	Quorum: 84.82% Approval: 85.79%			
7	Project 2007-24	Request for Interpretation - TPL-002 and TPL-003 - Ameren_rc	Recirculation Ballot	6/27/2008	7/7/2008	Quorum: 83.57% Approval: 79.13%			
8	Project 2007-26	Request for Interpretation - TPL-002 and TPL-003 - MISO_rc	Recirculation Ballot	6/27/2008	7/7/2008	Quorum: 83.98% Approval: 78.31%			
9	Pre-2006	IROL Standard - IRO-010_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 92.71% Approval: 88.40%			
10	Pre-2006	IROL Standard - IRO-009_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 92.63% Approval: 89.44%			
11	Pre-2006	IROL Standard - IRO-008_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 92.67% Approval: 91.71%			
12	Project 2006-07	ATC et al Standard - MOD-030_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 94.37% Approval: 56.56%			
13	Project 2006-07	ATC et al Standard - MOD-029_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 94.67% Approval: 92.62%			
14	Project 2006-07	ATC et al Standard - MOD-028_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 94.64% Approval: 79.47%			
15	Project 2006-07	ATC et al Standard - MOD-008_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 94.27% Approval: 80.44%			
16	Project 2006-07	ATC et al Standard - MOD-001_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 94.02% Approval: 75.97%			
17	Project 2008-10	Request for Interpretation - CIP-006-1 - Progress Energy_in	Initial Ballot	8/7/2008	8/16/2008	Quorum: 88.18% Approval: 21.52%			
18	Pre-2006	IROL Standard - IRO-008_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 93.72% Approval: 89.49%			
19	Pre-2006	IROL Standard - IRO-009_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 93.68% Approval: 86.53%			
20	Pre-2006	IROL Standard - IRO-010_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 93.75% Approval: 85.95%			
21	Project 2006-07	ATC et al Standards - MOD-001_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 94.87% Approval: 76.83%			
22	Project 2006-07	ATC et al Standard - MOD-008_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 95.15% Approval: 81.49%			
23	Project 2006-07	ATC et al Standard - MOD-028_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 95.54% Approval: 79.34%			
24	Project 2006-07	ATC et al Standard - MOD-029_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 95.56% Approval: 92.24%			
25	Project 2006-07	ATC et al Standard - MOD-030_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 95.24% Approval: 74.26%			
26	Project 2008-11	Request for Interpretation - VAR-002-1 - ICF Consulting_in	Initial Ballot	9/9/2008	9/17/2008	Quorum: 85.78% Approval: 90.37%			
27	Project 2006-07	ATC et al Standard - MOD-004_in	Initial Ballot	9/11/2008	9/21/2008	Quorum: 79.26% Approval: 66.29%			
28	Project 2007-14	Permanent Changes to CI Timing Tables_in	Initial Ballot	9/12/2008	9/22/2008	Quorum: 79.74% Approval: 100.00%			
29	Project 2008-07	Request for Interpretation - Brookfield Power - EOP-002_rb	Re-ballot	10/6/2008	10/24/2008	Quorum: 82.61% Approval: 74.67%			
30	Project 2008-13	Request for Interpretation - TOP-002-2 - Orlando Utilities Commission_in	Initial Ballot	10/21/2008	10/30/2008	Quorum: 83.33% Approval: 96.94%			
31	Project 2006-01	Project 2006-01 - PER-005-1_in	Initial Ballot	10/27/2008	11/5/2008	Quorum: 90.13% Approval: 82.47%			
32	Project 2006-09	Project 2006-09 - FAC-008-2 - Facility Ratings_in	Initial Ballot	10/27/2008	11/5/2008	Quorum: 89.13% Approval: 70.01%			
33	Project 2006-07	ATC et al Standard - MOD-004_rc	Recirculation Ballot	10/28/2008	11/6/2008	Quorum: 91.49% Approval: 83.71%			
34	Project 2006-07	Project 2006-07 (ATC) MOD-030-2_in	Initial Ballot	12/1/2008	12/10/2008	Quorum: 83.77% Approval: 86.51%			
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%			

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37	Project 2006-01	Project 2006-01 - PER-005-1_rc	Recirculation Ballot	12/12/2008	12/22/2008	Quorum: 91.48% Approval: 80.63%			
38	Project 2008-15	Request for Interpretation - CIP-006-1a - US Army COE_in	Initial Ballot	1/5/2009	1/14/2009	Quorum: 91.15% Approval: 97.39%			
39	Project 2008-16	TOP-004-2 VSL Revisions_in	Initial Ballot	1/5/2009	1/14/2009	Quorum: 91.20% Approval: 93.93%			
40	Project 2008-11	Request for Interpretation - VAR-002-1 - ICF Consulting_rc	Recirculation Ballot	1/6/2009	1/15/2009	Quorum: 91.47% Approval: 91.21%			
41	Project 2006-07	Project 2006-07 (ATC) MOD-030-2_rc	Recirculation Ballot	1/20/2009	1/29/2009	Quorum: 85.86% Approval: 86.39%			
42	Project 2008-16	TOP-004-2 VSL Revisions_rc	Recirculation Ballot	1/28/2009	2/6/2009	Quorum: 92.59% Approval: 96.06%			
43	Project 2008-15	Request for Interpretation - CIP-006-1a - US Army COE_rc	Recirculation Ballot	2/6/2009	2/16/2009	Quorum: 93.81% Approval: 99.12%			
44	Project 2008-09	Interpretation Request - EOP-001 - R1 - RECM_in	Initial Ballot	2/27/2009	3/9/2009	Quorum: 89.67% Approval: 89.03%			
45	Project 2008-18	Project 2008-18 Interpretation-Manitoba Hydro_in	Initial Ballot	3/19/2009	3/30/2009	Quorum: 89.78% Approval: 92.62%			
46	Project 2008-06	Project 2008-06: CIP-002-1-CIP-009-1 Revisions_in	Initial Ballot	4/1/2009	4/10/2009	Quorum: 91.90% Approval: 84.06%			
47	Project 2009-10	Project 2009-10 Interpretation - CMPWG - PRC-005-1 R1_in	Initial Ballot	4/8/2009	4/17/2009	Quorum: 92.70% Approval: 92.71%			
48	Project 2006-03	Project 2006-03 EOP-001_EOP-005_EOP-006 System Restoration and Blackstart_in	Initial Ballot	4/14/2009	4/23/2009	Quorum: 89.81% Approval: 76.63%			
49	Project 2008-06	Project 2008-06: CIP-002-1-CIP-009-1 Revisions_rc	Recirculation Ballot	4/17/2009	4/27/2009	Quorum: 94.37% Approval: 88.32%			
50	Project 2008-18	Project 2008-18 Interpretation-Manitoba Hydro_rc	Recirculation Ballot	4/17/2009	4/27/2009	Quorum: 95.56% Approval: 92.81%			
51	Project 2009-11	Project 2009-11 Interpretation WECC Reliability Coordination Subcommittee IRO-10-1_in	Initial Ballot	4/22/2009	5/1/2009	Quorum: 88.64% Approval: 84.77%			
52	Project 2006-03	Project 2006-03 EOP-001_EOP-005_EOP-006 System Restoration and Blackstart_rc	Recirculation Ballot	5/6/2009	5/18/2009	Quorum: 92.08% Approval: 75.39%			
53	Project 2009-15	Project 2009-15 Interpretation - NYISO - MOD-001-1, MOD-029-1_in	initial Ballot	5/25/2009	6/4/2009	Quorum: 85.13% Approval: 82.10%			
54	Project 2009-11	Project 2009-11 Interpretation WECC Reliability Coordination Subcommittee IRO-10-1_rc	Recirculation Ballot	5/26/2009	6/5/2009	Quorum: 90.45% Approval: 85.76%			
55	Project 2009-14	Project 2009-14 Interpretation - PacifiCorp - TPL-002-0a_in	Initial Ballot	6/1/2009	6/11/2009	Quorum: 87.10% Approval: 95.71%			
56	Project 2009-08	Project 2009-08 - Nuclear Plant Interface Coordination for Order 716_in	Initial Ballot	6/12/2009	6/22/2009	Quorum: 81.72% Approval: 94.09%			
57	Project 2008-14	Project 2008-14 VSLs for CIP-002-1 through CIP-009-1_in	Initial Ballot	6/15/2009	6/24/2009	Quorum: 87.23% Approval: 83.94%			
58	Project 2008-14	Project 2008-14 VSLs for CIP-002-1 through CIP-009-1_rc	Recirculation Ballot	7/7/2009	7/16/2009	Quorum: 92.77% Approval: 84.96%			
59	Project 2009-15	Project 2009-15 Interpretation - NYISO - MOD-001-1, MOD-029-1_rc	Recirculation Ballot	7/8/2009	7/17/2009	Quorum: 90.26% Approval: 82.25%			
60	Project 2009-08	Project 2009-08 - Nuclear Plant Interface Coordination for Order 716_rc	Recirculation Ballot	7/10/2009	7/20/2009	Quorum: 87.10% Approval: 96.94%			
61	Project 2009-10	Project 2009-10 Interpretation - CMPWG - PRC-005-1 R1_rc	Recirculation Ballot	7/24/2009	8/6/2009	Quorum: 95.26% Approval: 95.62%			
62	Project 2009-14	Project 2009-14 Interpretation - PacifiCorp - TPL-002-0a_rc	Recirculation Ballot	7/24/2009	8/6/2009	Quorum: 91.24% Approval: 98.85%			
63	Project 2007-23	Project 2007-23 TPL Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 85.71% Approval: 90.46%			
64	Project 2007-23	Project 2007-23 TOP Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 86.40% Approval: 89.14%			
65	Project 2007-23	Project 2007-23 PRC Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 86.32% Approval: 88.26%			
66	Project 2007-23	Project 2007-23 IRO Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 86.16% Approval: 90.15%			
67	Project 2007-23	Project 2007-23 INT, PER, and NUC Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 85.71% Approval: 88.63%			
68	Project 2007-23	Project 2007-23 FAC and MOD Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 86.64% Approval: 87.63%			
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%			

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
73	RSDP V7	Reliability Standards Development Procedure - Version 7 - June 2009_rb	Re-ballot	7/27/2009	8/14/2009	Quorum: 84.65% Approval: 74.79%			
74	Project 2009-09	Project 2009-09 - Interpretation - Covanta Energy - CIP-001-1_in	Initial Ballot	8/6/2009	8/17/2009	Quorum: 84.68% Approval: 68.92%			
75	Project 2007-23	Project 2007-23 TPL Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 91.96% Approval: 89.28%			
76	Project 2007-23	Project 2007-23 BAL Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 92.04% Approval: 89.41%			
77	Project 2007-23	Project 2007-23 CIP, COM, and VAR Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 92.41% Approval: 84.64%			
78	Project 2007-23	Project 2007-23 FAC and MOD Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 92.67% Approval: 88.04%			
79	Project 2007-23	Project 2007-23 INT, PER, and NUC Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 92.17% Approval: 88.73%			
80	Project 2007-23	Project 2007-23 IRO Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 91.96% Approval: 90.77%			
81	Project 2007-23	Project 2007-23 PRC Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 92.31% Approval: 86.93%			
82	Project 2007-23	Project 2007-23 TOP Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 92.11% Approval: 88.26%			
83	Project 2008-08	Project 2008-08 EOP Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 92.70% Approval: 85.80%			
84	Order 706-B	Order 706-B Nuclear Implementation Plan_in	Initial Ballot	8/19/2009	8/28/2009	Quorum: 81.96% Approval: 97.37%			
85	Project 2008-07	Request for Interpretation - Brookfield Power - EOP-002_rc	Recirculation Ballot	8/20/2009	8/31/2009	Quorum: 86.96% Approval: 70.85%			
86	Project 2009-12	Project 2009-12 - Interpretation - PacifiCorp - CIP-005-1_in	Initial Ballot	8/27/2009	9/8/2009	Quorum: 84.68% Approval: 80.37%			
87	Project 2009-13	Project 2009-13 - Interpretation - PacifiCorp - CIP-006-1_in	Initial Ballot	8/27/2009	9/8/2009	Quorum: 84.92% Approval: 79.04%			
88	Project 2009-18	Project 2009-18 - Withdraw Three Midwest ISO Waivers_in	Initial Ballot	8/27/2009	9/8/2009	Quorum: 85.28% Approval: 99.62%			
89	Order 706-B	Order 706-B Nuclear Implementation Plan_rc	Recirculation Ballot	9/1/2009	9/10/2009	Quorum: 87.11% Approval: 97.18%			
90	RSDP V7	Reliability Standards Development Procedure - Version 7 - June 2009_rc	Recirculation Ballot	9/2/2009	9/14/2009	Quorum: 86.31% Approval: 76.09%			
91	Project 2008-06	Project 2008-06 Cyber Security (VRFs and VSLs for Version 2 CIP Standards)_in	Initial Ballot	9/10/2009	9/21/2009	Quorum: 87.45% Approval: 94.18%			
92	Project 2009-16	Project 2009-16 - Interpretation - WECC - CIP-007-1_in	Initial Ballot	9/9/2009	9/21/2009	Quorum: 85.31% Approval: 100.00%			
93	Project 2006-04	Project 2006-04 - Back-up Facilities - EOP-008-1_in	Initial Ballot	9/16/2009	9/28/2009	Quorum: 82.69% Approval: 72.86%			
94	Project 2009-09	Project 2009-09 - Interpretation - Covanta Energy - CIP-001-1_rc	Recirculation Ballot	9/29/2009	10/9/2009	Quorum: 89.92% Approval: 68.31%			
95	Project 2008-10	Project 2008-10 - Interpretation of CIP-006-1 Revised R1 for Progress Energy	Initial Ballot	9/30/2009	10/12/2009	Quorum: 79.92% Approval: 74.47%			
96	Project 2009-12	Project 2009-12 - Interpretation - PacifiCorp - CIP-005-1_rc	Recirculation Ballot	10/16/2009	10/26/2009	Quorum: 86.29% Approval: 83.25%			
97	Project 2008-06	Project 2008-06 Cyber Security (VRFs and VSLs for Version 2 CIP Standards)_rc	Recirculation Ballot	11/2/2009	11/12/2009	Quorum: 88.70% Approval: 94.24%			
98	Project 2008-09	Project 2008-09 - Interpretation - RECM - Revision 2_in	Initial Ballot	11/5/2009	11/16/2009	Quorum: 85.97% Approval: 98.07%			
99	Project 2009-21	Project 2009-21 - Cyber Security Ninety-day Response_in	Initial Ballot	11/20/2009	11/30/2009	Quorum: 89.58% Approval: 88.07%			
100	Project 2009-17	Project 2009-17 - Interpretation Y-W Electric and Tri-State (Revision 1)_in	Initial Ballot	11/19/2009	12/7/2009	Quorum: 85.83% Approval: 58.91%			
101	Project 2009-20	Project 2009-20 - Interpretation - BAL-003-0 - Energy Mark, Inc._in	Initial Ballot	11/20/2009	12/7/2009	Quorum: 87.11% Approval: 93.40%			
102	Project 2009-21	Project 2009-21 - Cyber Security Ninety-day Response_rc	Recirculation Ballot	12/3/2009	12/14/2009	Quorum: 93.33% Approval: 85.55%			
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%			

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
109	Project 2009-27	Project 2009-27 - Interpretation - TOP-002-2a for FMPAA_in	Initial Ballot	2/10/2010	2/22/2010	Quorum: 84.98% Approval: 90.82%			
110	Project 2009-28	Project 2009-28 - Interpretation - EOP-001-1 and EOP-001-2 for FMPP_in	Initial Ballot	2/10/2010	2/22/2010	Quorum: 87.36% Approval: 91.79%			
111	Project 2009-29	Project 2009-29 - Interpretation - TOP-002-2a for FMPP_in	Initial Ballot	2/11/2010	2/22/2010	Quorum: 84.34% Approval: 84.56%			
112	Project 2009-19	Project 2009-19 - Interpretation - BAL-002-0 Northwest Power Pool RSG_in	Initial Ballot	2/15/2010	2/26/2010	Quorum: 89.83% Approval: 48.60%			
113	Project 2009-20	Project 2009-20 - Interpretation - BAL-003-0 - Energy Mark, Inc._rc	Recirculation Ballot	2/16/2010	2/26/2010	Quorum: 92.44% Approval: 91.90%			
114	Project 2009-30	Project 2009-30 - Interpretation - PRC-001-1 for WPSC_in	Initial Ballot	2/15/2010	2/26/2010	Quorum: 89.51% Approval: 48.74%			
115	Project 2006-02	Project 2006-02 - Assess Transmission Future Needs - TPL-001-1_in	Initial Ballot	2/19/2010	3/1/2010	Quorum: 91.38% Approval: 35.36%			
116	Project 2009-31	Project 2009-31 - Interpretation - TOP-001-1 for FMPP_in	Initial Ballot	3/3/2010	3/16/2010	Quorum: 88.24% Approval: 98.27%			
117	Project 2009-06	Project 2009-06 - Facility Ratings: FAC-008-2	Recirculation Ballot	3/8/2010	3/18/2010	Quorum: 93.71% Approval: 78.15%			
118	Project 2009-32	Project 2009-32 - Interpretation - EOP-003-1 for FMPP_rb	Re-ballot	3/10/2010	3/31/2010	Quorum: 91.37% Approval: 77.66%			
119	Project 2009-23	Project 2009-23 - Interpretation - CIP-004-2 - U.S. Army Corps of Engineers (Revision 1)_in	Initial Ballot	3/29/2010	4/8/2010	Quorum: 88.52% Approval: 63.43%			
120	Project 2008-09	Project 2008-09 - Interpretation - RECM - Revision 3_in	Initial Ballot	4/15/2010	4/26/2010	Quorum: 81.97% Approval: 98.64%			
121	SPM	Standards Process Manual Revisions_in	Initial Ballot	4/19/2010	4/29/2010	Quorum: 87.82% Approval: 80.48%			
122	Project 2009-17	Project 2009-17 - Interpretation Y-W Electric and Tri-State (Revision 2)_in	Initial Ballot	4/28/2010	5/10/2010	Quorum: 83.15% Approval: 74.55%			
123	SPM	Standards Process Manual Revisions_rc	Recirculation Ballot	4/30/2010	5/10/2010	Quorum: 93.73% Approval: 86.69%			
124	Project 2010-11	Project 2010-11 SAR for TPL Table 1 Order_in	Initial Ballot	5/17/2010	5/27/2010	Quorum: 84.41% Approval: 63.75%			
125	Project 2010-09	Project 2010-09: NUC Implementation Plans for CIP Version 2 and Version 3_in	Initial Ballot	5/19/2010	6/1/2010	Quorum: 84.83% Approval: 90.83%			
126	Project 2010-09	Project 2010-09: NUC Implementation Plans for CIP Version 2 and Version 3_rc	Recirculation Ballot	6/22/2010	7/2/2010	Quorum: 89.10% Approval: 87.24%			
127	Project 2006-04	Project 2006-04 - Backup Facilities - Revision 1_in	Initial Ballot	6/23/2010	7/6/2010	Quorum: 89.05% Approval: 79.45%			
128	Project 2006-08	Project 2006-08 - Reliability Coordination - Transmission Loading Relief_in	Initial Ballot	6/23/2010	7/6/2010	Quorum: 87.04% Approval: 84.98%			
129	Project 2007-01	Project 2007-01 Underfrequency Load Shedding: PRC-006-1 and EOP-003-1	Initial Ballot	7/7/2010	7/17/2010	Quorum: 86.94% Approval: 43.13%			
130	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005-2	Initial Ballot	7/8/2010	7/17/2010	Quorum:91.12 % Approval: 22.91%			
131	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005-2	Non-binding Poll	7/8/2010	7/17/2010	Quorum: 86.00% Approval: 28.00%			
132	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: Protection System definition	Initial Ballot	7/8/2010	7/17/2010	Quorum: 87.85% Approval: 39.35%			
133	Project 2007-07	Project 2007-07 Vegetation Management: FAC-003-2	Initial Ballot	7/9/2010	7/19/2010	Quorum: 86.18% Approval: 65.93%			
134	Project 2006-04	Prokect 2006-04 - Backup Facilities - Revision 1_rc	Recirculation Ballot	7/16/2010	7/26/2010	Quorum: 93.43% Approval: 85.22%			
135	Project 2007-17	Project 2007-17 Protection System Maintenance: Protection System definition	Successive Ballot	7/23/2010	8/2/2010	Quorum: 94.70% Approval: 58.61%			
136	Project 2007-01	Project 2007-01 Underfrequency Load Shedding: PRC-006-1 and EOP-003-1	Successive Ballot	7/24/2010	8/3/2010	Quorum: 92.99% Approval: 49.61%			
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%			

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
145	Project 2007-01	Project 2007-01 Underfrequency Load Shedding: PRC-006-1 and EOP-003-1	Recirculation Ballot	10/18/2010	10/28/2010	Quorum: 89.84% Approval: 84.67%			
146	Project 2008-06	Project 2008-06 Cyber Security 706 (Version 4 CIP Standards)_in	Initial Ballot	10/20/2010	11/3/2010	Quorum: 93.66% Approval: 43.33%			
147	Project 2010-10	Project 2010-10 FAC-013-2 Planning Transfer Capability_in	Initial Ballot	10/20/2010	11/3/2010	Quorum: 88.54% Approval: 39.85%			
148	2010 SPM	2010 Standard Processes Manual (Proposed Changes)_in	Initial Ballot	10/28/2010	11/7/2010	Quorum: 81.61% Approval: 93.72%			
149	Project 2007-17	Project 2007-17 Protection System Maintenance: Protection System definition	Recirculation Ballot	11/1/2010	11/11/2010	Quorum: 89.41% Approval: 86.83%			
150	2010 SPM	2010 Standard Processes Manual (Proposed Changes)_rc	Recirculation Ballot	11/9/2010	11/13/2010	Quorum: 87.00% Approval: 92.88%			
151	Project 2009-17	Project 2009-17 - Interpretation Y-W Electric and Tri-State (Revision 2)_rc	Recirculation Ballot	11/19/2010	12/3/2010	Quorum: 87.81% Approval: 82.41%			
152	Project 2008-06	Project 2008-06 Cyber Security 706 (Version 4 CIP Standards)_sb_in	Initial Ballot	12/1/2010	12/10/2010	Quorum: 87.07% Approval: 77.06%			
153	Project 2010-15	Project 2010-15 - Expedited Action Revisions to CIP-005-3	Initial Ballot	12/2/2010	12/11/2010	Quorum: 84.46% Approval: 42.89%			
154	Project 2007-04	Project 2007-04 - Certifying System Operators: PER-003-1	Recirculation Ballot	12/2/2010	12/13/2010	Quorum: 95.50% Approval: 86.91%			
155	Project 2010-13	Project 2010-13 - Relay Loadability Order - PRC-023	Initial Ballot	12/7/2010	12/16/2010	Quorum: 88.00% Approval: 51.51%			
156	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005-2	Successive Ballot	12/10/2010	12/20/2010	Quorum: 79.88% Approval: 44.65%			
157	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005-2	Non-binding Poll	12/10/2010	12/20/2010	Quorum: 78.00% Approval: 53.00%			
158	Project 2008-06	Project 2008-06 Cyber Security 706 (Version 4 CIP Standards)_sb_rc	Recirculation Ballot	12/20/2010	12/30/2010	Quorum: 90.49% Approval: 80.56%			
159	Project 2010-11	Project 2010-11 TPL Table 1 Footnote B SAR_in	Recirculation Ballot	12/27/2010	1/5/2011	Quorum: 90.42% Approval: 83.33%			
160	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-002-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.62% Approval: 22.09%	Oppose 12/16/11		
161	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-003-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.62% Approval: 33.49%	Oppose 12/16/11		
162	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-004-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.60% Approval: 26.82%	Oppose 12/16/11		
163	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-005-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.60% Approval: 28.04%	Oppose 12/16/11		
164	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-006-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.61% Approval: 29.60%	Oppose 12/16/11		
165	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-007-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.61% Approval: 24.15%	Oppose 12/16/11		
166	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-008-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 94.02% Approval: 34.30%	Oppose 12/16/11		
167	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-009-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.61% Approval: 27.28%	Oppose 12/16/11		
168	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-010-1	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.61% Approval: 26.61%	Oppose 12/16/11		
169	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-011-1	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.61% Approval: 29.88%	Oppose 12/16/11		
170	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Implementation	Initial Ballot	12/16/2011	1/6/2011	Quorum: 92.15% Approval: 42.06%	Oppose 12/16/11		
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		

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181	Project 2009-06	Project 2009-06 - Facility Ratings: FAC-008-3	Initial Ballot	4/21/2011	5/2/2011	Quorum: 86.01% Approval: 48.74%	Abstain 4/26/11		
182	Project 2009-06	Project 2009-06 - Facility Ratings: FAC-008-3	Non-binding Poll	4/21/2011	5/2/2011	Quorum: 75.58% Approval: 73.00%			
183	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing: PRC-005	Successive Ballot	5/3/2011	5/12/2011	Quorum: 78.33% Approval: 67.00%	No Recommendation		
184	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing: PRC-005	Non-binding Poll	5/3/2011	5/12/2011	Quorum: 75.00% Approval: 66.00%			
185	Project 2009-06	Project 2009-06 - Facility Ratings: FAC-008-3	Recirculation Ballot	5/12/2011	5/23/2011	Quorum: 91.25% Approval: 78.92%	Support 5/12/11		
186	Project 2006-02	Project 2006-02 - Assess Transmission and Future Needs - TPL-001 through TPL-006	Successive Ballot	5/18/2011	5/31/2011	Quorum: 92.07% Approval: 73.99%			
187	Project 2006-02	Project 2006-02 - Assess Transmission and Future Needs - TPL-001 through TPL-006	Non-binding Poll	5/18/2011	5/31/2011	Quorum: 86.79% Approval: 71.9%			
188	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-001-2, TOP-002-2 and TOP-003-2	Initial Ballot	5/31/2011	6/9/2011	Quorum: 88.47% Approval: 48.64%	Oppose 5/31/11		
189	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-001-2, TOP-002-2 and TOP-003-2	Non-binding Poll	5/31/2011	6/9/2011	Quorum: 84.18% Approval: 41.00%			
190	Project 2007-17	Project 2007-17 – Protection System Maintenance and Testing – PRC-005	Recirculation Ballot	6/20/2011	6/30/2011	Quorum: 82.97% Approval: 64.76%	Support 6/28/11		
191	Project 2007-17	Project 2007-17 – Protection System Maintenance and Testing – PRC-005	Non-binding Poll	6/20/2011	6/30/2011	Quorum: 52.63% Approval: 60.00%			
192	Project 2006-02	Project 2006-02 - Assess Transmission and Future Needs	Recirculation Ballot	7/13/2011	7/22/2011	Quorum: 94.33% Approval: 75.37%			
193	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-002-3	Recirculation Ballot	7/15/2011	7/25/2011	Quorum: 94.13% Approval: 76.99%	Support 7/22/11		
194	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-005-4	Recirculation Ballot	7/15/2011	7/25/2011	Quorum: 94.13% Approval: 75.17%	Support 7/22/11		
195	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-014-2	Recirculation Ballot	7/15/2011	7/25/2011	Quorum: 94.13% Approval: 76.27%	Support 7/22/11		
196	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-002-3	Non-binding Poll	7/15/2011	7/25/2011	Quorum: 75.37% Approval: 93.00%			
197	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-005-4	Non-binding Poll	7/15/2011	7/25/2011	Quorum: 75.66% Approval: 93.00%			
198	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-014-2	Non-binding Poll	7/15/2011	7/25/2011	Quorum: 75.37% Approval: 89.00%			
199	Project 2007-09	Project 2007-09 – Generator Verification: MOD-026-1	Initial Ballot	7/22/2011	8/1/2011	Quorum: 90.25% Approval: 46.53%	No Consensus 7/28/11		
200	Project 2007-09	Project 2007-09 – Generator Verification: MOD-026-1	Non-binding Poll	7/22/2011	8/1/2011	Quorum: 88.75% Approval: 56.00%			
201	Project 2007-09	Project 2007-09 – Generator Verification: PRC-024-1	Initial Ballot	7/22/2011	8/1/2011	Quorum: 90.82% Approval: 18.23%	No Consensus 7/28/11		
202	Project 2007-09	Project 2007-09 – Generator Verification: PRC-024-1	Non-binding Poll	7/22/2011	8/1/2011	Quorum: 88.35% Approval: 20.79%			
203	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing: PRC-005	Initial Ballot	9/19/2011	9/29/2011	Quorum: 84.86% Approval: 61.10%	Support 9/21/11		
204	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing: PRC-005	Non-binding Poll	9/19/2011	9/29/2011	Quorum: 83.13% Approval: 68.68%			
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		

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
217	Project 2007-12	Project 2007-12 - Frequency Response: BAL-003-1	Initial Ballot	11/30/2011	12/9/2011	Quorum: 93.92% Approval: 30.82%	Oppose 12/5/11		
218	Project 2007-12	Project 2007-12 - Frequency Response: BAL-003-1	Non-binding Poll	11/30/2011	12/9/2011	Quorum: 89.49% Approval: 36.00%			
219	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Initial Ballot	12/2/2011	12/12/2011	Quorum: 87.97% Approval: 36.21%	Oppose 12/5/11		
220	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Non-binding Poll	12/2/2011	12/12/2011	Quorum: 85.28% Approval: 45.00%			
221	Project 2008-10	Project 2008-10 - Interpretation of CIP-006-x R1 for Progress Energy	Recirculation Ballot	12/9/2011	12/19/2011	Quorum: 88.02% Approval: 96.04%	Support 11/14/11		
222	Project 2011-INT-01	Project 2011-INT-01 - Interpretation of MOD-028 for Florida Power & Light Company	Recirculation Ballot	12/12/2011	12/22/2011	Quorum: 90.10% Approval: 92.49%	Support 11/8/11		
223	Project 2009-22	Project 2009-22 - Interpretation of COM-002-2 R2 by the IRC	Recirculation Ballot	12/14/2011	12/23/2011	Quorum: 92.00% Approval: 94.58%	Support 11/8/11		
224	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-001-1	Recirculation Ballot	12/14/2011	12/23/2011	Quorum: 88.48% Approval: 90.10%	Support 11/10/11		
225	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-003-3	Recirculation Ballot	12/14/2011	12/23/2011	Quorum: 87.17% Approval: 85.38%	Support 11/10/11		
226	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-003-X	Recirculation Ballot	12/14/2011	12/23/2011	Quorum: 86.91% Approval: 85.03%	Support 11/10/11		
227	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: PRC-004-2.1a	Recirculation Ballot	12/14/2011	12/23/2011	Quorum: 86.65% Approval: 96.43%	Support 11/10/11		
228	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-001-2	Successive Ballot	1/3/2012	1/12/2012	Quorum: 82.04% Approval: 59.93%	Oppose 1/9/12		
229	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-002-3	Successive Ballot	1/3/2012	1/12/2012	Quorum: 82.04% Approval: 77.08 %	Support 1/9/12		
230	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-003-2	Successive Ballot	1/3/2012	1/12/2012	Quorum: 82.04% Approval: 78.95%	Support 1/9/12		
231	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-001-1	Non-binding Poll	1/4/2012	1/13/2012	Quorum: 78.27% Approval: 93.00%			
232	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-002-3	Non-binding Poll	1/9/2012	1/18/2012	Quorum: 76.41% Approval: 71.42%			
233	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-001-2	Non-binding Poll	1/9/2012	1/19/2012	Quorum: 81.50% Approval: 67.61%			
234	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-003-2	Non-binding Poll	1/9/2012	1/19/2012	Quorum: 81.50% Approval: 70.28%			
235	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001-2	Successive Ballot	1/30/2012	2/9/2012	Quorum: 81.82% Approval: 54.64%	Oppose 2/7/12		
236	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-002-3	Successive Ballot	1/30/2012	2/9/2012	Quorum: 82.11% Approval: 80.62%	Support 2/7/12		
237	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-001-3	Successive Ballot	1/30/2012	2/9/2012	Quorum: 81.82% Approval: 80.21%	Support 2/7/12		
238	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001-2	Non-binding Poll	1/30/2012	2/9/2012	Quorum: 80.35% Approval: 71.35%			
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		

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
253	Project 2007-09	Project 2007-09 Generator Verification: MOD-025-2	Non-binding Poll	4/6/2012	4/16/2012	Quorum: 86.82% Approval: 43.72%			
254	Project 2007-09	Project 2007-09 Generator Verification: MOD-027-1	Non-binding Poll	4/6/2012	4/16/2012	Quorum: 86.04% Approval: 38.56%			
255	Project 2007-09	Project 2007-09 Generator Verification: PRC-019-1	Non-binding Poll	4/6/2012	4/16/2012	Quorum: 86.53% Approval: 46.38%			
256	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: PRC-005-1.1a	Initial Ballot	4/6/2012	4/16/2012	Quorum: 88.95% Approval: 92.41%	Support 4/16/12		
257	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-001-2	Successive Ballot	4/11/2012	4/20/2012	Quorum: 78.28%% Approval: 75.44%			
258	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-002-3	Successive Ballot	4/11/2012	4/20/2012	Quorum: 78.02% Approval: 87.22%			
259	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-003-2	Successive Ballot	4/11/2012	4/20/2012	Quorum: 78.28% Approval: 80.11%			
260	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-001-2	Non-binding Poll	4/11/2012	4/23/2012	Quorum: 77.21% Approval: 69.84%			
261	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-003-2	Non-binding Poll	4/11/2012	4/23/2012	Quorum: 77.48% Approval: 67.64%			
262	Project 2009-26	Project 2009-26 - Interpretation of CIP-004-1 by WECC	Recirculation Ballot	4/20/2012	4/30/2012	Quorum: 90.96% Approval: 80.08%	Support 3/16/12		
263	Project 2010-INT-05	Interpretation 2010-INT-05 - Interpretation of CIP-002-1 R3 for Duke Energy	Recirculation Ballot	4/20/2012	4/30/2012	Quorum: 92.68% Approval: 94.61%	Support 3/16/12		
264	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-003-3	Recirculation Ballot	4/24/2012	5/3/2012	Quorum: 81.72% Approval: 87.34%			
265	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-003-X	Recirculation Ballot	4/24/2012	5/3/2012	Quorum: 81.94% Approval: 87.32%			
266	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: PRC-005-1.1b	Recirculation Ballot	4/24/2012	5/3/2012	Quorum: 90.44% Approval: 93.23%			
267	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-001-2	Recirculation Ballot	4/27/2012	5/6/2012	Quorum: 79.36% Approval: 76.84%	Abstain 4/19/12		
268	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-002-3	Recirculation Ballot	4/27/2012	5/6/2012	Quorum: 79.36% Approval: 88.11%	Support 4/19/12		
269	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-003-2	Recirculation Ballot	4/27/2012	5/6/2012	Quorum: 79.36% Approval: 80.79%	Support 4/19/12		
270	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-002-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 86.63% Approval: 37.37%	Abstain 5/17/12		
271	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-003-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 87.45% Approval: 60.55%	Abstain 5/17/12		
272	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-004-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 87.40% Approval: 38.81%	Abstain 5/17/12		
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		

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
289	Project 2007-06	Project 2007-06 - System Protection Coordination: PRC-027-1	Initial Ballot	6/26/2012	7/5/2012	Quorum: 84.24% Approval: 23.82%	Oppose 6/27/12		
290	Project 2007-06	Project 2007-06 - System Protection Coordination: PRC-027-1	Non-binding Poll	6/26/2012	7/5/2012	Quorum: 82.26% Approval: 25.19%			
291	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-002-3	Recirculation Ballot	6/27/2012	7/6/2012	Quorum: 85.34% Approval: 81.71%			
292	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-001-3	Recirculation Ballot	6/27/2012	7/6/2012	Quorum: 85.04% Approval: 81.72%			
293	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-002-3	Non-binding Poll	6/27/2012	7/6/2012	Quorum: 84.16% Approval: 79.16%			
294	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-001-3	Non-binding Poll	6/27/2012	7/6/2012	Quorum: 83.87% Approval: 86.91%			
295	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001-2	Successive Ballot	6/27/2012	7/9/2012	Quorum: 75.37% Approval: 72.16%	No Consensus 7/5/12		
296	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001-2	Non-binding Poll	6/27/2012	7/11/2012	Quorum: 75.37% Approval: 73.71%			
297	Project 2011-INT-02	Project 2011-INT-02 - Rapid Revision of VAR-002 for Constellation	Recirculation Ballot	7/18/2012	7/27/2012	Quorum: 90.97% Approval: 69.81%	Support 6/26/12		
298	Project 2011-INT-02	Project 2011-INT-02 - Rapid Revision of VAR-002 for Constellation	Non-binding Poll	7/18/2012	7/27/2012	Quorum: 81.31% Approval: 60.93%			
299	Project 2010-INT-01	Project 2010-INT-01 - Rapid Revision of TOP-006 for FMPP	Initial Ballot	7/20/2012	7/30/2012	Quorum: 80.39% Approval: 79.28%	Oppose 7/20/12		
300	Project 2010-INT-01	Project 2010-INT-01 - Rapid Revision of TOP-006 for FMPP	Non-binding Poll	7/20/2012	7/30/2012	Quorum: 78.26% Approval: 76.07%			
301	Project 2012-08.1	Project 2012-08.1 - Phase 1 of Glossary Updates: Statutory Definitions	Initial Ballot	7/24/2012	8/2/2012	Quorum: 83.11% Approval: 54.16%	Oppose 7/20/12		
302	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005	Successive Ballot	8/17/2012	8/27/2012	Quorum: 78.11% Approval: 80.31%	Support 6/22/12		
303	Project 2009-19	Project 2009-19 – Interpretation of BAL-002 by NWPP Reserve Sharing Group	Successive Ballot	8/23/2012	9/4/2012	Quorum: 79.21% Approval: 87.78%	Support 2/22/10		
304	Project 2010-05.1	Project 2010-05.1 –Protection Systems: Phase 1 (Misoperations): PRC-004-3	Initial Ballot	8/29/2012	9/7/2012	Quorum: 86.71% Approval: 37.68%	Support 9/5/12		
305	Project 2010-05.1	Project 2010-05.1 –Protection Systems: Phase 1 (Misoperations): PRC-004-3	Non-binding Poll	8/29/2012	9/7/2012	Quorum: 84.17% Approval: 37.36%			
306	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001-2	Recirculation Ballot	9/6/2012	9/17/2012	Quorum: 80.35% Approval: 75.01%			
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		

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
325	SPM-SPIG	Standard Processes Manual Revisions to Implement SPIG Recommendations	Initial Ballot	10/3/2012	10/12/2012	Quorum: 87.50% Approval: 63.25%	Support 10/4/12		
326	VRFs and VSLs	Revisions to Outstanding VRFs and VSLs	Non-binding Poll	10/10/2012	10/23/2012	Quorum: 78.57% Approval: 73.02%			
327	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005	Recirculation Ballot	10/15/2012	10/24/2012	Quorum: 81.08% Approval: 80.51%	Support 6/22/12		
328	Project 2007-09	Project 2007-09_Generator Verification: MOD-026-1	Successive Ballot	10/19/2012	10/31/2012	Quorum: 75.55% Approval: 76.50%			
329	Project 2007-09	Project 2007-09_Generator Verification: PRC-024-1	Successive Ballot	10/19/2012	10/31/2012	Quorum: 75.00% Approval: 57.24%			
330	Project 2007-09	Project 2007-09_Generator Verification: MOD-025-2	Successive Ballot	10/19/2012	10/31/2012	Quorum: 83.61% Approval: 68.31%			
331	Project 2007-09	Project 2007-09_Generator Verification: MOD-027-1	Successive Ballot	10/19/2012	10/31/2012	Quorum: 82.34% Approval: 71.53%			
332	Project 2007-09	Project 2007-09_Generator Verification: PRC-019-1	Successive Ballot	10/19/2012	10/31/2012	Quorum: 82.07% Approval: 70.64%			
333	Project 2007-09	Project 2007-09_Generator Verification: MOD-026-1	Non-binding Poll	10/19/2012	10/31/2012	Quorum: 75.88% Approval: 77.10%			
334	Project 2007-09	Project 2007-09_Generator Verification: PRC-024-1	Non-binding Poll	10/19/2012	10/31/2012	Quorum: 75.40% Approval: 52.72%			
335	Project 2007-09	Project 2007-09_Generator Verification: MOD-025-2	Non-binding Poll	10/19/2012	10/31/2012	Quorum: 77.94% Approval: 64.24%			
336	Project 2007-09	Project 2007-09_Generator Verification: MOD-027-1	Non-binding Poll	10/19/2012	10/31/2012	Quorum: 78.06% Approval: 68.93%			
337	Project 2007-09	Project 2007-09_Generator Verification: PRC-019-1	Non-binding Poll	10/19/2012	10/31/2012	Quorum: 78.51% Approval: 63.63%			
338	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-002-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.33% Approval: 78.59%	Support 10/4/12		
339	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-003-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.33% Approval: 92.75%	Support 10/4/12		
340	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-004-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 89.73%	Support 10/4/12		
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		

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
361	SPM-SPIG	Standard Processes Manual Revisions to Implement SPIG Recommendations	Successive Ballot	12/11/2012	12/20/2012	Quorum: 83.24% Approval: 84.48%	Support 12/19/12		
362	Project 2007-09	Project 2007-09 Generator Verification: MOD-025-2	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 86.89% Approval: 73.06%			
363	Project 2007-09	Project 2007-09 Generator Verification: MOD-026-1	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 79.00% Approval: 79.36%			
364	Project 2007-09	Project 2007-09 Generator Verification: MOD-027-1	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 86.68% Approval: 74.27%			
365	Project 2007-09	Project 2007-09 Generator Verification: PRC-019-1	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 85.87% Approval: 73.63%			
366	Project 2007-12	Project 2007-12 - Frequency Response: BAL-003-1	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 86.19% Approval: 76.53%			
367	Project 2007-09	Project 2007-09 - Generator Verification: PRC-024-1	Successive Ballot	1/2/2013	1/11/2013	Quorum: 78.16% Approval: 60.31%	Support 1/11/13		
368	Project 2007-09	Project 2007-09 - Generator Verification - PRC-024-1	Non-binding Poll	1/2/2013	1/11/2013	Quorum: 76.38% Approval: 55.68%			
369	Project 2010-11	Project 2010-11 Successive Ballot December 2012 in	Successive Ballot	1/2/2013	1/11/2013	Quorum: 85.47% Approval: 65.77%	No Consensus 1/11/13		
370	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-012-1	Initial Ballot	1/4/2013	1/14/2013	Quorum: 83.94% Approval: 21.80%	Oppose 1/11/13		
371	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-012-1	Non-binding Poll	1/4/2013	1/14/2013	Quorum: 82.23% Approval: 24.27%			
372	Project 2013-02	Project 2013-02 - Paragraph 81	Recirculation Ballot	1/8/2013	1/17/2013	Quorum: 84.60% Approval: 95.22%	Support 12/10/12		
373	Project 2012-INT-05	Interpretation 2012-INT-05: CIP-002-3 for OGE	Recirculation Ballot	1/14/2013	1/23/2013	Quorum: 87.13% Approval: 99.09%	Support 12/19/12		
374	SPM-SPIG	Standard Processes Manual Revisions to Implement SPIG Recommendations	Recirculation Ballot	1/18/2013	1/28/2013	Quorum: 85.90% Approval: 85.57%	Support 12/19/12		
375	Project 2010-11	Project 2010-11 Recirculation Ballot Jan 2013 in	Recirculation Ballot	1/22/2013	1/31/2013	Quorum: 88.55% Approval: 69.63%	No Consensus 1/11/13		
376	Project 2012-INT-02	Interpretation 2012-INT-02 - Interpretation of TPL-003-0a and TPL-004-0 for SPCS	Recirculation Ballot	1/22/2013	1/31/2013	Quorum: 85.67% Approval: 77.61%	Oppose 12/5/12		
377	Project 2010-05.1	Project 2010-05.1 –Protection Systems: Phase 1 (Misoperations): PRC-004-3	Successive Ballot	2/11/2013	2/20/2013	Quorum: 77.62% Approval: 50.66%	Support 9/5/12		
378	Project 2010-05.1	Project 2010-05.1 –Protection Systems: Phase 1 (Misoperations): PRC-004-3	Non-binding Poll	2/11/2013	2/20/2013	Quorum: 75.38% Approval: 50.60%			
379	Project 2007-09	Project 2007-09 - Generator Verification: PRC-024-1	Successive Ballot	2/15/2013	2/28/2013	Quorum: 78.80% Approval: 89.01%	Support 1/11/13		
380	Project 2007-09	Project 2007-09 - Generator Verification: PRC-024-1	Non-binding Poll	2/15/2013	2/28/2013	Quorum: 76.38% Approval: 84.24%			
381	Project 2010-13.2	Project 2010-13.2 Phase 2 of Relay Loadability: Generation	Initial Ballot	3/1/2013	3/11/2013	Quorum: 76.36% Approval: 54.65%			
382	Project 2012-08.1	Project 2012-08.1 - Phase 1 of Glossary Updates: Statutory Definitions	Successive Ballot	3/13/2013	3/22/2013	Quorum: 77.48% Approval: 84.27%	No Consensus 3/22/13		NPCC to abstain - international nature of the ERO and BPS is not used in Reliability Standards
383	Project 2012-INT-04	Project 2012-INT-04 - Interpretation of CIP-007-3 for ITC	Initial Ballot	3/13/2013	3/22/2013	Quorum: 88.58% Approval: 97.18%	Support 3/14/13		
384	Project 2012-INT-06	Project 2012-INT-06 - Interpretation of CIP-003-3 for Consumers Energy	Initial Ballot	3/13/2013	3/22/2013	Quorum: 88.52% Approval: 98.89%	Support 3/14/13		
385	Project 2007-09	Project 2007-09 - Generator Verification: PRC-024-1	Recirculation Ballot	3/18/2013	3/27/2013	Quorum: 81.33% Approval: 89.44%	Support 1/11/13		

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386	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Successive Ballot	3/27/2013	4/5/2013	Quorum: 78.39% Approval: 57.50%	No Consensus 4/4/13		The RSC did not reach a full consensus however the majority of respondents had indicated they will support the standard - see comment form for further details. Some believe the standard is not necessary and that existing whitepapers alleviate the need for it. In recognition of the NERC BOT's expectations that COM-003 will be approved by the industry and brought before them for approval, NPCC has voted affirmatively and will supply comments for the record outlining our concerns.
387	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Non-binding Poll	3/27/2013	4/5/2013	Quorum: 77.97% Approval: 54.28%			
388	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-001-2	Initial Ballot	4/16/2013	4/25/2013	Quorum: 88.60% Approval: 66.98%	No Consensus 4/23/13		The majority of NPCC's Balancing Authorities have indicated support for the standard, however NPCC as the Regional Entity has concerns based on results of the field trials that were conducted. These field trials have indicated the potential for an increased number of SOL violations as well as potential for increased ACE due to large inadvertent flows with the proposed BAAL limits based on frequency triggers. To be respectful of the positions of the NPCC BAs who will have to implement this new methodology and the support expressed, NPCC as the Regional Entity will cast an Abstention
389	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-002-2	Initial Ballot	4/16/2013	4/25/2013	Quorum: 88.51% Approval: 42.75%	Oppose 4/23/13		There is a lack of technical justification for the 500 MW threshold within the standard-NPCC will submit suggested improvements
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: %			

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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.]		[illegible] organizations support the standard as written however some members expressed concern that in order to measure compliance with R1 and R2, the standard will require all Reliability Directives to be investigated to determine if RC approved and documented communication protocols have been violated. Also it was identified that TO, BA communication protocols would have to approved by the RC potentially causing some legal issues if protocols aren't approved and casts question on the enforcement of those protocols. NPCC will be submitting some helpful comments should the standard pass and some non-substantive revision be performed prior to the "final" (previously named recirculation) ballot.
401	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-003	Non-binding Poll	7/10/2013	7/19/2013	Quorum: 76.20% Approval: 55.37%			
402	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-025	Successive Ballot	7/10/2013	7/19/2013	Quorum: 85.05% Approval: 72.43%	Support 7/19/13		
403	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-025	Non-binding Poll	7/10/2013	7/19/2013	Quorum: 82.51% Approval: 64.59%			
404	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-001-2	Final Ballot	7/16/2013	7/25/2013	Quorum: 92.31% Approval: 74.54%	No Consensus 7/22/13		The RSC has not reached a full consensus however the majority are in support. Issues outstanding for those not in support are concern over "hitting limits" more frequently and potential issues with BA's potentially "dragging" on the interconnection. NPCC will be voting affirmative on the standard.

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
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%			
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%			

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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		
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	

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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	
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	

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476	Project 2012-13	Project 2012-13 - NUC - Nuclear Plant Interface Coordination	Initial Ballot	5/13/2014	5/22/2014	Quorum: 80.60% Approval: 97.36%	Support--5/20/14	Affirmative		
477	Project 2007-17.3	Project 2007-17.3 - Protection System Maintenance and Testing - Phase 3 (Sudden Pressure Relays) - PRC-005-X	Initial Ballot	5/23/2014	6/2/2014	Quorum: 85.42% Approval: 47.89%	Support	Affirmative		
478	Project 2010-13.3	Project 2010-13.3 - Phase 3 of Relay Loadability: Stable Power Swings	Initial Ballot	5/30/2014	6/9/2014	Quorum: 79.06% Approval: 17.02%	Does not Support--6/6/14	Negative		
475	Project 2010-02	Project 2010-02 - Connecting Facilities to the Grid - FAC-001-2 and FAC-002-2	Final Ballot	6/12/2014	6/23/2014	Quorum: Approval: 89.03%/83.46%	Support	Affirmative		
479	Project 2007-11	Project 2007-11 - Disturbance Monitoring - PRC-002-2	Additional Ballot	6/13/2014	6/23/2014	Quorum: 77.69% Approval: 52.29%	Support	Affirmative	Extended to achieve a quorum.	
480	Project 2010-05.1	Project 2010-05.1 - Protection System: Phase 1 (Misoperations) - PRC-004	Additional Ballot	6/20/2014	7/9/2014	Quorum: 76.98% Approval: 74.53%	Support	Affirmative	Extended to achieve a quorum.	Last RSC Meeting
481	Project 2014-03	Project 2014-03 - Revisions to TOP/IRO Reliability Standards	Ballot	6/23/2014	7/2/2014	Quorum: 82.32%/82.59%/82.59%/82.85%/82.85%/82.06%/82.59%/82.85%/82.85%/81.00%/80.74% 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 http://www.nerc.com/pa/Stand/Pages/Project-2014-XX-Critical-Infrastructure-Protection-Version-5-Revisions.aspx	Final Ballot	7/7/2014	7/16/2014	Quorum: 80.73%/80.49%/80.00%/80.24%/80.24%/80.49%/80.24%/78.29% Approval: 35.67%/80.76%/76.24%/78.41%/85.32%/49.42%/82.55%/78.58%	CIP-003 No CIP-004 Yes CIP-006 Yes CIP-007 Yes CIP-009 Yes CIP-010 Yes CIP-011 Yes Definitions Yes Support--7/14/14			
484	Project 2010-05.2	Project 2010-05.2 – Special Protection Systems (Phase 2 of Protection Systems)	Final Ballot	7/16/2014	7/25/2014	Quorum: 78.92% Approval: 58.88%	Support--7/23/14			
485	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Final Ballot	7/18/2014	7/28/2014	Quorum: 79.49%/80.15%/80.00%/80.83%/80.36% Approval: 91.38%/92.20%/89.51%/90.58%/87.09%	Support--7/24/14	Affirmative		
486	Project 2012-13	Project 2013-03 Geomagnetic Disturbance Mitigation	Final Ballot	7/21/2014	7/30/2014	Quorum: 82.67% Approval: 55.77%		Affirmative		
487	Project 2012-13	Project 2008-02 Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS)	Initial Ballot	7/29/2014	8/7/2014	Quorum: 76.37% Approval: 76.91%		Affirmative		
488	Project 2012-13	Project 2009-03 Emergency Operations	Initial Ballot	8/6/2014	8/15/2014	Quorum: 77.66% Approval: 42.27%	Negative--8/14/14	Negative		
489	Project 2014-01	Project 2010-05.1 - Protection System: Phase 1 (Misoperations) - PRC-004	Final Ballot	7/29/2014	8/7/2014	Quorum: 77.94% Approval: 79.75%	Support	Affirmative		
490	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Final Ballot	8/27/2014	9/5/2014	Quorum: 85.32%/86.01% Approval: 95.35%/95.86%	Support	Affirmative		
491	Project 2007-17.3	Project 2007-17.3 - Protection System Maintenance and Testing - Phase 3	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%	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			

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						Approval: 76.12%/74.23%/75.67%/85.49%/75.96%/78.67%/48.73%/78.87%/87.03%/93.34%/90.13%	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%	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		
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		

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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		
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		

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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		
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%	Affirmative--7/24/15		

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: 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% Approval: 87.36%	Affirmative--9/18/15		
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%	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: 78.87%			
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% Approval: 80.36%/93.43%	Affirmative--3/10/16		
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		

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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% 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% Approval: 42.74%	Affirmative--9/1/17		
582	Project 2015-10	Project 2015-10 Single Points of Failure TPL-001	Initial Ballot	9/8/2017	10/23/2017	Quorum: 82.71% Approval: 30.50%	Abstain--10/18/17		
583	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation TPL-007-2	Final Ballot	10/20/2017	10/30/2017	Quorum: 88.74% Approval: 73.35%	Affirmative--8/3/17		
584	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-002-6	Initial Ballot	9/14/2017	10/30/2017	Quorum: 85.40% Approval: 66.78%	Affirmative--10/30/17		
585	Project 2015-09	Project 2015-09 Establish and Communicate System Operating Limits	Initial Ballot	11/3/2017	11/13/2017	Quorum: 87.01%/86.90%/86.90%/85.57%/85.85 Approval: 58.12%/63.17%/56.55%/76.40%/68.59%	Affirmative--11/10/17		
586	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-012-1	Additional Ballot	11/20/2017	12/11/2017	Quorum:77.10% Approval: 63.91%	Affirmative--12/4/17		
587	Project 2016-04	Project 2016-04 Modifications to PRC-025-1	Additional Ballot	10/30/2017	12/13/2017	Quorum: 81.73% Approval: 88.25%	Affirmative--12/4/17		
588	Project 2016-04	Project 2016-04 Modifications to PRC-025-1	Final Ballot	1/9/2018	1/18/2018	Quorum: 82.69% Approval: 89.46%	Affirmative--12/4/17		
589	Project 2017-02	Project 2017-02 Modifications to Personnel Performance, Training and Qualifications	Initial Ballot	2/26/2018	3/7/2018	Quorum: 80.93%/81.27% Approval: 97.50%/98.91%	Affirmative--3/2/18		
590	Project 2017-02	Project 2017-02 Modifications to Personnel Performance, Training and Qualifications	Final Ballot	4/3/2018	4/12/2018	Quorum: 84.82%/84.86% Approval: 96.64%/97.88%	Affirmative--3/2/18		
591	Project 2015-10	Project 2015-10 Single Points of Failure TPL-001	Additional Ballot	2/23/2018	4/23/2018	Quorum: 80% Approval: 26.44%	Affirmative--4/16/18		
592	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-002-6	Additional Ballot	3/16/2018	4/30/2018	Quorum: 79.50% Approval: 93.31%	Affirmative--4/25/18		
593	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-012-1	Additional Ballot	3/16/2018	4/30/2018	Quorum:78.06% Approval: 83.71%	Affirmative--4/25/18		

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594	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-012-1 Control Center Definition and Implementation Plan	Initial Ballot	3/16/2018	4/30/2018	Quorum: 81.33%/81.54% Approval: 46.71%/37.98%	Negative--4/25/18		
595	Project 2017-06	Project 2017-06 Modifications to BAL-002-2	Initial Ballot	4/27/2018	5/8/2018	Quorum: 81.82% Approval: 80%	Abstain--5/7/17		
596	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-012-1	Additional Ballot	5/18/2018	7/3/2018	Quorum: 75.16% Approval: 68.45%	Affirmative--6/29/18		
597	Project 2017-06	Project 2017-06 Modifications to BAL-002-2	Final Ballot	7/5/2018	7/16/2018	Quorum: 84.42% Approval: 71.85%	Abstain--5/7/17		
598	SPM	Revisions to the NERC Standards Process Manual	Additional Ballot	7/31/2018	8/9/2018	Quorum: 80.34% Approval: 81.95%	Affirmative--8/7/18		
599	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-012-1	Final Ballot	8/3/2018	8/13/2018	Quorum:81.55% Approval: 72..55%	Affirmative--4/25/18		
600	Project 2015-10	Project 2015-10 Single Points of Failure TPL-001	Additional Ballot	9/5/2018	9/14/2018	Quorum: 75.59% Approval: 69.07%	Affirmative--9/5/18		
601	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-002-6	Initial Ballot	9/28/2018	10/9/2018	Quorum: 78.59% Approval: 55.89%	Affirmative--10/5/18		
602	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-003-8	Initial Ballot	9/28/2018	10/9/2018	Quorum: 78.77% Approval: 90.06%	Affirmative--10/5/18		
603	Project 2015-09	Project 2015-09 Establish and Communicate System Operating Limits	Additional Ballot	10/8/2018	10/17/2018	Quorum: 83.65%/84.08%/83.77%/84.82%/82.43%/82.11%/84.08%/83.60%/83.12%/80.98%/83.28% Approval: 67.65%/67.46%/53.22%/77.07%/59.02%/59.79%/75.07%/69.27%/71.98%/69.93%/82.26%	Affirmative--10/12/18		
604	Project 2018-02	Project 2018-02 Modifications to CIP-008 Cyber Security Incident Reporting	Initial Ballot	10/18/2018	10/22/2018	Quorum: 81.17% Approval: 20.02%	Reject--10/22/18		
605	Project 2015-10	Project 2015-10 Single Points of Failure TPL-001	Final Ballot	10/11/2018	10/22/2018	Quorum: 86.39% Approval: 66.69%	Affirmative--9/5/18		
606	SPM	Revisions to the NERC Standards Process Manual	Final Ballot	10/7/2018	10/29/2018	Quorum: 85.96% Approval: 81.61%	Affirmative--8/7/18		
607	Project 2018-01	Project 2018-01 Canadian-specific Revisions to TPL-007-2	Initial Ballot	11/6/2018	11/15/2018	Quorum: 77.54%/79.10% Approval: 100%/100%	Affirmative--11/6/18		
608	Project 2018-02	Project 2018-02 Modifications to CIP-008 Cyber Security Incident Reporting	Additional Ballot	11/20/2018	11/29/2018	Quorum: 94.44% Approval: 75.54%	Affirmative--11/20/18		
609	Project 2018-01	Project 2018-01 Canadian-specific Revisions to TPL-007-2	Final Ballot	11/29/2018	12/10/2018	Quorum: 80.43%/82.09% Approval: 100%/100%	Affirmative--11/6/18		
610	Project 2017-01	Project 2017-01 Modifications to BAL-003-1.1	Initial Ballot	1/8/2019	1/17/2019	Quorum: 92.02%/91% Approval: 96.41%/99.04%	Affirmative--1/14/19		
611	Project 2018-02	Project 2018-02 Modifications to CIP-008 Cyber Security Incident Reporting	Final Ballot	1/15/2019	1/22/2019	Quorum: 96.30% Approval: 77.89%	Affirmative--11/20/18		
612	Project 2018-03	Project 2018-03 Standards Efficiency Review Retirements	Initial Ballot	4/3/2019	4/12/2019	Quorum: 86.75%/87.96%/87.80%/87.58%/87.58%/87.50%/87.58%/87.34%/87.46%/86.45%/87.34%/86.77%/87.17%/87.17%/86.89%/85.71%/85.67%/86.39%	Affirmative--4/10/19 for all standards except three. Negative--4/10/19 on following standard: BRC-004-5(i), INT-010-		

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						Approval: 96.18%/98.88%/97.41%/97.79%/98.51%/89.75%/98.53%/96.60%/95.96%/96.60%/95.80%/98.95%/96.45%/96.54%/95.90%/88.42%/98.96%/97.69%	Negative--4/10/19 on following standard: PRC-004-5(i), INT-010-2.1 and FAC-0008-3		
613	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-003-8	Final Ballot	4/18/2019	4/29/2019	Quorum: 83.64% Approval: 91.44%	Affirmative--10/5/18		
614	Project 2018-03	Project 2018-03 Standards Efficiency Review Retirements	Final Ballot	4/3/2019	4/12/2019	Quorum: 90.22%/90.97%/90.85%/90.94%/90.94%/90.88%/90.60%/90.26%/90.43%/90.32%/90.26%/90.65%90.13%/90.13%/89.84%/90.06%/90.03%/89.56% Approval: 95.74%/86.66%/85.94%/96.64%/97.22%/90.19%/97.19%/95.47%/94.63%/94.34%/94.69%/96.59%95.28%/95.41%94.55%/87.12%/97.75%/96.57%	Affirmative--4/10/19 for all standards except three.		

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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

RSC Meeting #19-2, Agenda Item 6.3: Comment History

(As of 4/29/2019)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
1.	N/A	Standards Project Prioritization Reference Document and Tool	Project Prioritization Tool		1/21/11	2/10/11	Yes 2/10/11
2.	Project 2007-23	Project 2007-23 - Violation Severity Levels	VSLs		1/20/11	2/18/11	Yes 2/18/11
3.	N/A	CAN-0015--Draft CAN-0015 Unavailability of NERC Tools	CAN-0015 Unavailability of NERC Tools		2/4/11	2/18/11	Yes 2/18/11
4	N/A	CAN-0016--Draft CAN-0016 CIP-001-1 R1 - Applicability to Non-BES	CAN-0016 CIP-001-1, R1		2/4/11	2/18/11	Yes 2/18/11
5.	N/A	CAN-0018--Draft CAN-0018 FAC-008 R.1.2.1 - Terminal Equipment	CAN-0018 FAC-008, R.1.2.1		2/4/11	2/18/11	Yes 2/18/11
6.	Regional Standard	Regional Reliability Standards - PRC-006-NPCC-1 - Automatic Underfrequency Load Shedding	PRC-006-NPCC-1		1/10/11	2/24/11	
7.	Project 2007-07	Project 2007-07 - Vegetation Management - FAC-003	FAC-003-2		1/27/11	2/28/11	Yes 2/28/11
8.	N/A	CAN-0017--Draft CAN-0017 CIP-007 R5 System Access and Password Controls	CAN-0017 CIP-007, R5		2/11/11	3/4/11	Yes 3/4/11
9.	Project 2007-12	Project 2007-12 - Frequency Response	BAL-003-1		2/4/11	3/7/11	Yes 3/7/11
10.	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001, COM-002, IRO-001, and IRO-014	COM-001 COM-002 IRO-001 IRO-014		1/18/11	3/7/11	Yes 3/7/11
11.	NERC RoP	Proposed Changes to Rules of Procedure to Add Section 1700 - Challenges to Determinations	RoP Section 1700		2/14/11	3/7/11	Yes 3/7/11
12.	Project 2009-02	Project 2009-02 - Real-time Reliability Monitoring and Analysis Capabilities	Concept White Paper		2/16/11	4/4/11	Yes 4/4/11

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13.	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface	Various BAL, CIP, EOP, FAC, IRO, MOD, PER, PRC, TOP, and VAR Standards		3/4/11	4/4/11	Yes 4/4/11
14.	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting	EOP-004-2		3/9/11	4/8/11	Yes 4/8/11
15.	RFC RoP	Notice of Proposed Changes to RFC Rules of Procedure and Request for Comments			3/1/11	4/15/11	
16.	NERC RoP	Proposed Amendments to NERC Rules of Procedure Appendices 3B and 3D	Appendices 3B and 3D		3/1/11	4/15/11	Yes 4/15/11
17.	Project 2010-15	Project 2010-15 - Urgent Action Revisions to CIP-005-3 - CIP-005	CIP-005		3/29/11	4/28/11	Yes 4/27/11
18.	Project 2009-06	Project 2009-06 - Facility Ratings - FAC-008 and FAC-009	FAC-008-3		3/17/11	5/2/11	Yes 5/2/11
19.	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	PRC-005-2		4/13/11	5/12/11	Yes 5/9/11
20.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System	BES Definition		4/28/11	5/27/11	Yes 5/27/11
21.	Project 2006-02	Project 2006-02 - Assess Transmission and Future Needs	TPL-001-2		4/18/11	5/31/11	Yes 5/31/11
22.	Project 2007-03	Project 2007-03 - Real-time Operations - TOP-001 through TOP-008 and PER-001	TOP-001 through TOP-008 and PER-001		4/26/11	6/9/11	Yes 6/9/11
23.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System	BES Definition		5/11/11	6/10/11	Yes 6/10/11
24.	NERC RoP	Rules of Procedure Development Team: BES Definition Exception Process	BES Definition Exception Process		5/11/11	6/10/11	Yes 6/10/11

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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	
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

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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
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

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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	
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

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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	
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	

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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
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

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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
			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

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88.	Project 2007-12	Project 2007-12 Frequency Response Technical Conferences			5/30/12	6/15/12	
89.	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-003	COM-003		5/7/12	6/20/12	Yes 6/20/12
90.	N/A	Adequate Level of Reliability Revised Definition and Associated Documents	Adequate Level of Reliability (ALR)		4/25/12	6/25/12	Yes 6/25/12
91.	N/A	Order 754 - Request for Data or Information	Data Request		5/11/12	6/25/12	Yes 6/25/12
92.	Project 2011-INT-02	Project 2011-INT-02 - Interpretation of VAR -002 for Constellation	Interpretation of VAR -002		5/22/12	6/27/12	Yes 6/27/12
93.	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	PRC-005-2		5/29/12	6/27/12	Yes 6/27/12
94.	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserve	BAL-001-1		6/4/12	7/3/12	Yes 7/3/12
			BAL-002-2		6/4/12	7/3/12	Yes 7/3/12
			BAL-012-1		6/4/12	7/3/12	Yes 7/3/12
			BAL-013-1		6/4/12	7/3/12	Yes 7/3/12
95.	Project 2007-06	Project 2007-06 - System Protection Coordination	PRC-001 and PRC-027		5/21/12	7/5/12	Yes 7/5/12
96.	N/A	Cost Effective Analysis Process (CEAP) for NERC ERO Standards	CEAP		5/7/12	7/6/12	Yes 7/6/12
97.	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001, COM-002 and IRO-001-3	COM-001, COM-002 and IRO-001-3		6/7/12	7/6/12	Yes 7/6/12
98.	Project 2006-02	Project 2006-02 – Assess Transmission Future Needs and Develop Transmission Plans	TPL-002-1b, footnote ‘b’ and TPL-001-3, footnote 12		6/19/12	7/9/12	Yes 7/9/12

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99.	N/A	Standard Processes Manual Revisions to Implement SPIG Recommendations	SPIG Reco		6/20/12	7/19/12	Yes 7/19/12
100.	Project 2012-INT-02	Project 2012-INT-02 - Interpretation of TPL-003-0a and TPL-004-0 for System Protection and Control Subcommittee	- Interpretation of TPL-003-0a and TPL-004-0		6/20/12	7/20/12	Yes 7/19/12
101.	Project 2012-INT-05	Interpretation of 2012-INT-05 - Interpretation of CIP-002-3 for OGE	Interpretation of CIP-002-3		6/27/12	7/27/12	Yes 7/27/12
102.	Project 2011-INT-02	Project 2011-INT-02 - Rapid Revision to Address Interpretation of VAR-002 for Constellation	Rapid Revision to VAR-002		7/18/12	7/27/12	Yes 7/26/12
103.	Project 2010-INT-01	Project 2010-INT-01 - Rapid Revision of TOP-006 for FMPP	Rapid Revision of TOP-006		6/14/12	7/30/12	Yes 7/27/12
104.	Project 2012-08.1	Project 2012-08.1 - Phase 1 of Glossary Updates: Statutory Definitions	Glossary of Terms		6/19/12	8/2/12	Yes 8/2/12
105.	N/A	Reliability Guideline: System Operator Verbal Communications – Current Industry Practices	System Operator Verbal Communications		6/26/12	8/10/12	Yes 8/9/12
106.	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	PRC-005-2		7/27/12	8/27/12	Yes 8/27/12
107.	Project 2010-11	Project 2010-11 - TPL Table 1 Order TPL-002-1b, footnote ‘b’ and TPL-001-3, footnote 12	TPL-002-1b, footnote ‘b’ and TPL-001-3, footnote 12		7/31/12	8/29/12	Yes 8/29/12
108.	Project 2006-02	Project 2006-02 - Assess Transmission and Future Needs			7/31/12	8/30/12	
109.	Project 2009-19	Project 2009-19 – Interpretation of BAL-002 by NWPP Reserve Sharing Group			7/25/12	9/4/12	

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110.	Project 2013-02	Project 2013-02 - Paragraph 81	Paragraph 81		8/3/12	9/4/12	Yes 9/4/12
111.	Project 2010-05.1	Project 2010-05.1 - Protection Systems: Phase 1 (Misoperations)			7/25/12	9/7/12	Yes 9/7/12
112.	N/A	Definition of Adequate Level of Reliability	Adequate Level of Reliability (ALR)		8/15/12	9/13/12	Yes 9/13/12
113.	N/A	2013-2015 Reliability Standards Development Plan	2013-2015 RSDP		8/17/12	9/18/12	Yes 9/18/12
114.	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols	COM-003-1		8/22/12	9/20/12	Yes 9/20/12
115.	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting	EOP-004-2		8/29/12	9/27/12	
116.	SPP Regional Standard	Regional Reliability Standard PRC-006-SPP-01 Automatic Underfrequency Load Shedding	PRC-006-SPP-01		8/15/12	9/28/12	
117.	Project 2008-06 Project 2008-06	Project 2008-06 - Cyber Security - Order 706 - CIP-002-5 through CIP-009-5, CIP-010-1, and CIP-011-1	Version 5 CIP Standards		9/11/12	10/10/12	Yes 10/10/12
			RSAW		9/11/12	10/10/12	Yes 10/10/12
118.	MRO SPM	Regional Reliability Standards - MRO Standards Process Manual			8/28/12	10/11/12	
119.	N/A	Standard Process Manual Revisions to Implement SPIG Recommendations	SPIG Reco		8/29/12	10/12/12	Yes 10/10/12
120.		Revisions to Outstanding VRFs and VSLs			9/5/12	10/19/12	
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	

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125.	Project 2008-06	Project 2008-06 - Cyber Security - Order 706 - CIP-002-5 through CIP-009-5, CIP-010-1, and CIP-011-1	Version 5 CIP Standards		10/26/12	11/7/12	
126.	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-025	PRC-025		10/5/12	11/7/12	
127.	N/A	IRO-006-WECC-2			10/3/12	11/16/12	
128.	Project 2010-11	Project 2010-11 - TPL Table 1, Footnote B			10/5/12	11/19/12	
129.	Project 2012-INT-02	Interpretation 2012-INT-02 - Interpretation of TPL-003-0a and TPL-004-0 for SPCS	Interpretation of TPL-003-0a and TPL-004-0		10/22/12	12/5/12	Yes 12/5/12
130.	Project 2013-02	Project 2013-02 - Paragraph 81	Paragraph 81		10/25/12	12/10/12	Yes 12/10/12
131.	Project 2012-INT-06	Project 2012-INT-06 - Interpretation of CIP-003-3 for Consumers Energy	- Interpretation of CIP-003-3		11/9/12	12/10/12	Yes 12/10/12
132.	Project 2012-INT-04	Project 2012-INT-04 - Interpretation of CIP-007-3 for ITC	- Interpretation of CIP-007-3		11/9/12	12/10/12	Yes 12/10/12
133.	Project 2007-02	Project 2007-02 - Operating Personnel Communication Protocols - RSAW	COM-003-1		11/14/12	12/13/12	Yes 12/13/12
			COM-003-1 RSAW		11/14/12	12/13/12	Yes 12/13/12
134.	Project 2007-06	Project 2007-06 - System Protection Coordination	PRC-001 and PRC-027		11/16/12	12/17/12	Yes 12/17/12
135.	Project 2012-INT-05	Project 2012-INT-05 - Interpretation of CIP-002-3 for OGE	Interpretation of CIP-002-3		11/6/12	12/20/12	Yes 12/20/12
136.	N/A	Standard Processes Manual to Implement SPIG Revisions	SPIG Reco		11/21/12	12/20/12	Yes 12/20/12
137.	Project 2010-11	Project 2010-11 - TPL Table 1, Footnote B	TPL-002-1b, footnote 'b' and TPL-001-3, footnote 12		12/10/12	1/11/13	Yes 1/11/13
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

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139.	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves - BAL-012-1	BAL-012-1		11/30/12	1/14/13	Yes 1/14/13
140.	N/A	Reliability Guideline--Draft Generating Unit Winter Weather Readiness - Current Industry Practices			12/20/12	2/4/13	Yes 2/4/13
141.	Project 2010-05-1	Project 2010-05-1 Protection System Misoperations					Yes 2/20/13
142.	Project 2007-09	Project 2007-09 Generator Verification - PRC-024-1	PRC-024-1	Formal	1/25/13	2/25/13	Yes 2/25/13
143.	N/A	Rapid Revision Procedure		Informal	2/25/13	3/6/13	Yes 3/6/13
144.	Project 2010-13-2	Project 2010-13-2 - Phase 2 of Relay Loadability - Generation - PRC-025-1	PRC-025-1	Formal	1/25/13	3/11/13	Yes 3/11/13
			Supplemental SAR	Informal	1/25/13	3/11/13	Yes 3/11/13
			Cost Effectiveness	CEAP Pilot	1/25/13	3/11/13	Yes 3/11/13
			RSAW	Feedback	1/25/13	3/11/13	Yes 3/11/13
145.	Project 2012-INT-04	Interpretation 2012-INT-04 - Interpretation of CIP-007 for ITC	Interpretation of CIP-007	Formal	2/6/13	3/22/13	Yes 3/22/13
146.	Project 2012-INT-06	Interpretation 2012-INT-06 - Interpretation of CIP-003 for Consumers Energy	Interpretation of CIP-003	Formal	2/6/13	3/22/13	Yes 3/22/13
147.	Project 2012-08-1	Project 2012-08-1 - Phase 1 of Glossary Updates--Statutory Definitions	Glossary of Terms	Formal	2/21/13	3/22/13	Yes 3/22/13
148.	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-003-1	COM-003-1	Formal	3/7/13	4/5/13	Yes 4/5/13
			RSAW	Feedback	3/7/13	4/5/13	Yes 4/5/13
149.	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves	BAL-001-2	Formal	3/12/13	4/25/13	Yes 4/25/13
			BAL-002-2	Formal	3/12/13	4/25/13	Yes 4/25/13
			BAL-013-1	Formal	3/12/13	4/25/13	Yes 4/25/13

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150.	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Reclosing Relays)	Draft SAR	Informal	4/5/13	5/6/13	Yes 5/6/13
			PRC-005-3	Formal	4/5/13	5/6/13	Yes 5/613
151.	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation	PRC-023-3 PRC-025-1	Formal	4/25/13	5/24/13	Yes 5/24/13
152.	Project 2007-11	Project 2007-11 - Disturbance Monitoring — PRC-002 and PRC-018	SAR	Informal	5/03/13	6/03/13	Yes 6/3/13
153.	Project 2007-11	Project 2007-11 - Disturbance Monitoring PRC-002 and PRC-018	Request for Information	Informal	6/05/13	7/05/13	
154.	Project 2007-06	Project 2007-06 - System Protection Coordination - PRC-001 and PRC-027	PRC-001 and PRC-027		6/04/13	7/03/13	Yes 7/03/13
155.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	BES Definition		5/29/13	7/12/13	Yes 7/12/13
156.	TRE Regional Standard	Regional Reliability Standard - BAL-001-TRE-01	BAL-001-TRE-01		5/31/13	7/15/13	
157.	N/A	NPCC Regional Standards Process Manual	NPCC RSPM		6/06/13	7/22/13	
158.	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-003	COM-003-1		6/20/13	7/19/13	Yes 7/19/13
159.	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-025	PRC-025-1		6/20/13	7/19/13	Yes 7/19/13
160.	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-023	PRC-023-3	Formal	6/20/13	8/05/13	Yes 8/5/13
161.	N/A	SPP RE Regional Standards Process Manual	SPP RSPM		6/26/13	8/09/13	
162.	Project 2013-03	Project 2013-03 - Geomagnetic Disturbance Mitigation	EOP-010-1	Formal	6/27/13	8/12/13	Yes 8/12/13

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163.	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Reclosing Relays) - PRC-005	PRC-005-3	Formal	7/10/13	8/23/13	Yes 8/23/13
164.	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards	INT-004-3 INT-006-4 INT-009-2 INT-010-2 INT-011-1	Informal	7/25/13	8/23/13	Yes 8/23/13
165.	Project 2012-05	Project 2012-05 ATC Revisions (MOD A) - MOD-001-2	MOD-001-2	Formal	7/11/13	8/26/13	Yes 8/26/13
166.	Project 2010-01	Project 2010-01 - Training - PER-005-2	PER-005-2	Formal	7/19/13	9/03/13	Yes 9/3/13
167.	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4, VAR-002-3	VAR-001-4 VAR-002-3	Formal	7/19/13	9/03/13	Yes 9/3/13
168	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-032-1, MOD-033-1	MOD-032-1 MOD-033-1	Formal	7/22/13	9/04/13	Yes 9/4/13
169.	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	MOD-031-1	Formal	7/22/13	9/04/13	Yes 9/4/13
170	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System – Phase 2	BES Definition Phase 2	Formal	8/6/13	9/4/13	Yes 9/4/13
171	Project 2012-13	Project 2012-13 - NUC Five-Year Review	NUC-001-2	5-year review	7/26/13	9/9/13	Yes 9/9/13
172	2014-2016 RSDP	2014-2016 Reliability Standards Development Plan	Reliability Standards Development Plan	Annual Review	8/30/13	9/13/13	Yes 9/13/13
173	Project 2010-02	Project 2010-02 Five-Year Review of FAC Standards	FAC-001-1 FAC-002-1	5-year review	8/1/13	9/16/13	Yes 9/16/13
174	Project 2010-02	Project 2010-02 Five-Year Review of FAC Standards	FAC-003-3 FAC-008-3 FAC-010-2.1 FAC-011-2 FAC-013-2 FAC-014-2	5-year review	8/1/13	9/16/13	Yes 9/16/13

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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
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

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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
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

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201	Project 2012-13	Project 2012-13 NUC-Nuclear Plant Interface Coordination Standard Authorization Request	NUC-001-2.1 SAR	Informal	2/12/14	3/13/14	Yes 3/13/14
202	Project 2010-05.2	Project 2010-05.2 Special Protection Systems (Phase 2 of Protection Systems) - SAR	SAR	Informal	2/18/14	3/19/14	Yes 3/19/14
203	Project 2014-03	Project 2014-03 - Revisions to TOP/IRO Reliability Standards	SAR	Formal	02/21/14	03/24/14	Yes 3/24/14
204	Project 2014-03	Technical Conferences on Revisions to TOP/IRO Reliability Standards	Technical Conference Topics	Informal	03/11/14	03/24/14	
205	Project 2014-04	Project 2014-04 - Physical Security	SAR	Informal	03/21/14	03/28/14	Yes 3/28/14
206	Project 2010-14.2	Project 2010-14.2 - Periodic Review of BAL Standards	Reco to Revise BAL-005 and BAL-006	Formal	02/21/14	04/07/14	
207	2010-05.2	Project 2010-05.2 - Phase 2 of Protection Systems - Revised Definition of Special Protection System	SPS Definition	Informal	03/11/14	04/09/14	Yes 4/9/14
208	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	MOD-031-1	Formal	02/25/14	04/10/14	Yes 4/10/14
209	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4, VAR-002-3	VAR-002-3	Formal	02/27/14	04/14/14	Yes 4/14/14
210	Project 2008-02	Project 2008-02 - Undervoltage Load Shedding - PRC-010, PRC-020, PRC-021 and PRC-022	PRC-010-1	Informal	03/17/14	04/16/14	Yes 4/16/14
211	Project 2014-04	Project 2014-04 Physical Security - CIP-014-1	CIP-014-1	Formal	04/10/14	04/24/14	Yes 4/24/14
212	Project 2009-03	Project 2009-03 Emergency Operations – EOP-011-1	EOP-011-1	Informal	03/28/14	04/28/14	Yes 4/28/14

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213	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	PRC-005-2(X) PRC-005-3(X) PRC-005-X(X) VAR-002-2b(X) VAR-002-4	Formal	04/17/14	05/05/14	Yes 5/5/14
214	Project 2010-02	Project 2010-02 – Connecting New Facilities to the Grid	FAC-001-1 FAC-002-1	Formal	04/01/14	05/15/14	Yes 5/15/14
215	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation	TPL-007-1	Informal	04/22/14	05/21/14	Yes 5/21/14
216	Project 2012-13	Project 2012-13 Nuclear Plant Interface Coordination	NUC-001-3	Formal	04/08/14	05/22/14	Yes 5/22/14
217	Project 2007-17.3	Project 2007-17.3 Protection System Maintenance and Testing – Phase 3 (Sudden Pressure Relays)	PRC-005-X	Formal	04/17/14	06/03/14	Yes 6/3/14
218	Project 2010-13.3	Project 2010-13.3 Relay Loadability: Stable Power Swings	PRC-026-1	Formal	04/25/14	06/09/14	Yes 6/9/14
219	Project 2007-11	Project 2007-11 Disturbance Monitoring	PRC-002-2	Formal	05/09/14	06/25/14	Yes 6/25/14
221	Project 2008-02	Project 2008-02 Undervoltage Load Shedding and Underfrequency Load Shedding	PRC-010 PRC-020 PRC-021 PRC-022	Informal	05/23/14	06/23/14	Yes 6/23/14
222	Project 2010-05-1	Project 2010-05-1 Protection System – Phase 1 – Misoperations	PRC-004	Formal	05/16/14	07/09/14	Yes 7/9/14
223	Project 2014-03	Project 2014-03 Revisions to TOP-IRO Reliability Standards	TOP-001-3 TOP-002-4 TOP-003-3 IRO-001-4 IRO-002-4 IRO-008-2 IRO-010-2 IRO-014-3 IRO-017-1	Formal	05/19/14	07/02/14	Yes 7/2/14
224	Project 2014-02	Project 2014-02 CIP Version 5 Revisions	CIP-002 to CIP-011	Formal	06/02/14	07/17/14	Yes 7/16/14

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		– Cyber Security Standards					
225	Project 2015-2017	Project 2015-2017 Reliability Standard Development Plan		Informal		7/21/14	Yes 7/21/14
226	2010-05.2	Project 2010-05.2 - Phase 2 of Protection Systems - Revised Definition of Special Protection System	SPS Definition	Formal	7/16/14	7/25/14	Yes 7/25/14
227	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	PRC-005-2(X) PRC-005-3(X) PRC-005-X(X) VAR-002-2b(X) VAR-002-4	Formal	06/12/14	7/29/14	Yes 7/29/14
228	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation	TPL-007-1	Formal	06/13/14	07/30/14	Yes 7/30/14
229	Project 2008-02	Project 2008-02 Undervoltage Load Shedding and Underfrequency Load Shedding	PRC-010 PRC-020 PRC-021 PRC-022	Formal	06/23/14	08/8/14	Yes 8/6/14
230	Project 2010-14-2	Project 2010-14-2 Balancing Authority Reliability-based Control Standard Authorization Request for BAL-005 and BAL-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-	TOP-001-3 TOP-002-4	Formal	08/6/14	09/19/14	Yes 9/22/14

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		IRO Reliability Standards	TOP-003-3 IRO-001-4 IRO-002-4 IRO-008-2 IRO-010-2 IRO-014-3 IRO-017-1				
235	Project 2010-14.1	Project 2010-14.1 Balancing Authority Reliability-based Control	BAL-002-2	Formal	08/19/14	10/03/14	Yes 10/2/14
236	Project 2010-13.3	Project 2010-13.3 – Relay Loadability: Stable Power Swings	PRC-026-1	Formal	09/26/14	10/06/14	Yes 10/6/14
237	Project 2008-02	Project 2008-02: Underfrequency Load Shedding (UFLS)	PRC-006-2	Formal	08/21/14	10/08/14	Yes 10/7/14
238	Project 2013-03	Project 2013-03: Geomagnetic Disturbance Mitigation	TPL-007-1	Formal	08/27/14	10/10/14	Yes 10/10/14
239	NERC Rules of Procedure	NERC Rules of Procedure	NERC Rules of Procedure	Formal	08/26/14	10/10/14	Yes 10/14/14
240	Project 2010-05.2	Project 2010-05.2 – Special Protection Systems Phase 2 of Protection Systems	RAS Definition	Formal	08/29/14	10/14/14	Yes 10/14/14
241	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	VAR-002-2b(X) VAR-002-4	Formal	08/27/14	10/16/14	Yes 10/16/14
242	Project 2014-02	Project 2014-02 CIP Version 5 Revisions – Cyber Security Standards	CIP-003-6 CIP-010-2 CIP-003-X CIP-004-X CIP-007-X 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

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245	Project 2007-11	Project 2007-11 Disturbance Monitoring	PRC-002-2	Formal	09/05/14	10/21/14	Yes 10/21/14
246	Project 2014-01	Project 2014-01 Applicability for Dispersed Generation	PRC-004-2.1a(X) PRC-004-4	Formal	09/05/14	10/22/14	Yes 10/22/14
247	Project 2014-03	Project 2014-03 Revisions to TOP/IRO Reliability Standards TOP-001-3	TOP-001-3	Formal	10/10/14	11/10/14	Yes 11/10/14
248	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation TPL-007-1	TPL-007-1	Formal	10/28/14	11/21/14	Yes 11/24/14
249	Project 2010-13.3	Project 2010-13.3 – Relay Loadability: Stable Power Swings	PRC-026-1	Formal	11/04/14	11/24/14	Yes 11/25/14
250	Project 2014-01	Project 2014-01 – Standards Applicability for Dispersed Generation Resources	PRC-001-1.1 PRC-019-2 PRC-024-1	Formal	11/05/14	12/23/14	Yes 12/22/14
251	Project 2014-03	Project 2014-03 Revisions to TOP/IRO Reliability Standards TOP-001-3	TOP-001-3	Formal	12/29/14	1/7/15	Yes 1/6/15
252	Project 2014-02	Project 2014-02 CIP Version 5 Revisions	CIP-003-7 CIP-004-7 CIP-007-7 CIP-010-3 CIP-011-3 CIP-003-7 CIP-010-3 Implementation Plan	Formal	12/30/14	1/9/15	Yes 1/9/15
253	Project 2014-04	Project 2014-04 Physical Security SAR	SAR	Informal	12/15/14	1/13/15	Yes 1/12/15
254	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	White Paper Appendix A Appendix B	Informal	12/22/14	1/20/15	Yes 1/20/15
255	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed	PRC-005-5	Informal	12/22/14	1/20/15	Yes 1/22/15

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		Generation Resources					
257	Project 2010-14.1	Project 2010-14.1 Balancing Authority Reliability-based Control	BAL-002-2	Formal	1/29/15	3/18/15	Yes 3/16/15
258	Reliability Guideline	Reliability Guideline: Loss of Real-Time Reliability Tools Capability/Loss of Equipment Significantly Affecting ICCP Data		Formal	2/19/15	4/6/15	Yes 4/6/15
259	Project 2008-02.2	Project 2008-02.2 Phase 2 UVLS: Misoperation	PRC-010-2	Formal	2/20/15	4/7/15	Yes 4/7/15
260	Project 2014-04	Project 2014-04 Physical Security	CIP-014-2	Formal	2/20/15	4/9/15	Yes 4/9/15
261	Project 2015-04	Project 2015-04 Alignment of Terms	SAR	Formal	2/24/15	4/13/15	Yes 4/13/15
262	Project 2007-17.4	Project 2007-17.4 PRC-005 Order No. 803 Directives	SAR	Informal	3/12/15	4/10/15	Yes 4/13/15
263	Project 2015-06	Project 2015-06 Interconnection Reliability Operations and Coordination	SAR	Informal	3/16/15	4//15/15	Yes 4/15/15
264	Project 2010-14.2.2	Project 2010-14.2.2 Phase 2 of Balancing Authority Reliability-based Controls: Time Error Correction	SAR	Informal	3/17/15	4//15/15	Yes 4/15/15
265	Project 2015-02	Project 2015-02 Periodic Review of Emergency Operations	EOP-008-1	Informal	3/27/15	5/11/15	Yes 5/11/15
266	Project 2015-02	Project 2015-02 Periodic Review of Emergency Operations	EOP-006-2	Informal	3/27/15	5/11/15	Yes 5/11/15
267	Project 2015-02	Project 2015-02 Periodic Review of Emergency Operations	EOP-005-2	Informal	3/27/15	5/11/15	Yes 5/11/15
268	Project 2015-02	Project 2015-02 Periodic Review of Emergency Operations	EOP-004-2	Informal	3/27/15	5/11/15	Yes 5/11/15

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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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-based Controls	BAL-002-2	Formal	7/7/15	8/20/15	Yes 8/20/15
282	Project 2010-	Phase 2 of Balancing Authority	BAL-004-0	Survey	8/12/15	8/25/15	Yes 8/25/15

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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
	14.2.2	Reliability-based Controls: Time Error Correction					
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

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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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 2016-02	Modifications to CIP Standards	SAR	Informal	3/23/16	4/21/16	Yes 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	Emergency	EOP-004-4	Formal	7/25/16	9/8/16	Yes 9/8/16

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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
	2015-08	Operations					
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 2016-02	Modifications of CIP Standards	CIP-003-TCA	Informal	11/1/16	11/18/16	Yes 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	SPM	Formal	3/20/17	5/3/17	Yes 5/3/17

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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
		Processes Manual					
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
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
351	Project 2015-10	Single Points of Failure	TPL-001-5	Formal	9/8/17	10/23/17	Yes 10/23/17
352	Project 2016-02	Modifications to CIP Standard	CIP-002-6	Formal	9/14/17	10/30/17	Yes 10/30/17
353	Project 2015-09	Establish and Communicate System Operating Limits	Proposed Definitions of System Operating Limit (SOL) and SOL Exceedance	Informal	9/29/17	10/30/17	Yes 10/30/17
354	Project 2016-02	Modifications to CIP Standard	Virtualization	Informal	10/6/17	11/2/17	Yes 11/2/17
355	Project 2015-09	Establish and Communicate System Operating	FAC-010 FAC-011 FAC-014	Formal	9/29/17	11/13/17	Yes 11/13/17

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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
		Limits					
356	Project 2017-01	Modifications to BAL-003-1.1	SAR	Formal	11/2/17	12/1/17	Yes 12/1/17
357	Project 2016-02	Modifications to CIP Standard	CIP-012-1	Formal	10/27/17	12/11/17	Yes 12/11/17
358	Project 2016-02	Modifications to CIP Standard	Technical Rationale/Justification	Informal	11/20/17	12/11/17	Yes 12/11/17
359	Project 2017-03	FAC-008-3 Periodic Review	FAC-008-3	Formal	10/30/17	12/13/17	Yes 12/13/17
360	Project 2016-04	Modifications to PRC-025-1	PRC-025-1	Formal	10/30/17	12/13/17	Yes 12/13/17
361	Project 2017-07	Alignment with Registration	SAR	Formal	12/11/17	1/9/18	Yes 1/9/18
362	Project 2017-05	NUC-001-3	NUC-001-3	Formal	12/15/17	1/29/18	Yes 1/29/18
363	Project 2017-04	INT Periodic Review	INT-004-3.1 INT-006-4 INT-009-2.1 INT-010-2.1	Formal	1/10/18	2/23/18	Yes 2/23/18
364	Project 2017-07	Standards Alignment with Registration	Multiple Standards	Formal	2/1/18	3/2/18	Yes 3/2/18
365	Project 2017-02	Modifications to Personnel Performance, Training and Qualifications (PER) Standards	PER-003-1 PER-004-2	Formal	1/22/18	3/7/18	Yes 3/7/18
366	Project 2015-10	Single Points of Failure	TPL-001-5	Formal	2/23/18	4/23/18	Yes 4/23/18
367	Project 2018-01	Canadian-specific Revisions to TPL-007-2 SAR	TPL-007-2 SAR	Formal	3/30/18	4/30/18	Yes 4/30/18
368	Project 2016-02	Modifications to CIP Standard	CIP-002-6	Formal	3/16/18	4/30/18	Yes 4/30/18
369	Project 2016-02	Modifications to CIP Standard	CIP-012-1	Formal	3/16/18	4/30/18	Yes 4/30/18
370	Project 2016-02	Modifications to CIP Standard	Control Center Definition and Implementation	Formal	3/16/18	4/30/18	Yes 4/30/18
371	Standards Grading	2018 Periodic Review Standing Review Team	Standard Grading	Informal	5/14/18	6/28/18	Yes 6/28/18
372	Project 2016-02	Modifications to CIP Standard	CIP-012-1	Formal	5/18/18	7/3/18	Yes 7/2/18
373	SER	Standard Efficiency Review	SAR	Informal	6/7/18	7/10/18	Yes 7/10/18
374	Project 2016-02	Modifications to CIP Standard	CIP-002-5.1a SAR	Informal	6/14/18	7/13/18	Yes 7/13/18
375	Project 2016-02	Modifications to CIP Standard	CIP-003-7 SAR Order 843	Informal	6/14/18	7/13/18	Yes 7/13/18
376	SPM	Standards Processes Manual	SPM	Formal	6/25/18	8/9/18	Yes 8/9/18

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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
377	Project 2018-01	Canadian-specific Revisions to TPL-007-2	TPL-007-2	Informal	8/10/18	9/6/18	Yes 9/6/18
378	Project 2018-02	Modifications to CIP-008 Cyber Security Incident Reporting SAR	CIP-008-5	Informal	8/10/18	9/10/18	Yes 9/10/18
379	Project 2015-10	Single Points of Failure	TPL-001-5	Formal	7/30/18	9/14/18	Yes 9/14/18
380	Functional Model Advisory Group	Functional Model Advisory Group	Functional Model Advisory Group	Informal	8/3/18	9/19/18	Yes 9/17/18
381	Project 2017-01	Modifications to BAL-003-1.1	BAL-003-1.1	Informal	9/6/18	9/20/18	Yes 9/20/18
382	SER	Standard Efficiency Review	SAR	Formal	8/28/18	9/26/18	Yes 9/26/18
383	Project 2016-02	Modifications to CIP Standards	CIP-002-6	Formal	8/23/18	10/9/18	Yes 10/9/18
384	Project 2016-02	Modifications to CIP Standards	CIP-003-8	Formal	8/23/18	10/9/18	Yes 10/9/18
385	Project 2015-09	Establish and Communicate System Operating Limits	FAC-010 FAC-011 FAC-014	Formal	8/24/18	10/17/18	Yes 10/17/18
386	Project 2018-02	Cyber Security – Incident Reporting and Response Planning	CIP-008-6	Formal	10/3/18	10/22/18	Yes 10/22/18
387	Project 2018-01	Canadian-specific Revisions to TPL-007-2	TPL-007-2	Formal	10/2/18	11/15/18	Yes 11/15/18
388	Project 2018-02	Cyber Security – Incident Reporting and Response Planning	CIP-008-6	Formal	11/15/18	11/29/18	Yes 11/29/18
389	Project 2016-02	Modifications to CIP Standards	Virtualization	Informal	11/2/18	12/18/18	Yes 12/18/18
390	Project 2017-01	Modifications to BAL-003-1.1	BAL-003-1.1	Formal	12/4/18	1/17/19	Yes 1/17/19
391	Project 2018-04	Modifications to PRC-024-2	PRC-024-2	Formal	12/19/18	1/18/19	Yes 1/18/19
392	Standard Efficiency Review	Standard Efficiency Review	SER Phase 2 Concepts Survey	Informal	2/22/19	3/22/19	Yes 3/22/19
393	Project 2019-01	Modifications to TPL-007-3	TPL-007-3	Informal	2/25/19	3/26/19	Yes 3/26/19
394	Project 2018-03	Standard Efficiency Review Retirements	FAC-008-4 INT-006-5 INT-009-3 IRO-002-6 PRC-004-6 TOP-001-5	Formal	2/27/19	4/12/19	Yes 4/12/19

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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
			VAR-001-6 FAC-013-2 INT-004-3.1 INT-010-2.1 MOD-001-1a MOD-004-1 MOD-008-1 MOD-020-0 MOD-028-2 MOD-029-2a MOD-030-3 MOD-001-2				
395	Project 2019-02	BES Cyber System Information Access Management	CIP-004-6	Formal	3/28/19	4/26/19	Yes 4/26/19

Note: RSC past comment forms are posted on the NPCC Website under "Standards - Regional Standards Comments."

NPCC, Inc.

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

February 15th, 2019

NPCC Full and General Members:

In accordance with the FERC approved NPCC Regional Standard Processes Manual, revisions were performed for the NPCC Regional Standard PRC-006-NPCC-02 Automatic Underfrequency Load Shedding. The Standard was posted for three open process comment periods and a pre-ballot review. A ballot was then conducted which closed at 23:59PM on February 10th, 2019.

The results of the ballot were as follows:

Quorum: 80.95% of the Total Registered NPCC General and Full Members Representatives
Approval: 76%

Requisite approval was attained for the ballot therefore a recommendation for final NPCC Regional approval will be sent to the NPCC Board of Directors for consideration at their meeting on May 1st, 2019.

Contingent upon the approval of the NPCC BOD, the proposal to approve PRC-006-NPCC-02 will be submitted to the NERC Board of Trustees for their consideration and adoption at their August 14-15, 2019 meeting. NERC and NPCC will then develop filings for the FERC and applicable provincial authorities for their review and final approval.

Voting was conducted electronically and the full record for the standard may be viewed, after signing in, at:

https://www.npcc.org/Standards/SitePages/DevStandardDetail.aspx?DevDocumentId=122

Thank you for your participation in the development of this important Standard to ensure the reliablity objectives of NPCC.

Ruida Shu
Northeast Power Coordinating Council, Inc.
Manager, Reliability Standards
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	**17**	**17**	**0**		**17**	**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	1			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 Hampshire Transmission, LLC	1	1			1		
New York Power Authority	1	1			1		
New York State Electric & Gas Corporation	1	1			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	**21**	**17**	**2**	**19**	**0**	**0**
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 Brunswick Power Corporation	1	1		1		
New York Power Authority	1	1		1		
Orange and Rockland Utilities, Inc	1	1		1		
Princeton Municipal Light Department	1					
Shrewsbury Electric & Cable Operations	1	1		1		
Sterling Municipal Light Department	1	1		1		
Toronto Hydro Electric System Ltd.	1	1		1		
Vermont Electric Cooperative, Inc.	1					
Wakefield Municipal Gas and Light Department	1	1		1		
Westfield Gas & Electric	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 4, Generator Owners	**20**	**16**	**0**		**10**	**4**	**2**
Bruce Power L.P.	1						
Consolidated Edison Company of New York, Inc.	1	1			1		
Covanta Energy	1	1				1	
Dominion Resources, Inc.	1	1			1		
Eastern Generation LLC	1	1					1
Entergy Nuclear Northeast, Inc	1	1			1		
Exelon Generation Company, LLC	1						
First Wind Operations & Maintenance	1						
Long Island Power Authority	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	1				1	
Talen Energy Supply, LLC	1	1				1	
TransCanada	1	1			1		
Vistra Energy Corp	1	1			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	**12**	**9**	**0**		**8**	**0**	**1**
Brookfield Power Corporation	1	1			1		
Consolidated Edison Company of New York, Inc.	1	1			1		
Consolidated Edison Energy/Development	1						
HQ Energy Marketing Inc.	1	1			1		
H.Q. Energy Services (U.S.) Inc.	1	1			1		
Long Island Power Authority	1	1			1		
Massachusetts Municipal Wholesale Electric Company	1	1			1		
Nalcor Energy	1						
New York Power Authority	1	1			1		
Nexus Energy Inc.	1	1					1
Shell Energy North America	1						
Utility Services Inc.	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 6, State and Provincial Reg. and Govt. Au	**5**	**3**	**0**		**3**	**0**	**0**
Long Island Power Authority	1	1			1		
Maine Public Utilities Commission	1	1			1		
New Hampshire Public Utilities Commission	1						
New York Power Authority	1	1			1		
New York State 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	**25**	**16**	**0**		**14**	**0**	**2**
4g Technologies, LP	1						
Abloy Security, Inc.	1	1			1		
AESI Acumen Engineered Solutions Internaiontal Inc.	1	1			1		
Ascendant Energy Solutions, Inc.	1						
Casimir Systemics LLC	1	1			1		
Ciufo & Cooperberg Consulting Inc.	1	1			1		
DataCapable, Inc.	1						
David Kiguel	1	1			1		
ERLPhase Power Technologies	1	1			1		
GDS Associateds, Inc.	1	1			1		
Genieall	1						
International Business Machines Corporation	1						
Ironhouse Inc.	1						
McCoy Power Consultants, Inc.	1	1			1		
Network & Security Technologies, Inc.	1	1					1
New Power Technologies, Inc	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		
Sund Technologies, LLC	1						
TRC Solutions	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**	17	17	0	17	1.00
2	**Reliability Coordinators**	5	5	0	5	1.00
3	**TDUs, Dist. And LSE**	21	17	2	19	0.90
4	**Generator Owners**	20	16	0	16	0.80
5	**Marketers, Brokers, Aggragators**	12	9	0	9	0.75
6	**Customers- large and small**	5	3	0	3	0.60
7	**State and Provincial Reg. and Govt. Authorities**	25	16	0	16	0.64
		105	83	2	85	

Electronic Vote Quorum= at least 2/3 of the Total Registered

Quorum Present? **YES**

Determine if Motion or Item Passes

Sector	Sector Name	Total Registered	Sector % Attending	Affirmative # of Votes	Affirmative Fraction	Negative # of Votes	Negative Fraction	Abstain # of Votes	Votes Cast Total (-Abstentions)	Sector has Voted(1-Y, 0-N)
1	**Transmission Owners**	17	1.00	17	1.000	0	0.000	0	17	1
2	**Reliability Coordinators**	5	1.00	5	1.000	0	0.000	0	5	1
3	**TDUs, Dist. And LSE**	21	0.90	19	1.000	0	0.000	0	19	1
4	**Generator Owners**	20	0.80	10	0.714	4	0.286	2	14	1
5	**Marketers, Brokers, Aggragators**	12	0.75	8	1.000	0	0.000	1	8	1
6	**Customers- large and small**	5	0.60	3	1.000	0	0.000	0	3	1
7	**State and Provincial Reg. and Govt. Authorities**	25	0.64	14	1.000	0	0.000	2	14	1
	Totals	105		76	6.714	4	0.286	5	80	7

Sum of Affirmative/Number of Sectors that Voted MUST BE AT LEAST 2/3 to pass 0.959

Did MOTION PASS? PASS

May xx, 2019

The Regional Standards Committee (RSC) Response to Comments Received in the Open Process Posting of the revised Directory Development and Revision Manual.

The RSC would like to thank those who provided comments on the proposed revisions to the NPCC Directory Development and Revision Manual which was posted from January 4, 2019 to February 18, 2019. The RSC responses to individual comments are provided below.

Comments from New Brunswick Power:

After a review of the proposed changes to the NPCC Directory Development and Revision Manual ("the Directory Manual") NBP has the following comments/recommendations.

Note that the comments extend beyond the Cost Effectiveness Analysis (CEA) process revisions.

Comment 1:

Suggest Modifying Directory/Criteria balloting process.

Consider modifying language in the Directory Manual such that the RCC does not approve Directories/Criteria in advance of balloting, but rather the RCC simply recommends that Directory/Criteria go to ballot.

With the present practice of the RCC approving a Directory prior to balloting, NPCC Members are losing an important opportunity to have the Directory vetted through the balloting process. Negative voting on a Directory should not be perceived as opposing the RCC initial approval, but rather seen as an opportunity to improve the Directory.

Rather than RCC approval prior to ballot, suggest that the RCC recommend for ballot based on stability in the development/revision phase (commenting/modifications not resulting in additional material changes) as well as meeting the intended reliability objective.

While this comment is not directly related to the CEA revisions being proposed, it should see a more rigorous review of Directories including CEA reviews during the development process.

RSC Response:

Comment 2:

Suggest adding guidance to tailor criteria based on CEA results.

Aspects of a proposed Directory may not be equally cost effective across the region or across all BPS facilities. Instead of simply seeking a "one size fits all" solution which may result in unnecessary added expense or abandoning a proposed Directory's reliability benefit, consider providing guidance on the CEA review to allow further refinement.

Suggested change in the text of VIII (5) below:

5. The Task Force shall use the information obtained, to make a determination if the revised or new Criteria is of sufficient reliability benefit to pursue further development activities by NPCC. If the benefit is prevalent to particular local areas, specific configurations or situations, consider tailoring the criteria applicability accordingly. Otherwise other cost effective approaches to achieve the reliability objective of the Criteria should be pursued. (E.g. development of a whitepaper, guideline document, etc.)

RSC Response:

Comment 3:

Suggest requiring approval when waiving CEA.

In looking at page 9 and 21: Suggest adding the text highlighted below to ensure that waiving the CEA process is approved.

1) Section VIII provides guidance for the CEA and Open Process posting. If the Lead Task Force determines that there is no benefit to conducting the CEA activity then this decision shall be documented and notification provided to the RCC and RSC along with the reasons for the decision to waive this portion of the process. The RCC may accept the Lead Task Force determination not to proceed with a CEA or request that a CEA be completed.

2) The Lead Task Force will document these activities as part of the record of development and notify the RCC and RSC of intent to conduct cost effectiveness analysis or exercise a waiver. The waiver will be subject to RCC approval.

RSC Response:

Comment 4:

Clarify Functional Entity Applicability

The applicability section of each Directory identifies those Functional Entities that are assigned reliability requirements. The Functional Entities appear to be based on the NERC functional model. While the NERC functional model has clear processes to identify and inform on applicability of NERC standards, there does not appear to be any process that aligns NPCC voluntary membership with the Functional Entities listed in the Directories.

A recommendation is to utilize the NPCC Full Member Sector Membership as the basis for determining Functional Entity.

Suggest including the wording in section III as follows:

III. APPLICABILITY OF NPCC CRITERIA

The requirements of an NPCC Directory apply only to those Full Member facilities defined as NPCC bulk power system elements as identified through the performance based methodology of NPCC Document A-10, "Classification of Bulk Power System Elements," the current list of which is maintained by the NPCC Task Force on System Studies and approved by the NPCC Reliability Coordinating Committee. For entities that may qualify for multiple Full Memberships, Full Membership sector representation will be the basis for determining Functional Entity applicability as listed in the Directory.

RSC Response:

Comment 5:

Comment on Generator Applicability

The Directories and the Directory manual identify generator applicability as only those BPS elements identified by the A-10 methodology. However, there may be a belief that generator applicability is based on an MVA threshold.

RSC Response:

Comments from the New York State Reliability Council, LLC:

Comment 1:

Agree with changes.

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

March 29, 2019

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

Re: NERC Standards Report, Status and Timetable for Addressing Regulatory Directives
Docket No. RR09-6-003

Dear Secretary Bose:

The North American Electric Reliability Corporation ("NERC") hereby submits the 2019 NERC Standards Report, Status and Timetable for Addressing Regulatory Directives (the "Directives Report") in accordance with Section 321.6 of the NERC Rules of Procedure ("ROP").[1] This annual report summarizes the progress made, and plans for addressing the Reliability Standards-related directives issued by applicable governmental authorities.

Section 321.6 of NERC's ROP requires NERC, on or before March 31 of each year, to file a report with applicable governmental authorities on the status and timetable for addressing each outstanding regulatory directive.

As discussed in the attached Directives Report, since NERC's 2018 annual directives report filed on March 30, 2018, the Commission issued nine directives. In that time, NERC filed petitions with the Commission addressing ten directives.[2] Currently, there are 14 outstanding directives, eight of which NERC is addressing through existing standards development current projects. The other outstanding directives are not related to Reliability Standards development (i.e., the directives relate to data gathering, registration, or the performance of research/studies) and are being addressed through other mechanisms.[3]

The 2019-2021 Reliability Standards Development Plan ("RSDP") provides a plan to address the remainder of the standards-related directives. NERC's annual RSDP establishes priorities related to Reliability Standards to help ensure that those issues that most directly impact Bulk-Power System reliability are addressed first. Directives to create new or modify existing Reliability Standards are assigned to existing

[1] The Federal Energy Regulatory Commission ("FERC" or "Commission") approved Rule 321 on March 17, 2011 in the above captioned docket. *N. Am. Elec. Reliability Corp.*, *Order on Compliance Filing*, 134 FERC ¶ 61,216 (2011).

[2] *See* Directives Report at Chapter 2, Table 1 for a list of the directives that were addressed since April 1, 2018.

[3] *See* Directives Report at Chapter 2, Table 2 for a list of outstanding directives and status.

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or future development projects that are prioritized by the NERC Standards Committee and reflected in the RSDP. The 2019-2021 RSDP was filed with the Commission on December 14, 2018.[4]

In addition to the above information, NERC includes, as Appendix A to the Directives Report, NERC's Response to Directives on Vegetation Management on Federal Lands.

Please contact me if you have questions or need additional information.

Respectfully submitted,

/s/ Lauren A. Perotti
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Enclosure:

2019 NERC Standards Report, Status and Timetable for Addressing Regulatory Directives

[4] NERC's 2019-2021 RSDP is accessible at the following link: https://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/2019-2021%20RSDP%20FERC%20Filing.pdf.

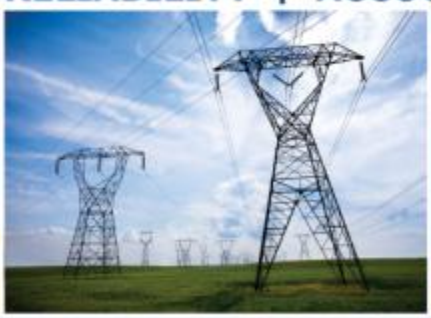
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

NERC Standards Report

Status and Timetable for Processing Regulatory Directives

March 29, 2019

RELIABILITY | ACCOUNTABILITY



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Chapter 1 – Introduction

In accordance with Section 321.6 of the North American Electric Reliability Corporation ("NERC") Rules of Procedure ("ROP"),[1] this report provides an update on the status and timetable for addressing outstanding directives issued by the Federal Energy Regulatory Commission ("FERC" or "Commission").[2]

As discussed below, since NERC's 2018 annual directives report filed on March 30, 2018, the Commission has issued nine directives.[3] As detailed in Table 1 below, NERC has also filed petitions with the Commission addressing ten directives. Currently, there are 14 outstanding directives listed in Table 2, eight of which NERC is addressing through existing standards development current projects. The other outstanding directives are not related to Reliability Standards development (i.e., the directive relates to data gathering, registration, or the performance of research/studies) and being addressed through other mechanisms.

NERC's 2019-2021 Reliability Standards Development Plan ("RSDP") provides a plan to address the outstanding Reliability Standards-related directives. NERC's annual RSDP establishes priorities related to Reliability Standards to help ensure that those issues that most directly impact Bulk-Power System reliability are addressed first. Directives to create new or modify existing Reliability Standards are assigned to existing or future development projects that are prioritized by the NERC Standards Committee and reflected in the RSDP. The 2019-2021 RSDP was filed with the Commission on December 14, 2018.[4]

[1] Section 321.6 of NERC's ROP requires NERC, on or before March 31 of each year, to file a report with applicable governmental authorities on the status and timetable for addressing each outstanding regulatory directive.

[2] This report includes both Reliability Standard-related directives and non-Reliability Standard-related directives (i.e., directives that pertain to information or data collection as opposed to the development of new or modified Reliability Standards). Prior to the 2017 annual directives report, non-Reliability Standard directives were not included in the annual report.

[3] These directives consist of: two directives related to Cyber Security Incident Reporting; two directives relating to the CIP-003 Reliability Standard; two directives related to the Supply Chain Reliability Standards; and three directives related to the TPL-007 Reliability Standard.

[4] NERC's 2018-2020 RSDP was filed in Docket Nos. RM05-17-000, RM-05-25-000, and RM06-16-000 and is available on NERC's website at: https://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/2019-2021%20RSDP%20FERC%20Filing.pdf.

Chapter 2 – Status of Directives

The two tables below contain a status update on the directives. Table 1 contains a complete list of the directives NERC addressed since the 2018 directives report. Table 2 provides a list of the outstanding directives and an update on NERC's plans to address those directives.

Table 1: Directives Addressed since April 1, 2018

Directive Summary	Action Taken	Project Name	Filing Date
Order on GMD Work Plan at P 9[5] - FERC "directs NERC to file for Commission review a final, or otherwise updated, GMD Work Plan within six months of the date of this order."	GMD Work Plan was filed.	N/A	4/19/2018
S-Ref 10912 (Order No. 794 at P 34[6]) - The Commission "directs NERC to continue its evaluation of the use of the linear regression methodology based upon experience and data collected following the implementation of BAL-003-1 and to submit a report to the Commission within three months after two years of operating experience once Requirement R1 of BAL-003-1 becomes effective (i.e., 27 months from the effective date of Requirement R1). The report should assess the accuracy of the linear regression methodology compared to the median methodology for purposes of determining Frequency Response Measure. Based on this report and actual experience, the Commission may revisit this issue."	Report was drafted and filed.	N/A	6/29/2018 and supplemented on 8/7/2018
S-Ref 10913 (Order No. 794 at P 60) - "The Commission adopts the NOPR proposal and directs NERC to submit a report that provides an analysis of the availability of resources for each balancing authority and Frequency Response Sharing Group to meet its Frequency Response Obligation during the first year of implementation. However, NERC indicates in its comments that it needs more than the proposed 15 months to prepare the report based on the time frame for NERC to receive relevant data from applicable entities. Accordingly, we direct NERC to submit this report within 27 months of implementation of Requirement R1." Order No. 794 at P 60 - "Further, consistent with NERC's representation in its comments, the Commission directs that, upon completion of the required analysis, should the findings indicate that the Frequency Response Obligation was not met, NERC shall provide appropriate recommendations to ensure that frequency response can be maintained at all times within each balancing authority's footprint."	Report was drafted and filed.	N/A	6/29/2018 and supplemented on 8/7/2018

[5] *Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events, Order on GMD Research Work Plan*, 161 FERC ¶ 61,048 (2017).

[6] *Frequency Response and Frequency Bias Setting Reliability Standard*, 146 FERC ¶ 61,024 (2014) ("Order No. 794").

Directive Summary	Action Taken	Project Name	Filing Date
S-ref10953 (Order No. 835 at P 23[7]) - "[W]e direct NERC to develop modifications to Reliability Standard BAL-002-2 to address our concerns, discussed below, regarding the 15-minute ACE recovery period set forth in Requirement R1." Order No. 835 at P 37 - "[W]e direct NERC to develop modifications to Reliability Standard BAL-002-2, Requirement R1 to require balancing authorities or reserve sharing groups: (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."	Standard was modified.	Project 2017-06 Modifications to BAL-002-2	8/17/2018
S-Ref 10948 (Order No. 822 at P 53[8]) – "[W]e adopt the NOPR proposal and direct that NERC, pursuant to section 215(d)(5) of the FPA, develop modifications to the CIP Reliability Standards to require responsible entities to implement controls to protect, at a minimum, communication links and sensitive bulk electric system data communicated between bulk electric system Control Centers in a manner that is appropriately tailored to address the risks posed to the bulk electric system by the assets being protected (i.e., high, medium, or low impact)."	Standard was modified.	Project 2016-02 Modifications to CIP Standards	9/18/2018
S-Ref 10926 (Order No. 810 at P 2[9]) – "The Commission also directs NERC to submit an informational filing 90 days after the end of the two-year period following implementation that includes an analysis of data on whether experience with the Balancing Authority ACE Limit in the first two years after approval has seen ACE swings and inadvertent interchange and unscheduled power flows that could cause system operating limit (SOL) and interconnection reliability operating limit (IROL) exceedances. . . ." Order No. 810 at P 36 – "We determine that the field trial NERC conducted for Reliability Standard BAL-001-2 raised sufficient concerns regarding unscheduled power flows and inadvertent interchange to warrant NERC's continued monitoring and submission of an informational filing 90 days after the end of the two-year period following implementation, as proposed in the NOPR. Further, we find that the informational filing should encompass both the Western and Eastern Interconnections, as there were concerns about possible increases of SOL/IROL exceedances in both Interconnections."	Report was created and filed.	N/A	10/1/2018

[7] *Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event Reliability Standard*, 158 FERC ¶ 61,030 (2017) ("Order No. 835").

[8] *Revised Critical Infrastructure Protection Reliability Standards*, 154 FERC ¶ 61,037 (2016).

[9] *Real Power Balancing Control Performance Reliability Standard*, 151 FERC ¶ 61,048 (2015) ("Order No. 810").

Directive Summary	Action Taken	Project Name	Filing Date
S- Ref 10894 (Order No. 786 at P 40[10]) – "[We] direct 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."	Standard was modified.	Project 2015-10- Single Points of Failure	12/7/2018
S- Ref 10896 (Order No. 786 at P 89) –"[The Commission] directs NERC to consider a similar spare equipment strategy for stability analysis upon the next review cycle of Reliability Standard TPL-001-4."	Standard was modified.	Project 2015-10- Single Points of Failure	12/7/2018
Order No. 848 at P37[11] - "Therefore, pursuant to FPA section 215(d)(5), we direct NERC to develop and submit modifications to the Reliability Standards to include the mandatory reporting of Cyber Security Incidents that compromise, or attempt to compromise, a responsible entity's ESP or associated EACMS. As noted above, we direct NERC to submit the directed modifications within six-months of the effective date of this Final Rule."	Standard was modified.	Project 2018-02 Modifications to CIP-008 Cyber Security Incident Reporting	3/7/2019
S- Ref 10101 (Order No. 693 at P 732[12]) - "The Commission… directs the ERO to collect outage data for transmission outages of lines that cross both federal and non-federal lands, analyze it, and use the results of this analysis and information to develop a Reliability Standard that would apply to transmission lines crossing both federal and non-federal land." Order No. 777 at P 130[13] - "NERC should gather and analyze the necessary data regarding vegetation management issues on public lands. If NERC's analysis indicates that there are issues that should be addressed, NERC should propose a means to address the concern, for example by issuing an alert, or propose other appropriate action."	Data was collected and report is submitted as Appendix A to this filing.	N/A	3/29/2019

10 *Transmission Planning Reliability Standards,* 145 FERC ¶ 61,051 (2013) ("Order No. 786").

11 *Cyber Security Incident Reporting Reliability Standards*, 164 FERC ¶ 61,033 (2018).

12 *Mandatory Reliability Standards for the Bulk-Power System*, 118 FERC ¶ 61,218 (2007)

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

Table 2: Status of Outstanding Directives								
Directive Summary	**Owner**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Project Number**	**Project Name**	**Status**
S-Ref 10917 – "Accordingly, should NERC make changes to Table 1 based upon NERC's Procedure document, the Commission directs NERC to submit an informational notice describing the basis for the changes at least 30 days in advance of the effective date of any such changes."	Performance Analysis	1/16/2014	Order No. 794	RM13-11-000	P 100	2017-01	Modifications to BAL-003-1.1	Ongoing. Table 1 in Attachment A has not been updated; however, Project 2017-01 will be proposing Table 1 changes.
S- Ref 10871 - "As discussed below, we also direct NERC to develop a means to assure that IROLs are communicated to transmission owners." P 41 - "NERC should establish a clearly defined communication structure to assure that IROLs and changes to IROL status are timely communicated to transmission owners." P 42 - "We encourage NERC to inform us when it has developed means for communication of IROLs to transmission owners to help ensure that they receive notice of each of their applicable lines before the [FAC-003-2] standard becomes effective as to those lines."	Standards	3/21/2013	Order No. 777	RM12-4-000	PP 6, 41, 42	2015-09	Establish and Communicate System Operating Limits	Ongoing; Communications are currently being addressed, but IROLS are also be addressed through Methods for Identifying IROLs Task Force
S- Ref 10820 : "[The Commission] believe[s] that NERC should register demand side aggregators if the loss of their load shedding capability, for reasons such as a cyber incident, would affect the reliability or operability of the Bulk-Power System."	Registration	1/18/2008	Order No. 706	RM06-22-000	P 51	N/A	N/A	Ongoing

Table 2: Status of Outstanding Directives								
Directive Summary	**Owner**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Project Number**	**Project Name**	**Status**
S-ref 10957- "[T]he Commission directs NERC, pursuant to Section 1600 of the NERC Rules of Procedure, to collect GIC monitoring and magnetometer data from registered entities for the period beginning May 2013, including both data existing as of the date of this order and new data going forward, and to make that information available."	Performance Analysis	9/22/2016	Order No. 830	RM15-11-000	P 89	N/A	N/A	NERC Board Approved Section 1600 Data Request in August 2018; NERC is developing detailed data reporting instructions and developing IT solutions to collect and store GMD data.
S-ref10954- P23 - "We also direct NERC to collect and report on data pertaining to the occurrence of Balancing Contingency Events that trigger resets of the 90-minute Contingency Reserve Restoration Period under Requirement R3." S-ref10954- P46 - "[T]he Commission directs NERC to collect and report data pertaining to: (1) additional megawatt losses following Reportable Balancing Contingency Events during the Contingency Reserve Restoration Period; and (2) the time periods for contingency reserve restoration under Requirement R3 and the number of resets of the 90-minute restoration period, and submit a report to the Commission two years following the first day of implementation of Requirement R3. After NERC reports on the data in a compliance filing, the Commission will consider what further action, if any, to take."	Performance Analysis	1/19/2017	Order No. 835	RM16-7-000	PP 23 and 46	N/A	N/A	Data is currently being collected. On track to be filed by the due date.

Table 2: Status of Outstanding Directives								
Directive Summary	**Owner**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Project Number**	**Project Name**	**Status**
S-ref 10955- "We further direct NERC to study and submit a report to the Commission with findings regarding reliability risks associated with most severe single contingency exceedances that do not result in energy emergencies."	Performance Analysis	1/19/2017	Order No. 835	RM16-7-000	P 23	N/A	N/A	Data is currently being collected.
"[W]e… direct NERC to conduct a study to assess the implementation of Reliability Standard CIP-003-7. The study should address what electronic access controls entities choose to implement and under what circumstances, and whether the electronic access controls adopted by responsible entities provide adequate security, as well as other relevant information found by NERC as a result of the study. NERC must file the study within eighteen months of the effective date of Reliability Standard CIP-003-7."	Standards	4/19/2018	Order No. 843	RM17-11-000	P 30	N/A	N/A	On track to be filed by due date.
"We adopt the NOPR proposal and, pursuant to section 215(d)(5) of the FPA, direct that NERC develop modifications to Reliability Standard CIP-003-7 to address our concern and ensure that responsible entities implement controls to mitigate the risk of malicious code that could result from third-party transient electronic devices. NERC could satisfactorily address the identified concern, for example, by modifying Section 5 of Attachment 1 to CIP-003-7 to clarify that responsible entities must implement controls to mitigate the risk of malicious code that could result from the use of third-party transient electronic devices."	Standards	4/19/2018	Order No. 843	RM17-11-000	P 37	2016-02	Modifications to CIP Standards	In development

Table 2: Status of Outstanding Directives								
Directive Summary	**Owner**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Project Number**	**Project Name**	**Status**
"We also find that it is reasonable for NERC to file annually an anonymized report providing an aggregated summary of the reported information, similar to the ICS-CERT annual report. The annual report will provide the Commission, NERC, and the public a better understanding of any Cyber Security Incidents that occurred during the prior year without releasing information on specific responsible entities or Cyber Security Events."	E-ISAC	7/19/2018	Order No. 848	RM18-2-000	P 90	N/A	Annual Report	Will submit annually after proposed CIP-008-6 becomes effective
"Thus, pursuant to section 215(d)(5) of the FPA, we direct NERC to develop modifications to the CIP Reliability Standards to include EACMS within the scope of the supply chain risk management Reliability Standards. We direct NERC to submit the directed modifications within 24 months of the effective date of this final rule."	Standards	10/18/2018	Order No. 850	RM17-13-000	P 30	N/A	N/A	Standards development project will begin after the final Supply Chain report is presented to the NERC Board at its May 2019 meeting.
"Accordingly, we accept NERC's commitment to evaluate the cybersecurity supply chain risks presented by PACS and PCAs in the cybersecurity supply chain risks study directed by the BOT. The Commission further directs NERC to file the BOT-directed final report with the Commission upon its completion."	Standards	10/18/2018	Order No. 850	RM17-13-000	P 31	N/A	N/A	The final Supply Chain report will be filed with FERC upon its completion and after the May 2019 NERC Board meeting.

Table 2: Status of Outstanding Directives								
Directive Summary	**Owner**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Project Number**	**Project Name**	**Status**
"As proposed in the NOPR, pursuant to section 215(d)(5) of the FPA, we also determine that it is appropriate to direct NERC to develop and submit modifications to Reliability Standard TPL-007-2 to require the development and completion of corrective action plans to mitigate assessed supplemental GMD event vulnerabilities . . . The Commission…directs NERC to submit the modified Reliability Standard for approval within 12 months from the effective date of Reliability Standard TPL-007-2."	Standards	11/15/ 2018	Order No. 851	RM10-8-000	P 29	2019-01	Modifications to TPL-007-3	In development – on track to be filed by due date.
"We also determine, pursuant to section 215(d)(5) of the FPA, that it is appropriate to direct that NERC develop further modifications to Reliability Standard TPL-007-2, Requirement R7.4 . . . [W]e direct NERC to develop a timely and efficient process, consistent with the Commission's guidance in Order No. 830, to consider time extension requests [for completion of Corrective Action Plan activities] on a case-by-case basis."	Standards	11/15/ 2018	Order No. 851	RM10-8-000	P 30	2019-01	Modifications to TPL-007-3	In development – on track to be filed by due date.
"Further, as proposed in the NOPR, we direct NERC to prepare and submit a report addressing how often and why applicable entities are exceeding corrective action plan deadlines as well as the disposition of time extension requests. The report is due within 12 months from the date on which applicable entities must comply with the last requirement of Reliability Standard TPL-007-2."	Standards	11/15/ 2018	Order No. 851	RM10-8-000	P 30	2019-01	Modifications to TPL-007-3	In development – on track to be filed by due date.

Chapter 3 – Conclusion

NERC is continuing to work closely with industry stakeholders and FERC to resolve all outstanding directives. Completing the majority of this work has provided the opportunity for industry to strategically review the standards and address as many directives as possible to date.

Appendix A – NERC Response to Directives on Vegetation Management on Federal Lands

NERC hereby provides the Commission information regarding analysis of access to federal lands and vegetation management as directed in Commission Order No. 693 and requested in Order No. 777.[14] In Order No. 693, the Commission issued directives focused on assessing any issues regarding minimum clearances on National Forest Service lands. In addition to the Commission's directives in Order No. 693, FERC reiterated in Order No. 777 that NERC should assess data to determine whether there were vegetation management issues on public lands.[15] Based on analysis of data regarding transmission outages, enforcement dispositions, and events, NERC concluded that the data reviewed did not indicate that limited access to federal lands for vegetation management poses a significant risk to the Bulk Electric System ("BES").

This response provides the analysis performed by NERC to determine whether there are vegetation management issues on public lands. Section I includes background on the Commission orders related to vegetation management on public lands. Section II provides information on the analysis of data collected performed by NERC.

Background on Commission Orders

In Order No. 693, FERC approved Reliability Standard FAC-003-1 and issued directives to NERC to further revise Reliability Standard FAC-003-1 and analyze vegetation management issues. Among others, the Commission directed NERC to "collect outage data for transmission outages of lines that cross both federal and non-federal lands, analyze it, and use the results of this analysis and information to develop a Reliability Standard that would apply to transmission lines crossing both federal and non-federal land."[16]

In Order No. 777, the Commission directed that "NERC should gather and analyze the necessary data regarding vegetation management issues on public lands. If NERC's analysis indicates that there are issues that should be addressed, NERC should propose a means to address the concern, for example by issuing an alert, or propose other appropriate action."[17] FERC noted in Order No. 777 that the directive to collect outage data for transmission outages of lines that cross both federal and non-federal lands was still outstanding in 2013.[18] In that order, FERC noted that it was "difficult for the Commission to gauge the nature or seriousness" of the issues raised by commenters without objective data.[19] Therefore, FERC reiterated that NERC should gather and analyze the necessary data regarding vegetation management issues on public lands.

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14 *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) ("Order No. 693"); *Revisions to Reliability Standard for Transmission Vegetation Management*, Order No. 777, 142 FERC ¶ 61,208, (2013) ("Order No. 777").

15 Order No. 777 at P 130.

16 Order No. 693 at P 732.

17 Order No. 777 at P 130.

18 *Id.* at P 129.

19 *Id.*

NERC Analysis

In response to the statement in Order No. 777 regarding "necessary data," NERC reviewed the following data: (A) NERC enforcement data; (B) information reported through NERC's Event Analysis process; and (C) information collected from entities owning or operating transmission assets. NERC concludes that, based on the available data, there are no major risks to BES reliability caused by issues with access to federal and public lands for vegetation management. While some entities report that permitting processes to access or perform vegetation management on federal or public lands add challenges to the vegetation management process, NERC concludes that, based on the data reviewed,[20] these processes have not contributed to transmission outages or violations.

Review of Enforcement Data

NERC reviewed its enforcement data to identify reported vegetation management issues by the responsible entities related to federal lands. First, NERC reviewed vegetation-related transmission outages reported pursuant to the Periodic Data Submittal of currently effective Reliability Standard FAC-003-4. Second, NERC reviewed data on noncompliance with Reliability Standards FAC-003-3 and FAC-003-4 for any issues related to access to federal or public lands. Each of these areas and NERC's resulting analysis is discussed in turn below.

Applicable Transmission Owners and Generator Owners submit quarterly reports on Sustained Outages[21] caused by vegetation to their Regional Entities as part of the Periodic Data Submittal in Reliability Standard FAC-003-4. The Regional Entities in turn submit the reports to NERC. NERC then posts quarterly and annual reports on this data.[22]

NERC reviewed this data for the past five years to determine whether any reported outages were related to vegetation management on federal land. The data did not indicate that any reported transmission outages or vegetation contacts within the last five years were due to issues between electric utilities and federal or public landowners.

NERC also reviewed its enforcement dispositions, including those filed and those in process, related to Reliability Standards FAC-003-3 and FAC-003-4 from 2008 until January 2019.[23] This data set included 9 Compliance Exceptions; 9 Find, Fix, Track, and Reports; 87 Notices of Penalty; 2 Administrative Citation Notices of Penalty; and 9 Spreadsheet Notices of Penalty. Within this data set, NERC did not find

[20] NERC did not include the Transmission Availability Data System ("TADS") in its review. In TADS, NERC compiles information on transmission outages collected from applicable entities through a mandatory data request. The TADS template includes fields to select cause codes for transmission outages, including vegetation as a cause of an outage. This information, when analyzed at the regional and continent-wide level, provides data that may help to improve reliability. TADS, however, does not collect information on whether outages are occurring on federal or public lands. In addition, the cause codes on the reporting template do not indicate whether any outages caused by vegetation were due to limited or delayed access to federal or public lands for vegetation management. Due to these two factors, NERC cannot conclude from TADS data whether any of the reported outages resulted from vegetation management issues on federal or public land.

[21] The Glossary of Terms Used in NERC Reliability Standards defines Sustained Outage as, "The deenergized condition of a transmission line resulting from a fault or disturbance following an unsuccessful automatic reclosing sequence and/or unsuccessful manual reclosing procedure." *Glossary of Terms Used in NERC Reliability Standards*, http://www.nerc.com/files/Glossary_of_Terms.pdf.

[22] Quarterly and annual reports from 2005 to the present are posted at: https://www.nerc.com/pa/comp/CE/Pages/vegetation-management-reports.aspx.

[23] Enforcement and mitigation information is available at: https://www.nerc.com/pa/comp/CE/Pages/Enforcement-and-Mitigation.aspx.

references to issues involving federal or public lands, such as access issues or implementation of vegetation management programs. NERC did note in some instances that mitigation plans included education on relationships between entities and federal or public entities for vegetation management purposes. Nonetheless, NERC concluded that this did not suggest that entities faced issues with federal or public entities leading up to the violation. These aforementioned dispositions seem to indicate that issues with access to federal or public lands to perform vegetation management did not cause or contribute to violations of Reliability Standards FAC-003-3 or FAC-003-4.

Events Analysis

The industry's voluntary Electric Reliability Organization ("ERO") events analysis ("EA") process provides information to the ERO and industry on the event categories and causes of qualifying events.[24] Review and analysis of this information can identify potential reliability risks or vulnerabilities to the Bulk Power System. During this process, participating entities identify the category of an event, choosing from Categories 1 through 5.[25] The level of analysis needed depends on this categorization as well as the facts and circumstances of the event. It is important to note that some incidents occur that do not meet threshold criteria for inclusion in the events analysis process. Since its initial implementation in October of 2010 until February 2019, the EA process has collected 1,274 qualifying events. Based on the analysis of these events, NERC did not find issues relating to access to federal or public lands for vegetation management as contributing to or causing qualifying events.

Information from Entities Owning or Operating Transmission Assets

NERC worked with the North American Transmission Forum ("NATF")[26] to gather information from entities owning or operating transmission assets crossing federal or public land. The NATF issued a voluntary survey to relevant entities and provided non-attributable, summary results of the survey to NERC. Responding entities mostly indicated they were able to access federal or public land to maintain vegetation appropriately. However, some responding entities did note that gaining access to federal or public land often involved permitting processes to perform necessary activities that lengthened the timeframe for completing such activities. In addition, responding entities stated that some herbicides typically used to treat vegetation either were not allowed or required a permit to use. Responding entities also noted some inconsistencies in how certain regulations were applied across agencies. While this information from responding entities indicates that vegetation management on federal or public lands may present additional challenges by taking longer to complete or requiring additional efforts and adjustments to work practices to gain access based on permitting or other factors, these entities did not indicate the issues led to transmission outages.

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[24] *Electric Reliability Organization Event Analysis Process Version 3.1*, (Jan. 1, 2017) https://www.nerc.com/pa/rrm/ea/ERO_EAP_Documents%20DL/ERO_EAP_v3.1.pdf ("EA Process Document").

[25] Qualifying events are assigned to one of five categories based on reliability impact to the BES, although the categories do not cover all possible events. The event categories are intended to allow the registered entity and RE to objectively identify event thresholds. Details on the categories are listed in the EA Process Document, available at: https://www.nerc.com/pa/rrm/ea/ERO_EAP_Documents%20DL/ERO_EAP_v3.1.pdf.

[26] The NATF is an organization consisting of members who "own[], operate[], or control[] at least 50 circuit miles of integrated (network) transmission facilities at 100 kV or above, operate[] a '24/7' transmission control center with NERC-certified transmission or reliability operators, or has an open access transmission tariff or equivalent on file with a regulatory authority." NATF, Forum Flyer (Feb. 2019), http://www.natf.net/docs/natf/documents/natf-flyer.pdf.

CONCLUSION

Following its review, NERC has concluded that the available data do not suggest the existence of issues relating to accessing federal or public land to perform vegetation management that led to transmission outages, violations, significant events, or other impacts to BES reliability. While the available data suggest that entities may face some timing challenges in accessing federal or public land to perform vegetation management relating to the regulatory process, the data also suggests that these issues are manageable and do not pose a significant risk to the reliability of the BES.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

March 6, 2019

VIA ELECTRONIC FILING

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

RE: Errata to Joint Petition for Approvals in Connection with the Dissolution of the Florida Reliability Coordinating Council, Inc.
Docket No. RR19-4-000

Dear Secretary Bose:

On February 27, 2019, the North American Electric Reliability Corporation ("NERC"), Florida Reliability Coordinating Council, Inc. ("FRCC"), and SERC Reliability Corporation ("SERC") submitted a joint petition for approvals in connection with dissolution of FRCC's Regional Entity function.

It has come to NERC's attention that Attachment 4 of the petition inadvertently included an out of date list of the Registered Entities that NERC proposes to transfer from FRCC RE's footprint to SERC's footprint. Please find attached updated clean and redline copies of this list. This errata does not materially modify the proposals in the joint petition and is filed out of an abundance of caution to ensure clarity.

For the reasons set forth above, NERC respectfully requests that the Commission accept this errata without change to the comment period and approve the proposals in the joint petition.

Respectfully submitted,

/s/ Candice Castaneda

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cc: Official service list in Docket No. RR19-4-000

Clean

Registered Entity List

NCR ID#	Entity Name	Proposed Regional Entity
NCR00003	Bartow, City of	SERC
NCR00004	Beaches Energy Services of Jacksonville Beach	SERC
NCR11010	City of Leesburg	SERC
NCR00054	City of Ocala Electric Utility	SERC
NCR10054	Covanta Palm Beach Resource Recovery, LLC.	SERC
NCR00063	Duke Energy Florida, LLC	SERC
NCR00021	Florida Keys Electric Cooperative Assn	SERC
NCR00022	Florida Municipal Power Agency	SERC
NCR00023	Florida Municipal Power Pool	SERC
NCR00024	Florida Power & Light Co.	SERC
NCR00025	Florida Public Utilities Company	SERC
NCR00464	Florida Reserve Sharing Group	SERC
NCR00027	Fort Pierce Utilities Authority	SERC
NCR00032	Gainesville Regional Utilities	SERC
NCR00069	General Electric International - Shady Hills	SERC
NCR11875	GenOn Florida	SERC
NCR00035	Hardee Power Partners Limited	SERC
NCR00037	Homestead, City of	SERC
NCR00039	Indiantown Cogeneration LP	SERC
NCR00040	JEA	SERC
NCR00041	Key West, City of (Keys Energy)	SERC
NCR00042	Kissimmee Utility Authority	SERC
NCR00043	Lake Worth, City of	SERC
NCR00044	Lakeland Electric	SERC
NCR00045	Lee County Electric Cooperative, Inc	SERC
NCR00052	New Smyrna Beach, Utilities Commission of	SERC
NCR11895	Oleander Holdings, LLC	SERC
NCR00057	Orlando Utilities Commission	SERC
NCR00065	Reedy Creek Improvement District	SERC
NCR00068	Seminole Electric Cooperative	SERC
NCR11896	Stanton Clean Energy, LLC	SERC
NCR00073	Tallahassee, City of	SERC
NCR00074	Tampa Electric Company	SERC

NCR00078	Vandolah Power Company, LLC	SERC
NCR00079	Vero Beach, City of	SERC
NCR00081	Winter Park, City of	SERC

Redline

Registered Entity List

NCR ID#	Entity Name	Proposed Regional Entity
NCR00003	Bartow, City of	SERC
NCR00004	Beaches Energy Services of Jacksonville Beach	SERC
NCR11010	City of Leesburg	SERC
NCR00054	City of Ocala Electric Utility	SERC
NCR10054	Covanta Palm Beach Resource Recovery, LLC.	SERC
NCR00063	Duke Energy Florida, LLC	SERC
NCR00021	Florida Keys Electric Cooperative Assn	SERC
NCR00022	Florida Municipal Power Agency	SERC
NCR00023	Florida Municipal Power Pool	SERC
NCR00024	Florida Power & Light Co.	SERC
NCR00025	Florida Public Utilities Company	SERC
~~NCR00026~~	~~Florida Reliability Coordinating Council, Inc.~~	~~SERC~~
NCR00464	Florida Reserve Sharing Group	SERC
NCR00027	Fort Pierce Utilities Authority	SERC
NCR00032	Gainesville Regional Utilities	SERC
NCR00069	General Electric International - Shady Hills	SERC
NCR11875	GenOn Florida	SERC
NCR00035	Hardee Power Partners Limited	SERC
NCR00037	Homestead, City of	SERC
NCR00039	Indiantown Cogeneration LP	SERC
NCR00040	JEA	SERC
NCR00041	Key West, City of (Keys Energy)	SERC
NCR00042	Kissimmee Utility Authority	SERC
NCR00043	Lake Worth, City of	SERC
NCR00044	Lakeland Electric	SERC
NCR00045	Lee County Electric Cooperative, Inc	SERC
NCR00052	New Smyrna Beach, Utilities Commission of	SERC
NCR11895	Oleander Holdings, LLC	SERC
NCR00057	Orlando Utilities Commission	SERC
NCR00065	Reedy Creek Improvement District	SERC
NCR00068	Seminole Electric Cooperative	SERC
~~NCR00071~~	~~Southern Power Company~~	~~SERC~~
NCR11896	Stanton Clean Energy, LLC	SERC

NCR00073	Tallahassee, City of	SERC
NCR00074	Tampa Electric Company	SERC
NCR00078	Vandolah Power Company, LLC	SERC
NCR00079	Vero Beach, City of	SERC
NCR00081	Winter Park, City of	SERC

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 6th day of March, 2019.

/s/ Marilani Alt

Marilani Alt
Senior Legal Assistant for the North American Electric Reliability Corporation

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

March 20, 2019

VIA ELECTRONIC FILING

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

Re: Joint Petition of the North American Electric Reliability Corporation and Texas Reliability Entity, Inc. for Approval of Amendments to the Texas Reliability Entity, Inc. Bylaws
Docket No. RR19-_-000

Dear Secretary Bose:

The North American Electric Reliability Corporation ("NERC") and Texas Reliability Entity, Inc. ("Texas RE") hereby submit for approval the "*Joint Petition of the North American Electric Reliability Corporation for Approval of Amendments to the Texas Reliability Entity, Inc. Bylaws*." Through the proposed amendments, Texas RE seeks to: (1) maintain consistency with the Texas Business Organizations Code ("BOC"); (2) clarify the qualifications for *ex officio* Directors on Texas RE's Board of Directors ("Board"); (3) clarify the term that Affiliated and *ex officio* Directors on Texas RE's Board can serve; (4) clarify the role of alternate representative for an *ex officio* Director; (5) allow the Chief Executive Officer ("CEO") of Texas RE to appoint an Independent Director to serve as his or her proxy; (6) clarify the process for filling vacant *ex officio* Director positions; (7) remove and/or revise obsolete, inconsistent, and outdated language; (8) align the Texas RE Bylaws with Texas RE's current business practices; (9) clarify the process for waiving notice of meetings; (10) clarify the process for establishing quorum for meetings; (11) clarify the process for waiving notice of Board meeting adjournment; (12) require the Board to approve proposed alternate procedures for nominating and electing representatives of Texas RE's

Member Representatives Committee; (13) clarify the Board's authority with respect to Texas RE's committees and subcommittees; (14) amend the procedure for temporarily filling a vacant Independent Director position on Texas RE's Director Compensation Committee; and (15) clarify and update the process for amending the Texas RE Bylaws.

This joint filing consists of: (1) this transmittal letter; (2) the narrative text of the Joint Petition that follows this transmittal letter; and (3) Attachments 1 and 2 to the Joint Petition that contain clean and redline versions of the proposed amendments to the Texas RE Bylaws, respectively. All documents are being transmitted in a single PDF file.

Please contact the undersigned if you have any questions concerning this joint filing.

Respectfully submitted,

/s/ Nina H. Jenkins-Johnston

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Counsel for the North American Electric Reliability Corporation

Dated: March 20, 2019

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation & Texas Reliability Entity, Inc.	**)**	**Docket No. RR19-_-000**

JOINT PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION AND THE TEXAS RELIABILITY ENTITY, INC. FOR APPROVAL OF AMENDMENTS TO THE TEXAS RELIABILITY ENTITY, INC. BYLAWS

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March 20, 2019

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ATTACHMENTS

ATTACHMENT 1: Amended and Restated Bylaws of Texas Reliability Entity, Inc.– Clean

ATTACHMENT 2: Amended and Restated Bylaws of Texas Reliability Entity, Inc.– Redline

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation & Texas Reliability Entity, Inc.	**)** **)**	**Docket No. RR19-_-000**

JOINT PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION AND THE TEXAS RELIABILITY ENTITY, INC. FOR APPROVAL OF AMENDMENTS TO THE TEXAS RELIABILITY ENTITY, INC. BYLAWS

Pursuant to Section 215(e)(4) of the Federal Power Act ("FPA")[1] and 18 C.F.R. §§ 39.1, 39.1 (2018), the North American Electric Reliability Corporation ("NERC") and Texas Reliability Entity, Inc. ("Texas RE") request the Federal Energy Regulatory Commission's ("Commission") approval of the proposed amendments to the Texas RE Bylaws.[2] These revisions resulted after Texas RE reviewed its Bylaws for consistency with the Texas Business Organizations Code ("BOC") and Texas RE's current business practices. The revisions were approved by Texas RE's Board of Directors ("Board") on December 5, 2018, and by the Texas RE membership on December 17, 2018. As described in greater detail in Section II of this Joint Petition, Texas RE proposes to amend the following sections of its Bylaws:

- revised Article IV, Section 1 ("Board of Directors: Board of Directors");
- revised Article IV, Section 2(b) ("Board of Directors: Independent Directors – Term");

[1] 16 U.S.C. § 824o (2018).

[2] Pursuant to the Commission's November 2, 2015 and March 23, 2016 orders in Docket Nos. RR15-12-000-001, Regional Entity bylaws and standard development procedures are no longer maintained as exhibits to the Regional Delegation Agreements. *N. Am. Elec. Reliability Corp.*, 153 FERC ¶ 61,135 (2015) and *N. Am. Elec. Reliability Corp.*, Docket No. RR15-12-001 (Mar. 23, 2016) (unpublished letter order). NERC maintains an up-to-date copy of each Regional Entity's bylaws and standard development procedure on its website at: http://www.nerc.com/AboutNERC/Pages/Regional-Entity-Delegation-Agreements.aspx.

- revised Article IV, Section 2(e) ("Board of Directors: Independent Directors – Alternates and Proxies");
- revised Article IV, Section 5(a)(3) and (b) ("Board of Directors: Vacancies and Removal");
- revised Article V, Section 1(a) – (b) ("Meetings of Members of the Corporation: Annual and Other Meetings of Members");
- revised Article V, Section 2(c) ("Meetings of Members of the Corporation: Quorum and Voting Requirements for Meetings of Members");
- revised Article V, Section 3 ("Meetings of Members of the Corporation: Waivers of Notice of Meetings of Members and Member Meeting Adjournments");
- revised Article VI, Section 3 ("Meetings of the Board of Directors: Quorum and Voting Requirements for Meetings of the Board");
- revised Article VI, Section 5 ("Meetings of the Board of Directors: Waivers of Notice of Board Meetings and Board Meeting Adjournments");
- revised Article VIII, Section 3(c) ("Member Representatives Committee: Election of Representatives of the Member Representatives Committee");
- revised Article IX ("Other Committees and Subcommittees");
- revised Article X, Section 1(a) ("Budgets and Funding: Compensation of the Board and Member Representatives Committee"); and
- revised Article XI, Section 1(a) – (b) ("Amendments to the Bylaws: Amendments to the Bylaws").

Texas RE also made several administrative/ministerial changes, which are reflected in the attached redline version while not addressed in detail herein.

NERC staff has determined that there are no reliability-related issues raised by the proposed amendments. As amended, the Texas RE Bylaws continue to satisfy the five governance criteria specified in Exhibit B to the Amended and Restated Delegation Agreement between Texas RE and NERC. Accordingly, the NERC Board of Trustees approved the proposed amendments to the Texas RE Bylaws at its February 7, 2019 meeting.

Attachments 1 and **2** to this joint petition are clean and redline versions, respectively, of the revised Texas RE Bylaws.

I. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this joint filing may be addressed to the following:[3]

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*Persons to be included on the Commission's official service list

[3] 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.

II. PROPOSED AMENDMENTS TO THE TEXAS RE BYLAWS

As detailed below, Texas RE proposes the following changes to its Bylaws to enhance consistency with the Texas BOC and Texas RE business practices.

A. Revised Article IV, Section 1 "Board of Directors: Board of Directors"

Texas RE proposes to clarify that one *ex officio* Directorship on its Board may only be held by the Office of Public Utility Counsel's ("OPUC") Texas Public Counsel. Under the current Bylaws, this seat can be held by either Texas Public Counsel or any other employee of the OPUC designated by the Texas Public Counsel.

B. Revised Article IV, Section 2(b) "Board of Directors: Independent Directors - Term"

Texas RE also proposes to revise its current Bylaws to clarify that an Affiliated Director term coincides with the terms of the Chair and Vice Chair of the Member Representatives Committee. Under the current Bylaws, Affiliated Directors, who are Chair and Vice Chair of the Member Representatives Committee, serve a two-year term. Due to the timing of elections, however, Chair and Vice Chair terms often span more than two years. The proposed amendment also explains that *ex officio* Directors, specifically the Public Utility Commission of Texas "PUCT" Chair (or designee) and the Texas Public Counsel, may only sit on the Board for the duration that they serve in their respective roles.

C. Revised Article IV, Section 2(e) "Board of Directors: Independent Directors - Alternates and Proxies"

Texas RE proposes to revise its current Bylaws to clarify that *ex officio* Directors may designate an alternate representative to attend public meetings only. The proposed revision also provides that Texas RE's Chief Executive Officer ("CEO") may designate an Independent Director as a proxy if unable to attend a Board meeting.

D. Revised Article IV, Section 5(a)(3) and (b) "Board of Directors: Vacancies and Removal"

Texas RE proposes to revise Article IV, Section 5(a)(3) to explain that a vacant *ex officio* Directorship should be filled by the appointment of a new PUCT Chair, the PUCT Chair's designee, or the appointment of a new Texas Public Counsel. The proposed revision also affects Section 5(b), removing redundant language regarding the removal of *ex officio* Directors, and clarifying that any Director facing removal cannot vote on his or her own removal. In the same section, Texas RE also proposes to remove language prohibiting the right to assign, sell, pledge, or transfer the right to elect Directors, as it is inconsistent the concept of proxies.

E. Revised Article V, Section 1(a) - (b) "Meetings of Members of the Corporation: Annual and Other Meetings of Members"

Texas RE proposes to remove language in Article V, Section 1(a) to: (1) clarify that if a meeting to elect Directors cannot be held in December, it will be held as soon as practicable thereafter; and (2) eliminate language providing that the failure to hold an annual meeting shall not affect the validity of a corporate action. The proposed revisions also affect Section 1(b) to: (1) clarify that a meeting may be called for any purpose(s) by a group constituting at least 10% of all members of Texas RE; and (2) eliminate a member's ability to "immediately elect" to become a member in a Sector for which it qualifies if it stops qualifying for another Sector, as that language conflicts with Article III, Section 5 of the Bylaws.

F. Revised Article V, Section 2(c) "Meetings of Members of the Corporation: Quorum and Voting Requirements of Meetings of Members"

Texas RE proposes to revise its current Bylaws to align the language in the Bylaws with its current business practice to keep membership votes open for at least ten days, unless good cause exists to hold a shorter election period.

G. Revised Article V, Section 3 "Meetings of Members of the Corporation: Waivers of Notice of Meetings of Members and Member Meeting Adjournments"

Texas RE proposes to revise Article V, Section 3 to clarify that members may only waive notice of a members' meeting in writing. This change is consistent with written waiver requirements under the BOC. Texas RE proposes similar amendments for meetings of the Board of Directors as well as the Member Representatives Committee.[4]

H. Revised Article VI, Section 3 "Meetings of the Board of Directors: Quorum and Voting Requirements for Meetings of the Board"

Texas RE proposes to eliminate the Board's ability to establish a quorum for Board meetings by proxy. This maintains consistency with the BOC and clarifies that the "in-person" requirement for quorum includes "by means of any communications system by which all persons participating in the meeting are able to hear each other."[5]

I. Revised Article VI, Section 5 "Meetings of the Board of Directors: Waivers of Notice of Board Meetings and Board Meeting Adjournments"

Texas RE proposes to clarify that when a Board meeting is adjourned to another time or place, it is not necessary to give notice of the adjourned meeting so long as: (1) the time and place of the adjourned meeting is announced at the original meeting; and (2) if at the adjourned meeting, only the business scheduled for the original meeting is transacted. Texas RE proposes similar changes for adjournment of meetings of the Member Representatives Committee.[6]

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[4] Attachment A, Amended and Restated Bylaws of Texas Reliability Entity, Inc., Article VI, Section 3 and Article VIII, Section 8 (approved Dec. 17, 2018).

[5] *Id*., Article VI, Section 3.

[6] *Id*., Article VIII, Section 8.

J. Revised Article VIII, Section 3(c) "Member Representatives Committee: Election of Representatives of the Member Representatives Committee"

Texas RE proposes to require the Board to approve any alternative procedures that a membership sector adopts for nominating and electing its representatives to Member Representatives Committee.

K. Revised Article IX "Other Committees and Subcommittees"

Texas RE proposes to clarify that the Board has the authority to create and determine the scope of all Texas RE committees and subcommittees. The revisions also explain that the Board may appoint the members of such committees, subcommittees, and task forces that are representative of Members and other interested parties.

L. Revised Article X, Section 1(a) "Budgets and Funding: Compensation of the Board and Member Representatives Committee"

Texas RE proposes to allow the Board Vice Chair to serve on the Director Compensation Committee if there is an Independent Director vacancy, until the vacancy is filled.

M. Revised Article XI, Section 1(a)-(b) "Amendments to the Bylaws"

Texas RE proposes to clarify that any proposed revision to the Bylaws should be sent to the Corporate Secretary, rather than the CEO, of Texas RE. Texas RE also proposes to update the process for amending the Bylaws to reflect the current practice at Texas RE. After the Corporate Secretary receives proposed amendments, proposed Bylaws revisions may either go directly to the Board or to a Board-designated standing committee that is authorized to review proposed amendments for recommendation to the Board.

III. TEXAS RE AND NERC APPROVALS OF THE PROPOSED AMENDMENTS

The proposed amendments can be separated into two sets of approvals for: (1) approval by the Texas RE Board on December 5, 2018; and (2) approval by the Corporate Members on

December 17, 2018. The NERC Board of Trustees approved the proposed amendments at its February 7, 2019 meeting.

IV. CONCLUSION

NERC and Texas RE respectfully request that the Commission approve the proposed amendments to the Texas RE Bylaws, as shown in **Attachment 1** and **Attachment 2** to this Joint Petition.

Respectfully submitted,

/s/ Nina H. Jenkins-Johnston

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Dated: March 20, 2019

ATTACHMENT 1

Amended Bylaws

Texas Reliability Entity, Inc. – Clean

AMENDED AND RESTATED BYLAWS

OF

TEXAS RELIABILITY ENTITY, INC.

(A Texas Non-Profit Corporation)

Approved by Membership – December 17, 2018

Approved by Federal Energy Regulatory Commission – _____

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ARTICLE I.
DEFINITIONS

Section 1. Definitions. The capitalized terms used in these Bylaws of Texas Reliability Entity, Inc. (the "Corporation" or "Texas RE"), shall have the meanings set forth below, or if not set forth below, shall have the meanings given them in the NERC Rules of Procedure.

(a) "Affiliate" means any entity controlling, controlled by or under common control with the entity under consideration, and includes any entity (i.e., any commercial enterprise) in any of the following relationships: (i) an entity that directly or indirectly owns or holds at least five percent of the voting securities of another entity, (ii) an entity in a chain of successive ownership of at least five percent of the voting securities of another entity, (iii) an entity which shares a common parent with or is under common influence or control with another entity or (iv) an entity that actually exercises substantial influence or control over the policies and actions of another entity. Evidence of influence or control shall include the possession, directly or indirectly, of the power to direct or cause the direction of the management and/or policies and procedures of another, whether that power is established through ownership or voting of at least five percent of the voting securities or by any other direct or indirect means. In cases where the level of control or influence is disputed, the Board shall have discretion to determine whether or not the entities are Affiliates of one another. Membership in Texas RE shall not create an affiliation with Texas RE.

(b) "Board" means the Board of Directors of the Corporation.

(c) "Bulk Power System" or "BPS" means facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof) and facilities generating electric energy as needed to maintain transmission system reliability, but does not include facilities used in the local distribution of electricity.

(d) "Delegated Authority" means the authority delegated by NERC to the Corporation to propose and enforce NERC Reliability Standards and perform other reliability-related activities in the ERCOT region under the Delegation Agreement executed by NERC and the Corporation and approved by the Federal Energy Regulatory Commission, pursuant to Section 215 of the Federal Power Act (16 U.S.C. §824o).

(e) "Delegation Agreement" means the agreement between the Corporation and NERC and approved by FERC, which describes the Delegated Authority and may be amended from time to time.

(f) "Electric Reliability Organization" or "ERO" means the organization that is certified by FERC pursuant to Section 39.3 of its regulations, and has received recognition by appropriate regulatory authorities in Canada and Mexico, as applicable, to establish and enforce Reliability Standards for the Bulk Power Systems of the respective countries and that has entered into a delegation agreement with the Corporation pursuant to which the Electric Reliability Organization delegates enforcement authority for Reliability Standards for the Bulk Power System in the ERCOT region. NERC was certified as the ERO on July 20, 2006.

(g) "ERCOT region" means the geographic area and associated transmission and distribution facilities that are not synchronously interconnected with electric utilities operating outside the jurisdiction of the Public Utility Commission of Texas.

(h) "FERC" means the Federal Energy Regulatory Commission.

(i) "Independent Director" means a person who is not (a) an officer or employee of the Corporation; (b) a NERC Registered Entity or Member or an officer, director, or employee of a Member of the Corporation; or (c) an officer, director, or employee of any company or entity that would reasonably be perceived as having a direct financial interest in the outcome of Board decisions or having a relationship that would interfere with the exercise of independent judgment in carrying out the responsibilities of a Director, as more specifically described in Article IV of these Bylaws.

(j) "Member" means a member of the Corporation pursuant to Article III of these Bylaws.

(k) "NERC" means North American Electric Reliability Corporation, the entity certified by FERC as the ERO on July 20, 2006.

(l) "NERC Rules of Procedure" means the Rules of Procedure that are adopted by NERC and approved by FERC.

(m) "PUCT" means the Public Utility Commission of Texas.

(n) "OPUC" means the Texas Office of Public Utility Counsel.

(o) "Originally Elected Independent Director" means a Director approved by the membership on June 2, 2010, in the first election of Texas Reliability Entity, Inc. Independent Directors.

(p) "Regional Entity" means an entity with a Delegation Agreement with NERC, as ERO.

(q) "Regional Reliability Standard" means a standard or variance for the ERCOT region that is proposed and approved in accordance with the Texas RE Standards Development Process and either, (i) sets more stringent reliability requirements than a national Reliability Standard, or (ii) covers matters not covered by a national Reliability Standard.

(r) "Registered Entity" means an entity that is registered with NERC and listed on the NERC Compliance Registry (available at www.nerc.com).

(s) "Reliability Standard" means a requirement to provide for Reliable Operation of the Bulk Power System, which is approved by NERC and FERC, pursuant to Section 215 of the Federal Power Act and all amendments thereto. This term includes requirements for the operation of existing Bulk Power System facilities, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary to provide for Reliable Operation of the Bulk Power System.

(t) "Reliable Operation" means operating the elements of the Bulk Power System within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of the Bulk Power System will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.

(u) "Sector" means a group of Members of the Corporation that are Bulk Power System owners, operators, or users, as defined in Article III, Section 4 of these Bylaws. Each

Sector shall constitute a class of Members for purposes of Chapter 22 (Nonprofit Corporations) of the Texas Business Organizations Code.

ARTICLE II.
PURPOSE

Section 1. General Purpose. The purpose of the Corporation is to preserve and enhance electric reliability in the ERCOT region. In furtherance of this goal, the Corporation will:

(a) Perform Reliability Standards development, compliance monitoring, compliance enforcement, and other related activities as a Regional Entity, pursuant to 16 U.S.C. §824o, in accordance with the Corporation's Delegation Agreement with NERC;

(b) Carry out other activities as set forth in the Delegation Agreement, the NERC Rules of Procedure, or as otherwise required or requested by NERC, in support of the Delegated Authority, including but not limited to organization registration and certification, reliability assessment and performance analysis, training and education, and situational awareness and infrastructure security; and

(c) Engage in any other lawful act or activity that is not in conflict with the Corporation's duties as a Regional Entity and for which non-profit corporations may be organized under the Texas Business Organizations Code.

Section 2. Non-Profit Corporation. The Corporation is a Texas non-profit corporation.

Section 3. Geographic Area. The Corporation will perform its operations primarily within the ERCOT region.

ARTICLE III.
MEMBERSHIP

Section 1. Members. The Corporation is a membership corporation. Membership in the Corporation is voluntary and is open only to any entity that is a user, owner or operator of the ERCOT region Bulk Power System, registers with the Corporation as a Member, maintains its registration in accordance with this Article III, and complies with the other conditions and obligations of membership specified in these Bylaws. All Members must qualify and be registered in one of the Sectors defined in Article III, Section 4. Membership in the Corporation is not a condition to participating in the development or consideration of proposed Regional Standards.

Section 2. Registration as a Member. Any entity that is eligible to be a Member of the Corporation in accordance with Article III, Section 1 may become a Member by completing and submitting to the Corporation a membership registration on a form prescribed by the Corporation. The Member shall designate one representative and an alternative representative with authority to receive notices, cast votes, and execute waivers and consents on behalf of the Member. The Corporate Secretary shall maintain a current roster of the Members of the Corporation including each Member's designated representative and alternative representative. All Members shall be required to renew or reaffirm their registrations annually. The Corporate Secretary may remove any Member from the roster that has not submitted a registration renewal or reaffirmation by a date established by the Corporation.

Section 3. Obligations and Conditions of Membership.

(a) Members must agree to promote, support, and comply with Reliability Standards, and assist the Corporation in its compliance with the terms and provisions of the Corporation's Delegation Agreement with NERC. Each Member shall agree, in writing, to accept the responsibility to comply with policies of NERC and the Corporation as set forth in their respective certificates of formation, bylaws, rules of procedure, and Reliability Standards, as applicable, as from time to time adopted, approved, or amended.

(b) As an additional condition of membership in the Corporation, each Member shall be required to execute an agreement with the Corporation, in a form to be specified by the Corporation, that such entity will hold all Directors, officers, employees, and agents of the Corporation, as well as volunteers participating in good faith in the activities of the Corporation, harmless for any injury or damage caused by any act or omission of any director, officer, employee, agent, or volunteer in the course of performance of his or her duties on behalf of the Corporation, other than for willful acts of misconduct.

(c) Consistent with applicable laws and regulations, Members must share nonproprietary information at the Corporation's request as necessary for the furtherance of the Corporation's activities and consistent with NERC, PUCT, or any other applicable rules relating to confidentiality.

Section 4. Membership Sectors. Each Member shall elect to be assigned to one of the following membership Sectors:

(a) **System Coordination and Planning**: An entity that is registered with NERC as a Reliability Coordinator (RC), Balancing Authority (BA), Planning Authority (PA), or Resource Planner (RP).

(b) **Transmission and Distribution**: An entity that is registered with NERC as a Transmission Owner (TO), Transmission Planner (TP), Transmission Service Provider (TSP), Distribution Provider (DP), and/or Transmission Operator (TOP) and is not a Cooperative or Municipal Utility.

(c) **Cooperative Utility**: An entity that is (a) a corporation organized under Chapter 161 of the Texas Utilities Code or a predecessor statute to Chapter 161 and operating under that chapter; or (b) a corporation organized as an electric cooperative in a state other than Texas that has obtained a certificate of authority to conduct affairs in the State of Texas or (c) a cooperative association organized under Chapter 251 of the Texas Business Organizations Code and is registered with NERC for at least one reliability function.

(d) **Municipal Utility**: A municipally owned utility as defined in Public Utility Regulatory Act, Tex. Util. Code §11.003 and is registered with NERC for at least one reliability function.

(e) **Generation**: An entity that is registered with NERC as a Generator Owner (GO) or Generator Operator (GOP).

(f) **Load-Serving and Marketing**: An entity that secures wholesale transmission service or is engaged in the activity of buying and selling of wholesale electric power in the ERCOT region on a physical or financial basis, or qualifies under any newly defined NERC reliability function for demand response.

Section 5. Participation.

(a) There is only one level of Membership, and no company or entity may simultaneously hold more than one Membership.

(b) Members must qualify in and join a Sector.

(c) A Member that is eligible for more than one Sector may join only one Sector and it must be the most appropriate Sector for its business. Any disputes regarding appropriateness of a Member's Sector will be decided by a majority vote of the Board.

(d) A company or entity that is an Affiliate of a Member may hold a separate membership in a different Sector if the companies are separate legal entities.

(e) A Member must continue to vote in the same Sector for a minimum of the remainder of the membership year in which it becomes a Member or until it is no longer eligible to remain in such Sector, and it must give notice to the Corporate Secretary when it elects or is required to change Sectors.

(f) The Corporate Secretary may review the Sector qualification of any Member and upon a determination that a Member does not qualify for membership in a particular Sector, may require the Member to change Sectors or may terminate their membership.

(g) A Member that is no longer eligible or that is not in good standing may not vote on any matters that require membership.

Section 6. Membership Fees. There is no Membership Fee to join the Corporation.

Section 7. Term of Membership. Membership in the Corporation must be renewed or reaffirmed on an annual basis and will only be retained as long as a Member meets its respective qualifications, obligations, and conditions of membership as set forth in these Bylaws.

Section 8. Disciplinary Action. A Member or Member representative may be sanctioned, suspended, or expelled pursuant to a procedure that is fair and reasonable and is carried out in good faith. The Board will establish a procedure to sanction, suspend, or expel a Member that includes notice to the Member and exercise of appropriate due process procedures, and allows for a determination by the Board in its sole discretion that in its judgment the Member has violated its obligations and responsibilities to the Corporation.

Section 9. Resignation. Any other provision of these Bylaws notwithstanding, any Member may withdraw from participation in the activities of the Corporation at any time upon written notice to the Secretary of the Corporation, whereupon it shall cease to be a Member, and its representatives shall cease to be entitled or obligated to participate in the activities of the Board or any activities requiring membership.

Section 10. Reinstatement. A former Member, except a Member subject to Disciplinary Action under Section 8, may submit a membership application form to rejoin the Corporation as a Member. A Member disciplined under Section 8 may submit a written request for reinstatement of Membership. The request for reinstatement will be considered by the Board, and will be granted or denied within the sole discretion of the Board.

ARTICLE IV.
BOARD OF DIRECTORS

Section 1. Board of Directors. The business and affairs of the Corporation shall be managed by the Board. The Board shall consist of (i) four (4) Independent Directors who are nominated and elected in accordance with the requirements and procedures specified in this Article IV (the "Independent Directors"); (ii) the Chairman of the PUCT or another PUCT Commissioner designated by the Chairman, as an *ex officio* non-voting member; (iii) Texas Public Counsel, from OPUC as an *ex officio* non-voting member, representing the interests of residential and small commercial electricity consumers; (iv) the CEO of the Corporation as a voting member (the "Management Director"); (v) the chair of the Member Representatives Committee as a voting member; and (vi) the vice chair of the Member Representatives Committee as a voting member. The Directors who are the chair and vice chair of the Member Representatives Committee will be collectively referred to herein as "Affiliated Directors." All Directors are expected to serve the public interest and to represent the reliability concerns of the entire ERCOT region Bulk Power System.

Section 2. Independent Directors. The Independent Directors shall be elected, shall have the qualifications specified, and shall serve in the manner provided in this Section.

(a) Qualifications:

(1) Experience in one or more of these fields: senior corporate leadership; professional disciplines of finance, accounting, engineering, bulk power systems, or law; regulation of utilities; and/or risk management.

(2) Independence of any NERC Registered Entity. Requirements of independence include but are not limited to the following:

(i) Independent Directors and the spouse, mother, father, sibling, or dependent, and any spouse of mother, father, or sibling and including any step and adoptive parents, siblings or children, and household members of Independent Directors and their spouses shall not have current or recent status (within the last two years) as a director, officer, or employee of an ERCOT region NERC Registered Entity.

(ii) Independent Directors and immediate family (any spouse or dependent) and household members of Independent Directors shall not have current status as a director, officer, or employee of a non-ERCOT region NERC Registered Entity.

(iii) Independent Directors and immediate family and household members of Independent Directors shall not have direct business relationships, other than retail customer relationships, with any NERC Registered Entity.

(iv) Independent Directors and immediate family and household members of Independent Directors shall not own stocks or bonds of NERC Registered Entities or their affiliates. To the extent that an Independent Director or his or her spouse, dependent child, or any other household member owns stocks or bonds of NERC Registered Entities, these must be divested or placed in a blind trust prior to being seated on the Board. Ownership in broadly diversified

mutual funds or similar funds, which may include stocks or bonds of NERC Registered Entities or their affiliates, is not prohibited.

(v) Independent Directors shall not have any relationship that would interfere with the exercise of independent judgment in carrying out the responsibilities of a Board member, including the Delegated Authority.

(vi) Other criteria as approved by the Board.

(b) Term. The term for Independent Directors shall be staggered three year terms. An Independent Director may be elected for up to three consecutive terms. For the Originally Elected Independent Directors, two positions will have three-year terms, one position will have a two-year term, and one position will have a one-year term, and these terms shall not be counted for purposes of term limits. The term for the Affiliated Directors shall coincide with their terms as chair and vice chair of the Member Representatives Committee. The terms of the *ex officio* Directors terminate when the individual ceases to be Chairman of the PUCT (or the PUCT Chairman designates another Commissioner) or ceases to be Texas Public Counsel. If an Independent Director is elected to fill an unexpired term in the event of a vacancy, that term shall not be counted for purposes of term limits.

(c) Selection.

(1) The Board shall appoint, on an annual basis, or more frequently if needed in the event of a special election pursuant to this subsection, a nominating committee (the "Nominating Committee") to recommend candidates (i) to succeed the Independent Directors whose terms expire during the current year; (ii) to serve the remainder of the term of any Independent Director who ceased to serve as a Director subsequent to the last annual election of Directors; (iii) to serve as the Chair and Vice Chair on an annual basis; and (iv) to serve as CEO in the event of a vacancy. The Nominating Committee shall consist of two (2) Independent Directors whose terms do not expire during the current year and are not seeking re-election and one (1) Affiliated Director. The PUCT Chairman (or the PUCT Commissioner designated by the Chairman) may choose to participate on the Nominating Committee. The Board Chair shall appoint the Chair of the Nominating Committee. The Nominating Committee may retain an executive search firm to locate and present candidates to serve as Independent Directors with the required qualifications, as set forth in Article IV, Section 2(a) or to locate and present candidates to serve as CEO. Meetings of the Nominating Committee are not required to be publicly posted.

(2) The Nominating Committee shall select and nominate, by at least a two-thirds majority, qualified candidate(s) to serve as Independent Directors to present to the Membership for its approval. The Nominating Committee shall strive to ensure that the Board as a whole reflects expertise in the areas of technical electric operations and reliability, legal, senior corporate leadership, financial, risk management, and regulatory matters, and familiarity with regional system operation issues in the ERCOT region.

(3) The Membership shall vote by Sector as described in Article V in favor or against the proposed Independent Director(s). A proposed Independent Director who is approved by a majority of the Sectors shall become an Independent Director.

(4) The Nominating Committee shall select and recommend to the Board, by at least a two-thirds majority, a qualified candidate to serve as CEO. The Directors may choose to participate in interviewing CEO candidates.

(d) Director Voting Weights. All voting Directors shall have a single vote each.

(e) Alternates and Proxies. Independent Directors may designate another Independent Director as a proxy if unable to attend a Board meeting. *Ex officio* Directors may designate an alternate representative who may attend public meetings in the absence of such Director. The chair and vice chair of the Member Representatives Committee may designate each other or may designate an Independent Director as their proxy if unable to attend a Board meeting. The CEO may designate an Independent Director as a proxy if unable to attend a Board meeting.

Section 3. Appointment of Management Director. The president and chief executive officer (CEO) of the Corporation shall serve as the Management Director of the Corporation, effective as of the date of his or her appointment by the Board as CEO of the Corporation in accordance with these Bylaws, to serve until such time that he or she ceases to hold the position of CEO. No action of the Members of the Corporation shall be required in connection with the appointment of the CEO as the Management Director of the Corporation.

Section 4. Chair and Vice Chair. Annually, the Board shall elect from the Board's membership, by resolution of the Board, a Chair and a Vice Chair. The Chair and Vice Chair shall each be one of the Independent Directors.

Section 5. Vacancies and Removal.

(a) Should any vacancy on the Board arise from the death, resignation, retirement, disqualification, or removal from office of any Director, or from any other cause, such vacancy shall be filled as follows:

(1) For an Independent Director, by the election of a new Independent Director at the next annual election of Directors to fill the remainder, if any, of the term of the departed Independent Director; provided, that the Board by resolution may in its discretion call a special election to fill any such vacancy for the remainder, if any, of the term of the departed Independent Director.

(2) For the Management Director, by the appointment of a new CEO or interim CEO to fill the vacancy.

(3) For an *ex officio* Director, by the appointment of a new PUCT Chair (or the Chair's designee) or the appointment of a new Texas Public Counsel.

(4) For an Affiliated Director, by the election of a new chair or vice chair, as applicable, by the Member Representatives Committee.

(b) An Independent Director may be removed by an affirmative vote of sixty percent (60%) of the Members. In addition, the Board may remove any voting Director for cause, upon at least seventy-five percent (75%) affirmative votes of the eligible, remaining voting Directors, not counting any Director whose removal is under consideration.

Section 6. Committees of the Board. The Board shall by resolution create and appoint all committees of the Board as the Board deems necessary to perform its responsibilities. All committees of the Board shall have such duties as are prescribed and delegated by the Board. Committees to which any of the authority of the Board to manage the Corporation is delegated must have at least two Directors, and a majority of the members of the committee must be Directors.

ARTICLE V.
MEETINGS OF MEMBERS OF THE CORPORATION

Section 1. Annual and Other Meetings of Members.

(a) An annual meeting of the Members to elect Directors, announce election results from electronic elections, and conduct such other business as may come before the meeting, shall be held in December each year, or as soon as practicable thereafter.

(b) Meetings of Members of the Corporation may be called for any purpose or purposes by resolution of the Board, by the chair of the Board, the CEO or the Corporate Secretary, or by a number of Members constituting at least ten percent (10%) of all Members on the roster of Members maintained by the Corporate Secretary. Meetings of Members shall be held at the principal office of the Corporation or at such other place fixed by the Board as shall be specified in the notice of meeting. Meetings shall be called upon written notice of the time, date, place, and purposes of the meeting given to all Members on the roster of Members maintained by the Corporate Secretary not less than ten (10) nor more than sixty (60) days prior to the date of the meeting. Only Members in good standing with the Corporation, as determined by the Board, have the right to vote at any meeting of the Members.

Section 2. Quorum and Voting Requirements for Meetings of Members.

(a) At any meeting of the Members of the Corporation, attendance in person or by proxy by a majority of the Members in each of at least two-thirds of the Sectors on the roster of Members maintained by the Corporate Secretary shall constitute a quorum.

(b) Except as otherwise expressly provided in the Corporation's Certificate of Formation, these Bylaws, or applicable law, Members shall vote by Sector and each Sector shall have one vote.

(c) To the extent practicable, membership votes will be conducted electronically and prior to annual membership meetings, and will generally be open for a ten (10) day period unless good cause exists to shorten the period.

(d) Except as otherwise expressly provided in the Corporation's Certificate of Formation, these Bylaws or applicable law, actions by the Members of the Corporation shall be approved upon receipt of the affirmative vote of a majority of the Sectors of the Corporation at (1) a meeting at which a quorum is present, in person or by proxy, or (2) an electronic vote which has participation by a quorum. Each Sector's vote shall be determined by the affirmative vote of a majority of the members of the Sector voting at the meeting or in the electronic election.

Section 3. Waivers of Notice of Meetings of Members and Member Meeting Adjournments. Notice of a meeting of Members need not be given to any Member who waives noticein writing, whether before, during, or after the meeting. The attendance of any Member at a meeting, in person or by proxy, without protesting prior to the conclusion of the meeting the lack

of proper notice of such meeting, shall constitute a waiver of notice of the meeting by such Member. When any meeting of Members is adjourned to another time or place, it shall not be necessary to give notice of the adjourned meeting if the time and place to which the meeting is adjourned are announced at the meeting at which the adjournment is taken, and if at the adjourned meeting only such business is transacted as might have been transacted at the original meeting.

Section 4. Action Without a Meeting of Members. Any action, required or permitted to be taken at a meeting of Members, may be taken without a meeting if the proposed action is posted to all Members (via direct email or email to an email distribution list to which Members may subscribe and by posting on the Corporation website) and consented to in writing by the minimum number of Members that would be required to approve the action at a meeting of the Members at which all Members were present. The voting in such a circumstance shall be performed in writing, including via email or other electronic means. The Members shall receive written notice of the results within ten (10) days of the action vote, and all written responses of the Members shall be filed with the Corporate records. The results of such voting will be posted on the Corporation's website.

Section 5. Meetings of the Members to be Open. Notice to the public of the dates, places, and times of meetings of the Members, and all non-confidential material provided to the Members, shall be posted on the Corporation's website at approximately the same time that notice is given to the Members. Meetings of the Members shall be open to the public, subject to reasonable limitations due to the availability and size of meeting facilities; provided, that the meeting may be held in or adjourned to closed session to discuss matters of a confidential nature, including but not limited to compliance and enforcement matters, personnel matters, litigation, or commercially sensitive or critical infrastructure information of the Corporation or any other entity.

ARTICLE VI.
MEETINGS OF THE BOARD OF DIRECTORS

Section 1. Regular Meetings of the Board. Regular meetings of the Board shall be held at least quarterly. By resolution adopted at any meeting of the Board, the Board may provide for additional regular meetings that may be held as needed.

Section 2. Special Meetings of the Board. Special meetings of the Board for any purpose or purposes may be called at any time by the chair or by any two Directors. Such meetings may be held upon notice given to all Directors not less than three (3) days prior to the date of the meeting. Such notice shall specify the time, date, place, and purpose or purposes of the meeting and may be given by telephone, email, or other electronic media, or by express delivery.

Section 3. Quorum and Voting Requirements for Meetings of the Board. Unless otherwise expressly provided in the Corporation's Certificate of Formation, these Bylaws or applicable law, (i) the quorum necessary for the transaction of business at meetings of the Board shall be a majority of the voting Directors in person (including by means of any communications system by which all persons participating in the meeting are able to hear each other), of which at least three must be Independent Directors, and (ii) actions by the Board shall be deemed approved upon receipt of the affirmative vote of a majority of the Directors present and voting in person (including by means of any communications system by which all persons participating in the meeting are able to hear each other) or by proxy at a meeting at which a quorum is present but in no case less than four votes.

Section 4. Meetings of the Board to be Open. Notice to the public of the dates, places, and times of meetings of the Board, and all non-confidential material provided to the Board, shall be posted on the Corporation's website at approximately the same time that notice or such material is given to the Directors and at least five (5) business days prior to the scheduled meeting. Meetings of the Board shall be open to the public, subject to reasonable limitations due to the availability and size of meeting facilities; provided, that the Board may meet in or adjourn to closed session to discuss matters of a confidential nature, including but not limited to compliance and enforcement matters, personnel matters, litigation, or commercially sensitive or critical infrastructure information of the Corporation or any other entity. Any or all of the Directors or members of a Board committee, may participate in a meeting of the Board, or a meeting of a committee, in person or by proxy, by means of any communications system by which all persons participating in the meeting are able to hear each other.

Section 5. Waivers of Notice of Board Meetings and Board Meeting Adjournments. Notice of a meeting of the Board need not be given to any Director who waives notice in writing, whether before, during, or after the meeting. The attendance of any Director at a meeting, in person or by proxy, without protesting prior to the conclusion of the meeting the lack of proper notice of such meeting, shall constitute a waiver of notice of the meeting by such Director. When a meeting of the Board is adjourned to another time or place, it shall not be necessary to give notice of the adjourned meeting if the time and place to which the meeting is adjourned are announced at the meeting at which the adjournment is taken and if at the adjourned meeting, only such business is transacted as might have been transacted at the original meeting.

Section 6. Action Without a Meeting. Any action required or permitted to be taken at a meeting of the Board, or of any committee thereof, may be taken by the Board or by the committee without a meeting if the action is consented to in writing by the number of Directors or members of the committee, as the case may be, entitled to vote on the action that would be required to approve the action at a meeting of the Board or committee with all members of the Board or committee present. The call for action without a meeting of the Board may be initiated by the chair or by any two voting Directors. Notice of the proposed call for action without a meeting, and all non-confidential material provided to the Board in connection with the call for action without a meeting, shall be posted on the Corporation's website and shall be sent via email to an email distribution list to which Members and the public may subscribe at approximately the same time notice of the call for action without a meeting or such material is provided to the Board. The call for action without a meeting of a committee of the Board may be initiated by the chair of the committee or by any two members of the committee. The Directors or members of the committee shall receive written notice of the results of such action within seven (7) days of the action vote. All written responses of the Directors shall be filed with the minutes of the Corporation, and all written responses of members of a committee shall be filed with the minutes of such committee.

Section 7. Emergency Meetings. The Board may meet on urgent matters with not less than two (2) hours' public notice, as necessary or appropriate for emergency conditions threatening health or safety or a reasonably unforeseen situation.

ARTICLE VII.
OFFICERS

Section 1. Selection of Officers. The Board shall elect a CEO and shall ratify the selection of the officers of the Corporation (collectively, the "Officers"). The Management Director shall not participate in votes electing or ratifying Officers. The Corporation shall maintain

a list of current Officers ratified by the Board. The duties and authority of the Officers shall be determined from time to time by the Board. Subject to any such determination, the Officers shall have the following duties and authority:

Section 2. Chief Executive Officer ("CEO"). The CEO shall be the chief executive officer of the Corporation. He or she shall be responsible for the day-to-day ongoing activities of the Corporation and shall have such other duties as may be delegated or assigned to him or her by the chair. The CEO may enter into and execute in the name of the Corporation contracts or other instruments not in the regular course of business that are authorized, either generally or specifically, by the Board.

Section 3. Corporate Secretary. The Secretary shall maintain the roster of Members of the Corporation, shall cause notices of all meetings to be served as prescribed in these Bylaws, shall keep or cause to be kept the minutes of all meetings of the Members and the Board, and shall have charge of the seal of the Corporation. The Secretary shall perform such other duties and possess such other powers as are incident to his or her office or as shall be assigned to him or her by the CEO. The CEO may select an Assistant Corporate Secretary at his or her discretion. The Assistant Corporate Secretary is not an Officer of the Corporation.

Section 4. Chief Financial Officer. A Chief Financial Officer shall have custody of the funds and securities of the Corporation, shall keep or cause to be kept regular books of account for the Corporation and shall have the duties normally assigned to a treasurer of a corporation. The Chief Financial officer shall perform such other duties and possess such other powers as are incident to his or her office or as shall be assigned to him or her by the CEO.

Section 5. Other Officers. The CEO may select such other Officers as he or she deems appropriate, subject to ratification by the Board. Any such Officer shall perform such other duties and possess such powers as are incident to his or her office or as shall be assigned to him or her by the CEO.

ARTICLE VIII.
MEMBER REPRESENTATIVES COMMITTEE

Section 1. Purpose of Member Representatives Committee. The Corporation shall have a "Member Representatives Committee" that shall provide advice and recommendations to the Board with respect to: annual budgets, business plans and funding mechanisms of the Corporation; the development of Regional Reliability Standards and Regional Variances in accordance with Texas RE's process; other matters relevant to reliability of the ERCOT Bulk Power System; and other matters pertinent to the purpose and operations of the Corporation. The Member Representatives Committee shall provide its advice and recommendation to the Board through its chair and the vice chair, who also serve as the Affiliated Directors on the Board. The Member Representatives Committee may create subcommittees, task forces, or working groups ("subcommittees") as it deems appropriate to study or discuss selected technical or compliance matters, provide a forum for the review and discussion of current and proposed Reliability Standards, and to make recommendations to the Board as requested or required by the Board or as deemed appropriate to its purpose by the Member Representatives Committee. Because it is elected by the Members of the Corporation and not appointed by the Board, the Member Representatives Committee shall not be a standing committee of the Board of Directors of the Corporation, but is authorized to provide advice and recommendations directly to the Board, through its elected chair and vice chair.

Section 2. Composition of the Member Representatives Committee. The Member Representatives Committee shall consist of two representatives from each Sector to serve two-year terms and will select a chair and vice chair for the Member Representatives Committee to serve two-year terms. The representatives of each Sector shall be officers, employees, or directors of Members in that Sector (or the Member's parent, subsidiary, or other Affiliate); provided however, except for a Sector that has only one Member, only one officer, employee, or director of a Member in a Sector (or the Member's parent, subsidiary, or other Affiliate) may be a representative from that Sector. The Board may by resolution create additional non-voting positions on the Member Representatives Committee on its own initiative or at the written request of any group of Members of the Corporation that believes its interests are not adequately represented on the Member Representatives Committee. There shall be no limit on the number of terms that an officer, employee, or director of a Member (or the Member's parent, subsidiary, or other Affiliate), may serve on the Member Representatives Committee.

Section 3. Election of Representatives of the Member Representatives Committee. Unless a Sector adopts an alternative election procedure, the election of representatives from each Sector to the Member Representatives Committee, and any election to fill a vacancy, shall be conducted in accordance with the following process, which shall be administered by the Secretary of the Corporation:

(a) During the period beginning no more than ninety (90) days and ending no less than fifteen (15) days prior to an annual meeting, or beginning no more than forty-five (45) days and ending no less than fifteen (15) days prior to a special election to fill a vacancy on the Member Representatives Committee, nominations may be submitted for candidates for election to the Member Representatives Committee. A nominee for election as a Sector representative must be an officer, employee, or director of a Member in that Sector (or the Member's parent, subsidiary, or other Affiliate). No more than one nominee who is an officer, employee, or director of a Member (or the Member's parent, subsidiary, or other Affiliate) may stand for election in any single Sector; if more than one officer, employee, or director of a Member (or the Member's parent, subsidiary, or other Affiliate) is nominated for election from a Sector, the Member shall designate which such nominee shall stand for election. The election of representatives shall be conducted over a period of ten (10) days using an electronic process approved by the Corporate Secretary.

(b) Each Member in a Sector shall have one vote for each Representative to be elected from the Sector in that election and may cast no more than one vote for any nominee. The nominee receiving the highest number of votes in each Sector shall be elected to one Representative position to be filled from that Sector and the nominee receiving the second highest number of votes shall be elected as the second Representative position for that Sector. To be elected on the first ballot, a nominee must receive a number of votes equal to a simple majority of the Members in the Sector casting votes in the election. If no nominee in a Sector receives a simple majority of votes cast in the first ballot, a second ballot shall be conducted which shall be limited to the number of candidates receiving the three (3) highest vote totals on the first ballot. The nominees receiving the two highest totals of votes on the second ballot shall be elected to the Representative positions for the Sector.

(c) A Sector may adopt an alternative procedure to the foregoing to nominate and elect its Representatives to the Member Representatives Committee if the alternative procedure is approved by vote of at least two-thirds of the Members in the Sector, provided, however that any alternative procedure must be reviewed and approved by the Board.

(d) A Sector may elect an Alternate to serve in place and at the convenience of the Sector's Member Representatives Committee Representative(s) in the event a Member

Representatives Committee Representative cannot attend a Member Representatives Committee meeting.

Section 4. Chair and Vice Chair of the Member Representatives Committee. After the selection of its Representatives, the Member Representatives Committee shall select a chair and vice chair from among its voting Representatives by majority vote to serve during the upcoming two-year term and be the Affiliated Directors on the Board. The selected chair and vice chair may not be representatives of the same Sector and may not concurrently serve on the Board of ERCOT ISO. The Board shall be notified of the selection of the chair and vice chair, but the selection will not be subject to approval of the Board. The chair is responsible for ensuring that minutes of the meetings are properly maintained and made available to the public, but the chair may delegate this responsibility to the vice chair or to another Representative of the Member Representatives Committee who may be designated as secretary of the Member Representatives Committee.

Section 5. Vacancies on the Member Representatives Committee. In the event that any Representative of the Member Representatives Committee ceases to serve as a Representative of the Member Representatives Committee as a result of his or her death, resignation, retirement, disqualification, removal, or other cause, the Members in the Sector of which such Representative was a representative shall elect, as soon thereafter as reasonably practicable, and in accordance with the procedures in this Article VIII, a new Representative to replace the Representative of the Member Representatives Committee who ceased to serve. For those Sectors that have elected an Alternate, the Alternate will fill a vacancy left by the Sector's Member Representative until a new Sector Member Representative is elected by the Sector.

Section 6. Meetings of the Member Representatives Committee. The Member Representatives Committee will plan and hold quarterly meetings, at a time and place determined by the Member Representatives Committee, normally shortly before the regular meetings of the Board, and posted on the Corporation's website. Except for closed session meetings specifically allowed by this Section, all meetings shall be open to the public.

(a) Notice to the public of the dates, places, and times of meetings of the Member Representatives Committee and any subcommittees, and all non-confidential material provided to the Representatives on the Member Representatives Committee or any subcommittees, shall be posted on the Corporation's website at approximately the same time that notice or such material is given to the Member Representatives Committee, which will normally be at least five (5) business days prior to the scheduled meeting. Meetings of the Member Representatives Committee and subcommittees shall be open to the public, subject to reasonable limitations due to the availability and size of meeting facilities; provided, that the Member Representatives Committee and subcommittees may meet in or adjourn to closed session to discuss matters of a confidential nature, including but not limited to confidential planning information, critical infrastructure information, or commercially sensitive information of the Corporation or any other entity. Participation in a meeting of the Member Representatives Committee or subcommittee may be accomplished through use of a communications system by which all persons participating in the meeting are able to hear each other.

(b) Special meetings may be called for any purpose or purposes by the chair of the Member Representatives Committee or by any three (3) Representatives of the Member Representatives Committee, which number shall include representatives from at least three Sectors, and require notice given to all Representatives of the Member Representatives Committee not less than seven (7) days prior to the date of the meeting. Such notice shall specify

the time, date, place, and purpose or purposes of the meeting and may be given by telephone, email, or other electronic media, or by express delivery.

(c) The Member Representatives Committee shall effectively coordinate with the employees of the Corporation and adopt procedural rules for the voting for Representatives, scheduling of meetings, and public posting of required meeting information and minutes. The chair or vice chair of the Member Representatives Committee shall provide all meeting agendas, material, minutes and other information required or desired to be posted on the Corporation's website to appropriate Corporation employees at least one (1) business day prior to the time such information should be posted.

Section 7. Action Without a Meeting of Members. Any action, required or permitted to be taken at a meeting of the Member Representatives Committee, may be taken without a meeting if the proposed action is posted to all Committee Members via direct email and consented to in writing by a majority of the Representatives. The voting in such a circumstance shall be performed in writing, including via email or other electronic means. The Representatives shall receive written notice of the results within ten (10) days of the action vote, and all written responses of the Representatives shall be retained as a corporate record. The results of such voting will be reported at the next in-person Member Representatives Committee meeting.

Section 8. Waivers of Notice of Meetings of the Member Representatives Committee and Meeting Adjournments. Notice of a meeting of the Member Representatives Committee need not be given to any member of the Member Representatives Committee who waives notice, in writing, before, during, or after the meeting. The attendance of any Committee member at a meeting, in person or by proxy, without protesting prior to the conclusion of the meeting the lack of proper notice of such meeting, shall constitute waiver of notice of the meeting by such Committee Member. When a meeting of the Member Representatives Committee is adjourned to another time or place, it shall not be necessary to give notice of the adjourned meeting if the time and place to which the meeting is adjourned are announced at the meeting at which the adjournment is taken, and if at the adjourned meeting only such business is transacted as might have transacted at the original meeting.

Section 9. Quorums and Voting for Meetings of the Member Representatives Committee. The quorum necessary for the transaction of business at meetings of the Member Representatives Committee shall be the presence, in person or by proxy, of two-thirds of the voting Representatives on the Member Representatives Committee entitled to attend. Each voting member of the Member Representatives Committee shall have one (1) vote on any matter coming before the Member Representatives Committee that requires a vote. Except as otherwise expressly provided in the Corporation's Certificate of Formation, these Bylaws or applicable law, actions by members of the Member Representatives Committee shall be approved upon receipt of the affirmative vote of a majority of the voting members of the Member Representatives Committee present (by means of any communications system by which all persons participating in the meeting are able to hear each other) and voting at any meeting at which a quorum is present.

Section 10. Alternates and Proxies. Member Representatives may designate another Member Representative or an employee of the Member Representative's organization (or the Member's parent, subsidiary, or other Affiliate) as a proxy if both the Member Representative and the Sector Alternate are unable to attend a Member Representatives Committee meeting. A member of the Member Representatives Committee may give a proxy only to a person who is an officer, employee, or director of a Member, registered in the same Sector (or the Member's parent, subsidiary, or other Affiliate).

Section 11. Other Procedures of the Member Representatives Committee. Except as to any matter as to which the procedure to be followed by the Member Representatives Committee is expressly set forth in these Bylaws, the Member Representatives Committee may adopt such additional procedures, not inconsistent with these Bylaws, as it deems appropriate, subject to review and approval by the Board.

ARTICLE IX.
OTHER COMMITTEES AND SUBCOMMITTEES

Section 1. Other Committees and Subcommittees of the Corporation. The Board may by resolution create committees and subcommittees of the Corporation to provide advice to the Board. The Board will appoint the members of such committees, subcommittees, and task forces that are representative of Members, and other interested parties, as appropriate, that provide for balanced decision-making and that include persons with sufficient technical knowledge and experience. All committees and subcommittees shall have such scope and duties as determined by the Board.

ARTICLE X.
BUDGETS AND FUNDING

Section 1. Compensation of the Board and Member Representatives Committee.

(a) The Board shall have a Director compensation committee (the "Director Compensation Committee") to have the right to evaluate and fix from time to time, by simple majority vote, the amount of the annual retainer fee or other compensation to be paid to the Independent Directors for their services to the Corporation, including any fees to be paid for each meeting of the Board or any Board committee attended by an Independent Director. The Director Compensation Committee will evaluate the fee or other compensation annually to ensure that Director compensation is appropriate. The Director Compensation Committee shall consist of two (2) Independent Directors that are not currently serving as Board Chair and Vice Chair (unless there is an Independent Director vacancy, in which case the Board Vice Chair will serve on the Committee until the vacancy is filled), two (2) Affiliated Directors, and the CEO. The Board Chair shall appoint an Independent Director as the Chair of the Director Compensation Committee. Meetings of the Director Compensation Committee are not required to be publicly posted.

(b) No compensation shall be paid to any Management Director, Affiliated Director, or *ex officio* Director for his or her services on the Board, other than the compensation paid to the Management Director for services as CEO of the Corporation. No compensation shall be paid by the Corporation to any member of the Member Representatives Committee for his or her services on the Member Representatives Committee.

(c) Independent Directors shall be entitled to be reimbursed their reasonable out-of-pocket expenditures for attending meetings and conducting the business of the Corporation.

Section 2. Preparation and Adoption of Annual Budget, Business Plan, and Funding Mechanism. The Board shall require the CEO to prepare for Board approval an annual business plan and budget for the administrative and other expenses of the Corporation, including the expenditures for the fiscal year for any material special projects undertaken by the Corporation and reasonable and proper reserves and provisions for contingencies, in accordance with all NERC and FERC requirements. The annual business plan, budget and funding mechanism of

the Corporation shall be for a fiscal year commencing on January 1 and ending on December 31. Each annual business plan, budget, and funding mechanism shall be approved by the Board at a regular meeting or a special meeting of the Board duly called for that purpose. The Board shall approve each annual business plan, budget, and funding mechanism at a time that allows for timely submittal of the approved annual business plan, budget, and funding mechanism to the applicable regulatory authorities.

Section 3. Comments During Preparation of Annual Business Plan and Budget. In preparing the annual business plan and budget, the Board shall require that the CEO post a draft business plan and budget for review and comment by the Members of the Corporation, the Member Representatives Committee, and the standing committees of the Corporation for at least five (5) business days prior to the date of the meeting of the Board at which the annual business plan and budget is to be adopted.

Section 4. Modified or Supplemental Budgets. During the course of a fiscal year, the Board may modify any approved budget or develop and approve a supplemental budget if determined by the Board to be necessary due to such factors as a shortfall in revenues of the Corporation from projected levels, incurred or anticipated expenditures, duties, or new projects not provided for in the annual budget, or such other factors as in the judgment of the Board warrant modification of the budget for the fiscal year or development of a supplemental budget. In preparing a modified or supplemental budget, the Board shall follow the provisions of this Article X, Section 4 to the extent practicable in the judgment of the Board in light of the urgency of the circumstances necessitating preparation and approval of the modified or supplemental budget. Each modified or supplemental budget shall be approved by the Board at a regular meeting or a special meeting of the Board duly called for that purpose.

Section 5. Submission of Annual Business Plans and Budgets to the Regulatory Authorities. Each annual budget, annual business plan, and annual, modified, or supplemental budget approved by the Board shall be submitted by the Corporation to the ERO and any applicable regulatory authorities for approval in accordance with its regulations, and shall not be effective until approved by the applicable regulatory authorities. If ordered to modify or remand an annual budget, business plan, or annual, modified, or supplemental funding mechanism, the Board shall promptly following such order adopt such modifications to the business plan, budget, or funding mechanism as are required or directed by the order of the ERO and any applicable regulatory authority.

ARTICLE XI.
AMENDMENTS TO THE BYLAWS

Section 1. Amendments to the Bylaws. These Bylaws may be altered, amended, or repealed by action of the Membership, as set forth below. Any alteration, amendment, repeal or adoption of Bylaws shall be subject to any applicable requirements for filing with or approval by the ERO or any other applicable regulatory authority. These Bylaws may be altered, amended, or repealed as follows:

(a) Suggested amendments to these Bylaws may be made through the submissionof the proposed amendments, including any necessary supporting documents, to the Corporate Secretary.

(b) The Corporate Secretary shall place the proposal on the agenda for a Board meeting, or if the Board has designated a standing committee with authority to review

proposed amendments and make a recommendation to the Board, the Corporate Secretary shall place the proposal on that committee's next scheduled meeting agenda.

(c) If the proposal is approved by an act of the Board as set forth in Article VI, Section 3, the Board shall place the proposal on the agenda of the next Annual Meeting of the Corporate Members unless the Board in its discretion calls a Special Meeting of the Corporate Members to vote on the proposal or determines to seek Membership approval without a meeting as provided in Article V, Section 4.

(d) If the proposal is not approved by the Board, the Members of the Corporation may call a meeting, pursuant to Article V, Section 1(b), for the purpose of voting on a proposal not approved by the Board. Any such proposal must be approved by a vote of five of the six Sectors at a meeting of Members called for that purpose or by written consent of five of the Sectors, where the number of votes for and against the proposed alteration, amendment, repeal or adoption of Bylaws shall be determined in accordance with Article V, Section 2.

ARTICLE XII.
INDEMNIFICATION; PROCEDURE; DISSOLUTION

Section 1. Indemnification. The Corporation shall indemnify each person who at any time shall serve, or shall have served, as an officer, Director, employee, or other corporate agent of the Corporation, is or was serving at its request as a director, officer, partner, venturer, proprietor, employee, agent or similar functionary of another foreign or domestic corporation, partnership, joint venture, sole proprietorship, trust, employee benefit plan or other enterprise ("Indemnified Parties"), to the full extent from time to time permitted by the Texas Business Organizations Code and other applicable law. Such right of indemnification shall inure to the benefit of the legal representative of any such Indemnified Party. The foregoing indemnification shall be in addition to, and not in restriction or limitation of, any privilege or power that the Corporation may have with respect to the indemnification or reimbursement of its Indemnified Parties. The Corporation shall also pay or advance reasonable expenses incurred by an Indemnified Party in connection with a proceeding in advance of the final disposition of the proceeding upon receipt of a written affirmation by the Indemnified Party of a good faith belief that the standard of conduct necessary for indemnification under this Article XII and the Texas Business Organizations Code has been met and a written undertaking by or on behalf of the officer, Director, or other corporate agent to repay the amount if it shall be ultimately determined that the Indemnified Party was not entitled to be indemnified by the Corporation.

Section 2. Parliamentary Rules. In the absence of and to the extent not inconsistent with specific provisions in these Bylaws, meetings or other actions pursuant to these Bylaws shall be governed by procedures that the Board may, from time to time, establish by resolution.

Section 3. Dissolution. Upon dissolution of the Corporation, in accordance with the Certificate of Formation, the remaining assets of the Corporation after payment of debts shall be distributed in the manner determined by the Board, provided that, (i) no part of the assets shall be distributed to any Director of the Corporation, and (ii) the distribution of assets shall be consistent with the requirements of Section 501(c)(3) of the United States Internal Revenue Code of 1986, as amended.

ARTICLE XIII.
CONFLICTS OF INTEREST

Section 1. Conflicts of Interest.

(a) Each Director shall have an affirmative duty to disclose to the Board or committee (as the case may be) any actual or potential conflicts of interest of the Director that arise during his or her tenure as a Director where, and to the extent that, such conflicts or potential conflicts directly or indirectly affect any matter that comes before the Board. A Director with a direct or potentially conflicting interest in a matter shall recuse himself from deliberations and actions on the matter in which the conflict arises and shall abstain on any vote on the matter and not otherwise participate in a decision on the matter. Any disclosure of a potential conflict of interest by a Director shall be noted in the minutes of the Board meeting at which the direct interest is disclosed. Mere attendance at the meeting, without participating in discussion of the issue raising the potential conflict, shall not constitute participation.

(b) The Corporation may not make any loan to a Director, committee member or officer of the Corporation. A Member, Director, officer, or committee member of the Corporation may not lend money to, or otherwise transact business with, the Corporation except as otherwise provided by these Bylaws, the Certificate of Formation, and applicable law. A related party transacting business with the Corporation has the same rights and obligations relating to those matters as other persons transacting business with the Corporation, provided the related party nature of the transaction is known to the Board. The Corporation may not borrow money from, or otherwise transact business with, a Member, Director, officer, or committee member of the Corporation unless the transaction is described fully in a legally binding instrument, is in the Corporation's best interests, and is on terms no less favorable to the Corporation than could be obtained in an arms-length transaction. The Corporation may not borrow money from, or otherwise transact business with, a Member, Director, officer, or committee member of the Corporation without full disclosure of all relevant facts and without the Board's approval, not including the vote of any person having a personal interest in the transaction.

Section 2. Prohibited Acts. No Member, Director, officer, or committee member of the Corporation may do any of the below-listed prohibited acts. Engaging in these prohibited acts may lead to sanction, suspension, expulsion or termination after a hearing as described in these Bylaws. The prohibited acts include the following:

(a) Do any act in violation of these Bylaws.

(b) Do any act in violation of a binding obligation of the Corporation except with the Board's prior approval.

(c) Do any act with the intention of harming the Corporation or any of its operations.

(d) Receive an improper personal benefit from the operation of the Corporation.

(e) Use the Corporation's assets, directly or indirectly, for any purpose other than carrying on the Corporation's business.

(f) Wrongfully transfer or dispose of Corporation property, including intangible property such as goodwill.

(g) Use the Corporation's name (or any substantially similar name) or any trademark or trade name adopted by the Corporation, except on behalf of Corporation in the ordinary course of its business or as a reference to the Corporation or its region.

(h) Disclose any of Corporation's or Members' business practices, trade secrets, or any other confidential or proprietary information not generally known to the business community to any person not authorized to receive it.

Section 3. Loans and Guarantees. Neither participation in the activities of the Corporation nor any provision of these Bylaws or of the Certificate of Formation shall be deemed to constitute a pledge or loan of the credit of any Member for the benefit of the Corporation or a guarantee by any Member of any obligation of the Corporation.

ARTICLE XIV.
BOOKS AND RECORDS; AUDIT; FISCAL YEAR

Section 1. Access to Books and Records. All Members of the Corporation will have access to the books and records of the Corporation, including financial statements and budgets; however, the Board shall establish procedures by which a Member, upon written demand stating the purpose of the demand may examine and copy the books and records of the Corporation. If necessary to protect the confidential information of the Corporation, a Member requesting examination of any of the Corporation's non-public books and records will be required to sign a confidentiality and non-disclosure agreement before viewing such information. The procedures shall include policies that provide reasonable protection against the unnecessary disclosure of information related to individual employees, including their compensation.

Section 2. Audit. At least annually, an audit of the financial statements of the Corporation shall be performed by the Auditor approved by the Board. The Auditor's opinion and the audited financial statements will be made available to all Members as described in Article XIV, Section 1.

Section 3. Fiscal Year. The fiscal year of the Corporation shall be from January 1 through the following December 31, unless otherwise established by resolution of the Board.

ATTACHMENT 2

Amended Bylaws

Texas Reliability Entity, Inc. – Redline

AMENDED AND RESTATED BYLAWS

OF

TEXAS RELIABILITY ENTITY, INC.

(A Texas Non-Profit Corporation)

Approved by Membership – ~~November 16, 2016 and December 23, 2016~~ December 17, 2018

Approved by Federal Energy Regulatory Commission – ~~May 30, 2017~~

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ARTICLE I.
DEFINITIONS

Section 1. Definitions. The capitalized terms used in these Bylaws of Texas Reliability Entity, Inc. (the "Corporation" or "Texas RE"), shall have the meanings set forth below, or if not set forth below, shall have the meanings given them in the NERC Rules of Procedure.

(a) "Affiliate" means any entity controlling, controlled by or under common control with the entity under consideration, and includes any entity (i.e., any commercial enterprise) in any of the following relationships: (i) an entity that directly or indirectly owns or holds at least five percent of the voting securities of another entity, (ii) an entity in a chain of successive ownership of at least five percent of the voting securities of another entity, (iii) an entity which shares a common parent with or is under common influence or control with another entity or (iv) an entity that actually exercises substantial influence or control over the policies and actions of another entity. Evidence of influence or control shall include the possession, directly or indirectly, of the power to direct or cause the direction of the management and/or policies and procedures of another, whether that power is established through ownership or voting of at least five percent of the voting securities or by any other direct or indirect means. In cases where the level of control or influence is disputed, the Board shall have discretion to determine whether or not the entities are Affiliates of one another. Membership in Texas RE shall not create an affiliation with Texas RE.

(b) "Board" means the Board of Directors of the Corporation.

(c) "Bulk Power System" or "BPS" means facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof) and facilities generating electric energy as needed to maintain transmission system reliability, but does not include facilities used in the local distribution of electricity.

(d) "Delegated Authority" means the authority delegated by NERC to the Corporation to propose and enforce NERC Reliability Standards and perform other reliability-related activities in the ERCOT region under the Delegation Agreement executed by NERC and the Corporation and approved by the Federal Energy Regulatory Commission, pursuant to Section 215 of the Federal Power Act (16 U.S.C. §824o).

(e) "Delegation Agreement" means the agreement between the Corporation and NERC and approved by FERC, which describes the Delegated Authority and may be amended from time to time.

(f) "Electric Reliability Organization" or "ERO" means the organization that is certified by FERC pursuant to Section 39.3 of its regulations, and has received recognition by appropriate regulatory authorities in Canada and Mexico, as applicable, to establish and enforce Reliability Standards for the Bulk Power Systems of the respective countries and that has entered into a delegation agreement with the Corporation pursuant to which the Electric Reliability Organization delegates enforcement authority for Reliability Standards for the Bulk Power System in the ERCOT region. NERC was certified as the ERO on July 20, 2006.

(g) "ERCOT region" means the geographic area and associated transmission and distribution facilities that are not synchronously interconnected with electric utilities operating outside the jurisdiction of the Public Utility Commission of Texas.

(h) "FERC" means the Federal Energy Regulatory Commission.

(i) "Independent Director" means a person who is not (a) an officer or employee of the Corporation; (b) a NERC Registered Entity or Member or an officer, director, or employee of a Member of the Corporation; or (c) an officer, director, or employee of any company or entity that would reasonably be perceived as having a direct financial interest in the outcome of Board decisions or having a relationship that would interfere with the exercise of independent judgment in carrying out the responsibilities of a Director, as more specifically described in Article IV of these Bylaws.

(j) "Member" means a member of the Corporation pursuant to Article III of these Bylaws.

(k) "NERC" means North American Electric Reliability Corporation, the entity certified by FERC as the ERO on July 20, 2006.

(l) "NERC Rules of Procedure" means the Rules of Procedure that are adopted by NERC and approved by FERC.

(m) "PUCT" means the Public Utility Commission of Texas.

(n) "OPUC" means the Texas Office of Public Utility Counsel.

(o) "Originally Elected Independent Director" means a Director approved by the membership on June 2, 2010, in the first election of Texas Reliability Entity, Inc. Independent Directors.

(p) "Regional Entity" means an entity with a Delegation Agreement with NERC, as ERO~~, including the following organizations, in addition to Texas Reliability Entity: Florida Reliability Coordinating Council (FRCC), Midwest Reliability Organization (MRO), Northeast Power Coordinating Council (NPCC), ReliabilityFirst Corporation (RF), Southeastern Electric Reliability Council (SERC), Southwest Power Pool (SPP), and Western Electricity Coordinating Council (WECC)~~.

(q) "Regional Reliability Standard" means a standard or variance for the ERCOT region that is proposed and approved in accordance with the Texas RE Standards Development Process and either, (i) sets more stringent reliability requirements than a national Reliability Standard, or (ii) covers matters not covered by a national Reliability Standard.

(r) "Registered Entity" means an entity that is registered with NERC and listed on the NERC Compliance Registry (available at www.nerc.com).

(s) "Reliability Standard" means a requirement to provide for Reliable Operation of the Bulk ~~-~~Power System, ~~–~~which is approved by NERC and FERC, pursuant to Section 215 of the Federal Power Act and all amendments thereto. This term includes requirements for the operation of existing Bulk ~~-~~Power System facilities, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary to provide for Reliable Operation of the Bulk Power System.

(t) "Reliable Operation" means operating the elements of the Bulk Power System within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of the Bulk Power System will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.

(u) "Sector" means a group of Members of the Corporation that are Bulk Power System owners, operators, or users, as defined in Article III, Section 4 of these Bylaws. Each Sector shall constitute a class of Members for purposes of Chapter 22 (Nonprofit Corporations) of the Texas Business Organizations Code.

ARTICLE II.
PURPOSE

Section 1. General Purpose. The purpose of the Corporation is to preserve and enhance electric reliability in the ERCOT region. In furtherance of this goal, the Corporation will:

(a) Perform Reliability Standards development, compliance monitoring, compliance enforcement, and other related activities as a Regional Entity, pursuant to 16 U.S.C. §824o, in accordance with the Corporation's Delegation Agreement with NERC;

(b) Carry out other activities as set forth in the Delegation Agreement, the NERC Rules of Procedure, or as otherwise required or requested by NERC, in support of the Delegated Authority, including but not limited to organization registration and certification, reliability assessment and performance analysis, training and education, and situational awareness and infrastructure security; and

(c) Engage in any other lawful act or activity that is not in conflict with the Corporation's duties as a Regional Entity and for which non-profit corporations may be organized under the Texas Business Organizations Code.

Section 2. Non-Profit Corporation. The Corporation is a Texas non-profit corporation.

Section 3. Geographic Area. The Corporation will perform its operations primarily within the ERCOT region.

ARTICLE III.
MEMBERSHIP

Section 1. Members. The Corporation is a membership corporation. Membership in the Corporation is voluntary and is open only to any entity that is a user, owner or operator of the ERCOT region Bulk Power System, registers with the Corporation as a Member, maintains its registration in accordance with this Article III, and complies with the other conditions and obligations of membership specified in these Bylaws. All Members must qualify and be registered in one of the Sectors defined in Article III, Section 4. Membership in the Corporation is not a condition to participating in the development or consideration of proposed Regional Standards.

Section 2. Registration as a Member. Any entity that is eligible to be a Member of the Corporation in accordance with Article III, Section 1 may become a Member by completing and submitting to the Corporation a membership registration on a form prescribed by the Corporation. The Member shall designate one representative and an alternative representative with authority to receive notices, cast votes, and execute waivers and consents on behalf of the Member. The Corporate Secretary shall maintain a current roster of the Members of the Corporation including each Member's designated representative and alternative representative. All Members shall be required to renew or reaffirm their registrations annually. The Corporate

Secretary may remove any Member from the roster that has not submitted a registration renewal or reaffirmation by a date established by the Corporation.

Section 3. Obligations and Conditions of Membership.

(a) Members must agree to promote, support, and comply with Reliability Standards, and assist the Corporation in its compliance with the terms and provisions of the Corporation's Delegation Agreement with NERC. Each Member shall agree, in writing, to accept the responsibility to comply with policies of NERC and the Corporation as set forth in their respective certificates of formation, bylaws, rules of procedure, and Reliability Standards, as applicable, as from time to time adopted, approved, or amended.

(b) As an additional condition of membership in the Corporation, each Member shall be required to execute an agreement with the Corporation, in a form to be specified by the Corporation, that such entity will hold all Directors, officers, employees, and agents of the Corporation, as well as volunteers participating in good faith in the activities of the Corporation, harmless for any injury or damage caused by any act or omission of any director, officer, employee, agent, or volunteer in the course of performance of his or her duties on behalf of the Corporation, other than for willful acts of misconduct.

(c) Consistent with applicable laws and regulations, Members must share nonproprietary information at the Corporation's request as necessary for the furtherance of the Corporation's activities and consistent with NERC, PUCT, or any other applicable rules relating to confidentiality.

Section 4. Membership Sectors. Each Member shall elect to be assigned to one of the following membership Sectors:

(a) **System Coordination and Planning**: An entity that is registered with NERC as a Reliability Coordinator (RC), Balancing Authority (BA), Planning Authority (PA), or Resource Planner (RP).

(b) **Transmission and Distribution**: An entity that is registered with NERC as a Transmission Owner (TO), Transmission Planner (TP), Transmission Service Provider (TSP), Distribution Provider (DP), and/or Transmission Operator (TOP) and is not a Cooperative or Municipal Utility.

(c) **Cooperative Utility**: An entity that is (a) a corporation organized under Chapter 161 of the Texas Utilities Code or a predecessor statute to Chapter 161 and operating under that chapter; or (b) a corporation organized as an electric cooperative in a state other than Texas that has obtained a certificate of authority to conduct affairs in the State of Texas~~;~~ or (c) a cooperative association organized under Chapter 251 of the Texas Business Organizations Code ~~Tex. Rev. Civ. Stat. 1396-50.01 or a predecessor to that statute and operating under that statute~~ and is registered with NERC for at least one reliability function.

(d) **Municipal Utility**: A municipally owned utility as defined in Public Utility Regulatory Act, Tex. Util. Code §11.003 and is registered with NERC for at least one reliability function.

(e) **Generation**: An entity that is registered with NERC as a Generator Owner (GO) or Generator Operator (GOP).

(f) **Load-Serving and Marketing**: An entity that secures wholesale transmission service or is engaged in the activity of buying and selling of wholesale electric power in the ERCOT region on a physical or financial basis, or qualifies under any newly defined NERC reliability function for demand response.

Section 5. Participation.

(a) There is only one level of Membership, and no company or entity may simultaneously hold more than one Membership.

(b) Members must qualify in and join a Sector.

(c) A Member that is eligible for more than one Sector may join only one Sector and it must be the most appropriate Sector for its business. Any disputes regarding appropriateness of a Member's Sector will be decided by a majority vote of the Board.

(d) A company or entity that is an Affiliate of a Member may hold a separate membership in a different Sector if the companies are separate legal entities.

(e) A Member must continue to vote in the same Sector for a minimum of the remainder of the membership year in which it becomes a Member or until it is no longer eligible to remain in such Sector, and it must give notice to the Corporate Secretary when it elects or is required to change Sectors.

(f) The Corporate Secretary may review the Sector qualification of any Member and upon a determination that a Member does not qualify for membership in a particular Sector, may require the Member to change Sectors or may terminate their membership.

(g) A Member that is no longer eligible or that is not in good standing may not vote on any matters that require membership.

Section 6. Membership Fees. There is no Membership Fee to join the Corporation.

Section 7. Term of Membership. Membership in the Corporation must be renewed or reaffirmed on an annual basis and will only be retained as long as a Member meets its respective qualifications, obligations, and conditions of membership as set forth in these Bylaws.

Section 8. Disciplinary Action. A Member or Member representative may be sanctioned, suspended, or expelled pursuant to a procedure that is fair and reasonable and is carried out in good faith. The Board will establish a procedure to sanction, suspend, or expel a Member that includes notice to the Member and exercise of appropriate due process procedures, and allows for a determination by the Board in its sole discretion that in its judgment the Member has violated its obligations and responsibilities to the Corporation.

Section 9. Resignation. Any other provision of these Bylaws notwithstanding, any Member may withdraw from participation in the activities of the Corporation at any time upon written notice to the Secretary of the Corporation, whereupon it shall cease to be a Member, and its representatives shall cease to be entitled or obligated to participate in the activities of the Board or any activities requiring membership.

Section 10. Reinstatement. A former Member, except a Member subject to Disciplinary Action under Section 8, may submit a membership application form to rejoin the Corporation as a Member. A Member disciplined under Section 8 may submit a written request for reinstatement of Membership. The request for reinstatement will be considered by the Board, and will be granted or denied within the sole discretion of the Board.

ARTICLE IV.
BOARD OF DIRECTORS

Section 1. Board of Directors. The business and affairs of the Corporation shall be managed by the Board. The Board shall consist of (i) four (4) Independent Directors who are nominated and elected in accordance with the requirements and procedures specified in this Article IV (the "Independent Directors"); (ii) the Chairman of the PUCT or another PUCT Commissioner designated by the Chairman, as an *ex officio* non-voting member; (iii) Texas Public Counsel, from OPUC ~~(or another employee of OPUC designated by Texas Public Counsel),~~ as an *ex officio* non-voting member, representing the interests of residential and small commercial electricity consumers; (iv) the CEO of the Corporation as a voting member (the "Management Director"); (v) the chair of the Member Representatives Committee as a voting member; and (vi) the vice chair of the Member Representatives Committee as a voting member. The Directors who are the chair and vice chair of the Member Representatives Committee will be collectively referred to herein as "Affiliated Directors." ~~Each Director, including the Affiliated Directors and excluding the non-voting members of the Board, shall have one (1) vote on any matter brought before the Board for a vote.~~ All Directors are expected to serve the public interest and to represent the reliability concerns of the entire ERCOT region Bulk Power System.

Section 2. Independent Directors. The Independent Directors shall be elected, shall have the qualifications specified, and shall serve in the manner provided in this Section.

(a) Qualifications:

(1) Experience in one or more of these fields: senior corporate leadership; professional disciplines of finance, accounting, engineering, bulk power systems, or law; regulation of utilities; and/or risk management.

(2) Independence of any NERC Registered Entity. Requirements of independence include but are not limited to the following:

(i) Independent Directors and the spouse, mother, father, sibling, or dependent, and any spouse of mother, father, or sibling and including any step and adoptive parents, siblings or children, and household members of Independent Directors and their spouses shall not have current or recent status (within the last two years) as a director, officer, or employee of an ERCOT region NERC Registered Entity.

(ii) Independent Directors and immediate family (any spouse or dependent) and household members of Independent Directors shall not have current status as a director, officer, or employee of a non-ERCOT region NERC Registered Entity.

(iii) Independent Directors and immediate family and household members of Independent Directors shall not have direct business relationships, other than retail customer relationships, with any NERC Registered Entity.

(iv) Independent Directors and immediate family and household members of Independent Directors shall not own stocks or bonds of NERC Registered Entities or their affiliates. To the extent that an Independent Director or his or her spouse, dependent child, or any other household member owns stocks or bonds of NERC Registered Entities, these must be divested or placed in a blind trust prior to being seated on the Board. Ownership in broadly diversified mutual funds or similar funds, which may include stocks or bonds of NERC Registered Entities or their affiliates, is not prohibited.

(v) Independent Directors shall not have any relationship that would interfere with the exercise of independent judgment in carrying out the responsibilities of a Board member, including the Delegated Authority.

(vi) Other criteria as approved by the Board.

(b) Term. The term for Independent Directors shall be staggered three year terms. An Independent Director may be elected for up to three consecutive terms. For the Originally Elected Independent Directors, two positions will have three-year terms, one position will have a two-year term, and one position will have a one-year term, and these terms shall not be counted for purposes of term limits. The term for the Affiliated Directors ~~who are chair and vice chair of the Member Representatives Committee~~ shall ~~be two years~~coincide with their ~~Affiliated Directors'~~ terms as chair and vice chair of the Member Representatives Committee. ~~, and t~~The terms of the *ex officio* Directors ~~will not expire~~terminate when the individual ceases to be Chairman of the PUCT (or the PUCT Chairman designates another Commissioner) or ceases to be Texas Public Counsel. If an Independent Director is elected to fill an unexpired term in the event of a vacancy, that term shall not be counted for purposes of term limits.

(c) Selection.

(1) The Board shall appoint, on an annual basis, or more frequently if needed in the event of a special election pursuant to this subsection, a nominating committee (the "Nominating Committee") to recommend candidates (i) to succeed the Independent Directors whose terms expire during the current year; (ii) to serve the remainder of the term of any Independent Director who ceased to serve as a Director subsequent to the last annual election of Directors; (iii) to serve as the Chair and Vice Chair on an annual basis; and (iv) to serve as CEO in the event of a vacancy. The Nominating Committee shall consist of two (2) Independent Directors whose terms do not expire during the current year and are not seeking re-election and one (1) Affiliated Director. The PUCT Chairman (or the PUCT Commissioner designated by the Chairman) may choose to participate on the Nominating Committee. The Board Chair shall appoint the Chair of the Nominating Committee. The Nominating Committee may retain an executive search firm to locate and present candidates to serve as Independent Directors with the required qualifications, as set forth in Article IV, Section 2(a) or to locate and present candidates to serve as CEO. Meetings of the Nominating Committee are not required to be publicly posted.

(2) The Nominating Committee shall select and nominate, by at least a two-thirds majority, qualified candidate(s) to serve as Independent Directors to present to the Membership for its approval. The Nominating Committee shall strive to ensure that the Board as a whole reflects expertise in the areas of technical electric operations and reliability, legal, senior corporate leadership, financial, risk

management, and regulatory matters, and familiarity with regional system operation issues in the ERCOT region.

(3) The Membership shall vote by Sector as described in Article V in favor or against the proposed Independent Director(s). A proposed Independent Director who is approved by a majority of the Sectors shall become an Independent Director.

(4) The Nominating Committee shall select and recommend to the Board, by at least a two-thirds majority, a qualified candidate to serve as CEO. The Directors may choose to participate in interviewing CEO candidates.

(d) Director Voting Weights. All voting Directors shall have a single vote each.

(e) Alternates and Proxies. Independent Directors may designate another Independent Director as a proxy if unable to attend a Board meeting. *Ex officio* Directors may designate an alternate representative who may attend public meetings in the absence of such Director. The chair and vice chair of the Member Representatives Committee may designate each other or may designate an Independent Director as their proxy if unable to attend a Board meeting. The CEO may designate an Independent Director as a proxy if unable to attend a Board meeting.

Section 3. Appointment of Management Director. The president and chief executive officer (CEO) of the Corporation shall serve as the Management Director of the Corporation, effective as of the date of his or her appointment by the Board as CEO of the Corporation in accordance with these Bylaws, to serve until such time that he or she ceases to hold the position of CEO. No action of the Members of the Corporation shall be required in connection with the appointment of the CEO as the Management Director of the Corporation.

Section 4. Chair and Vice Chair. Annually, the Board shall elect from the Board's membership, by resolution of the Board, a Chair and a Vice Chair. The Chair and Vice Chair shall each be one of the Independent Directors.

Section 5. Vacancies and Removal.

(a) Should any vacancy on the Board arise from the death, resignation, retirement, disqualification, or removal from office of any Director, or from any other cause, such vacancy shall be filled as follows:

(1) For an Independent Director, by the election of a new Independent Director at the next annual election of Directors to fill the remainder, if any, of the term of the departed Independent Director; provided, that the Board by resolution may in its discretion call a special election to fill any such vacancy for the remainder, if any, of the term of the departed Independent Director.

(2) For the Management Director, by the appointment of a new CEO or interim CEO to fill the vacancy.

(3) For an *ex officio* Director, by the appointment of a new PUCT Chair (or the Chair's designee) or the appointment of a new Texas Public Counsel ~~by whomever had the right to appoint such Director~~.

(4) For an Affiliated Director, by the election of a new chair or vice chair, as applicable, by the Member Representatives Committee.

(b) An ~~Director may be removed with or without cause at any time by whomever had the right to appoint such Director (for *ex officio* Directors), or for the elected~~ Independent Director~~s,~~ may be removed by an affirmative vote of sixty percent (60%) of the Members. In addition, the Board may remove any voting Director for cause, upon at least seventy-five percent (75%) affirmative votes of the eligible, remaining voting Directors, not counting any Director whose removal is under consideration. ~~The right to elect Directors may not be assigned, sold, pledged or transferred in any manner.~~

Section 6. Committees of the Board. The Board shall by resolution create and appoint all committees of the Board as the Board deems necessary to perform its responsibilities. All committees of the Board shall have such duties as are prescribed and delegated by the Board. Committees to which any of the authority of the Board to manage the Corporation is delegated must have at least two Directors, and a majority of the members of the committee must be Directors.

ARTICLE V.
MEETINGS OF MEMBERS OF THE CORPORATION

Section 1. Annual and Other Meetings of Members.

(a) An annual meeting of the Members to elect Directors, announce election results from electronic elections, and conduct such other business as may come before the meeting, shall be held in December each year, or as soon as practicable thereafter. ~~The failure to hold an annual meeting in accordance with these bylaws shall not affect the validity of a corporate action.~~

(b) Meetings of Members of the Corporation may be called for any purpose or purposes by resolution of the Board, by the chair of the Board, the CEO or the Corporate Secretary, or by a number of Members constituting at least ten ~~(10)~~ percent (10%) of all Members on the roster of Members maintained by the Corporate Secretary~~, which number shall include Members in at least three (3) of the Sectors~~. Meetings of Members shall be held at the principal office of the Corporation or at such other place fixed by the Board as shall be specified in the notice of meeting. Meetings shall be called upon written notice of the time, date, place, and purposes of the meeting given to all Members on the roster of Members maintained by the Corporate Secretary not less than ten (10) nor more than sixty (60) days prior to the date of the meeting. Only Members in good standing with the Corporation, as determined by the Board, have the right to vote at any meeting of the Members. ~~Further, if at any point a Member no longer meets the qualifications for the Sector of which it is a member, the entity may immediately elect to become a member in any Sector for which it does qualify.~~

Section 2. Quorum and Voting Requirements for Meetings of Members.

(a) At any meeting of the Members of the Corporation, attendance in person or by proxy by a majority of the Members in each of at least two-thirds of the Sectors on the roster of Members maintained by the Corporate Secretary shall constitute a quorum.

(b) Except as otherwise expressly provided in the Corporation's Certificate of Formation, these Bylaws, or applicable law, Members shall vote by Sector and each Sector shall have one vote.

(c) To the extent practicable, membership votes will be conducted electronically and prior to annual membership meetings, and will generally be open for a ten (10) day period unless good cause exists to shorten the period.

(d) Except as otherwise expressly provided in the Corporation's Certificate of Formation, these Bylaws or applicable law, actions by the Members of the Corporation shall be approved upon receipt of the affirmative vote of a majority of the Sectors of the Corporation at (1) a meeting at which a quorum is present, in person or by proxy, or (2) an electronic vote which has participation by a quorum. Each Sector's vote shall be determined by the affirmative vote of a majority of the members of the Sector voting at the meeting or in the electronic election.

Section 3. Waivers of Notice of Meetings of Members and Member Meeting Adjournments. Notice of a meeting of Members need not be given to any Member who waives notice~~, either electronically or~~ in writing, ~~in person or by proxy,~~ whether before, during, or after the meeting. The attendance of any Member at a meeting, in person or by proxy, without protesting prior to the conclusion of the meeting the lack of proper notice of such meeting, shall constitute a waiver of notice of the meeting by such Member. When any meeting of Members is adjourned to another time or place, it shall not be necessary to give notice of the adjourned meeting if the time and place to which the meeting is adjourned are announced at the meeting at which the adjournment is taken, and if at the adjourned meeting only such business is transacted as might have been transacted at the original meeting.

Section 4. Action Without a Meeting of Members. Any action, required or permitted to be taken at a meeting of Members, may be taken without a meeting if the proposed action is posted to all Members (via direct email or email to an email distribution list to which Members may subscribe and by posting on the Corporation website) and consented to in writing by the minimum number of Members that would be required to approve the action at a meeting of the Members at which all Members were present. The voting in such a circumstance shall be performed in writing, including via email or other electronic means. The Members shall receive written notice of the results within ten (10) days of the action vote, and all written responses of the Members shall be filed with the Corporate records. The results of such voting will be posted on the Corporation's website.

Section 5. Meetings of the Members to be Open. Notice to the public of the dates, places, and times of meetings of the Members, and all non-confidential material provided to the Members, shall be posted on the Corporation's website at approximately the same time that notice is given to the Members. Meetings of the Members shall be open to the public, subject to reasonable limitations due to the availability and size of meeting facilities; provided, that the meeting may be held in or adjourned to closed session to discuss matters of a confidential nature, including but not limited to compliance and enforcement matters, personnel matters, litigation, or commercially sensitive or critical infrastructure information of the Corporation or any other entity. ~~The results of any action taken without a meeting, as described above, will be posted on the Corporation's website.~~

ARTICLE VI.
MEETINGS OF THE BOARD OF DIRECTORS

Section 1. Regular Meetings of the Board. Regular meetings of the Board shall be held at least quarterly. By resolution adopted at any meeting of the Board, the Board may provide for additional regular meetings that may be held as needed.

Section 2. Special Meetings of the Board. Special meetings of the Board for any purpose or purposes may be called at any time by the chair or by any two Directors. Such meetings may be held upon notice given to all Directors not less than three (3) days prior to the date of the meeting. Such notice shall specify the time, date, place, and purpose or purposes of the meeting and may be given by telephone, email, or other electronic media, or by express delivery.

Section 3. Quorum and Voting Requirements for Meetings of the Board. Unless otherwise expressly provided in the Corporation's Certificate of Formation, these Bylaws or applicable law, (i) the quorum necessary for the transaction of business at meetings of the Board shall be a majority of the voting Directors in person (including by means of any communications system by which all persons participating in the meeting are able to hear each other), or by proxy and of which at least three must be Independent Directors, and (ii) actions by the Board shall be deemed approved upon receipt of the affirmative vote of a majority of the Directors present and voting in person (including by means of any communications system by which all persons participating in the meeting are able to hear each other) or by proxy at a meeting at which a quorum is present but in no case less than four votes.

Section 4. Meetings of the Board to be Open. Notice to the public of the dates, places, and times of meetings of the Board, and all non-confidential material provided to the Board, shall be posted on the Corporation's website at approximately the same time that notice or such material is given to the Directors and at least five (5) business days prior to the scheduled meeting. Meetings of the Board shall be open to the public, subject to reasonable limitations due to the availability and size of meeting facilities; provided, that the Board may meet in or adjourn to closed session to discuss matters of a confidential nature, including but not limited to compliance and enforcement matters, personnel matters, litigation, or commercially sensitive or critical infrastructure information of the Corporation or any other entity. Any or all of the Directors or members of a Board committee, may participate in a meeting of the Board, or a meeting of a committee, in person or by proxy, by means of any communications system by which all persons participating in the meeting are able to hear each other.

Section 5. Waivers of Notice of Board Meetings and Board Meeting Adjournments. Notice of a board meeting of the Board need not be given to any Director who signs, or sends an email confirming a waiver of notice, in person or by proxywriting, whether before, during, or after the meeting. The attendance of any Director at a meeting, in person or by proxy, or who attends the meeting without protesting the lack of notice of such meeting prior to the conclusion of the meeting the lack of proper notice of such meeting, shall constitute a waiver of notice of the meeting by such Director. When a meeting of the Board is adjourned to another time or place, it shall not be necessary to give notice of the adjourned meeting Notice of an adjourned board meeting need not be given if the time and place to which the meeting is adjourned are announced at the meeting at which the adjournment is taken and if at the adjourned meeting, only such business is transacted as might have been transacted at the original meeting and if the period of adjournment does not exceed ten (10) days.

Section 6. Action Without a Meeting. Any action required or permitted to be taken at a meeting of the Board, or of any committee thereof, may be taken by the Board or by the committee without a meeting if the action is consented to in writing by the number of Directors or members of the committee, as the case may be, entitled to vote on the action that would be required to approve the action at a meeting of the Board or committee with all members of the Board or committee present. The call for action without a meeting of the Board may be initiated by the chair or by any two voting Directors. Notice of the proposed call for action without a meeting, and all non-confidential material provided to the Board in connection with the call for

action without a meeting, shall be posted on the Corporation's website and shall be sent via email to an email distribution list to which Members and the public may subscribe at approximately the same time notice of the call for action without a meeting or such material is provided to the Board. The call for action without a meeting of a committee of the Board may be initiated by the chair of the committee or by any two members of the committee. The Directors or members of the committee shall receive written notice of the results of such action within seven (7) days of the action vote. All written responses of the Directors shall be filed with the minutes of the Corporation, and all written responses of members of a committee shall be filed with the minutes of such committee.

Section 7. Emergency Meetings. The Board may meet on urgent matters with not less than two (2) hours' public notice, as necessary or appropriate for emergency conditions threatening health or safety or a reasonably unforeseen situation.

ARTICLE VII.
OFFICERS

Section 1. Selection of Officers. The Board shall elect a CEO and shall ratify the selection of the officers of the Corporation (collectively, the "Officers"). The Management Director shall not participate in votes electing or ratifying Officers. The Corporation shall maintain a list of current Officers ratified by the Board. The duties and authority of the Officers shall be determined from time to time by the Board. Subject to any such determination, the Officers shall have the following duties and authority:

Section 2. Chief Executive Officer ("CEO"). The CEO shall be the chief executive officer of the Corporation. He or she shall be responsible for the day-to-day ongoing activities of the Corporation and shall have such other duties as may be delegated or assigned to him or her by the chair. The CEO may enter into and execute in the name of the Corporation contracts or other instruments not in the regular course of business that are authorized, either generally or specifically, by the Board.

Section 3. Corporate Secretary. The Secretary shall maintain the roster of Members of the Corporation, shall cause notices of all meetings to be served as prescribed in these Bylaws, shall keep or cause to be kept the minutes of all meetings of the Members and the Board, and shall have charge of the seal of the Corporation. The Secretary shall perform such other duties and possess such other powers as are incident to his or her office or as shall be assigned to him or her by the CEO. The CEO may select an Assistant Corporate Secretary at his or her discretion. The Assistant Corporate Secretary is not an Officer of the Corporation.

Section 4. Chief Financial Officer. A Chief Financial Officer shall have custody of the funds and securities of the Corporation, shall keep or cause to be kept regular books of account for the Corporation and shall have the duties normally assigned to a treasurer of a corporation. The Chief Financial officer shall perform such other duties and possess such other powers as are incident to his or her office or as shall be assigned to him or her by the CEO.

Section 5. Other Officers. The CEO may select such other Officers as he or she deems appropriate, subject to ratification by the Board. Any such Officer shall perform such other duties and possess such powers as are incident to his or her office or as shall be assigned to him or her by the CEO.

ARTICLE VIII.
MEMBER REPRESENTATIVES COMMITTEE

Section 1. Purpose of Member Representatives Committee. The Corporation shall have a "Member Representatives Committee" that shall provide advice and recommendations to the Board with respect to: annual budgets, business plans and funding mechanisms of the Corporation; the development of Regional Reliability Standards and Regional Variances in accordance with Texas RE's process; other matters relevant to reliability of the ERCOT Bulk Power System; and other matters pertinent to the purpose and operations of the Corporation. The Member Representatives Committee shall provide its advice and recommendation to the Board through its chair and the vice chair, who also serve as the Affiliated Directors on the Board. The Member Representatives Committee may create subcommittees, task forces, or working groups ("subcommittees") as it deems appropriate to study or discuss selected technical or compliance matters, provide a forum for the review and discussion of current and proposed Reliability Standards, and to make recommendations to the Board as requested or required by the Board or as deemed appropriate to its purpose by the Member Representatives Committee. Because it is elected by the Members of the Corporation and not appointed by the Board, the Member Representatives Committee shall not be a standing committee of the Board of Directors of the Corporation, but is authorized to provide advice and recommendations directly to the Board, through its elected chair and vice chair.

Section 2. Composition of the Member Representatives Committee. The Member Representatives Committee shall consist of two representatives from each Sector to serve two-year terms and will select a chair and vice chair for the Member Representatives Committee to serve two-year terms. The representatives of each Sector shall be officers, employees, or directors of Members in that Sector (or the Member's parent, subsidiary, or other Affiliate); provided however, except for a Sector that has only one Member, only one officer, employee, or director of a Member in a Sector (or the Member's parent, subsidiary, or other Affiliate) may be a representative from that Sector. The Board may by resolution create additional non-voting positions on the Member Representatives Committee on its own initiative or at the written request of any group of Members of the Corporation that believes its interests are not adequately represented on the Member Representatives Committee. There shall be no limit on the number of terms that an officer, employee, or director of a Member (or the Member's parent, subsidiary, or other Affiliate), may serve on the Member Representatives Committee.

Section 3. Election of Representatives of the Member Representatives Committee. Unless a Sector adopts an alternative election procedure, the election of representatives from each Sector to the Member Representatives Committee, and any election to fill a vacancy, shall be conducted in accordance with the following process, which shall be administered by the Secretary of the Corporation: ~~.~~

(a) During the period beginning no more than ninety (90) days and ending no less than fifteen (15) days prior to an annual meeting, or beginning no more than forty-five (45) days and ending no less than fifteen (15) days prior to a special election to fill a vacancy on the Member Representatives Committee, nominations may be submitted for candidates for election to the Member Representatives Committee. A nominee for election as a Sector representative must be an officer, employee, or director of a Member in that Sector (or the Member's parent, subsidiary, or other Affiliate). No more than one nominee who is an officer, employee, or director of a Member (or the Member's parent, subsidiary, or other Affiliate) may stand for election in any single Sector; if more than one officer, employee, or director of a Member (or the Member's parent, subsidiary, or other Affiliate) is nominated for election from a Sector, the Member shall designate

which such nominee shall stand for election. The election of representatives shall be conducted over a period of ten (10) days using an electronic process approved by the Corporate Secretary.

(b) Each Member in a Sector shall have one vote for each Representative to be elected from the Sector in that election and may cast no more than one vote for any nominee. The nominee receiving the highest number of votes in each Sector shall be elected to one Representative position to be filled from that Sector and the nominee receiving the second highest number of votes shall be elected as the second Representative position for that Sector. To be elected on the first ballot, a nominee must receive a number of votes equal to a simple majority of the Members in the Sector casting votes in the election. If no nominee in a Sector receives a simple majority of votes cast in the first ballot, a second ballot shall be conducted which shall be limited to the number of candidates receiving the three (3) highest vote totals on the first ballot. The nominees receiving the two highest totals of votes on the second ballot shall be elected to the Representative positions for the Sector.

(c) A Sector may adopt an alternative procedure to the foregoing to nominate and elect its Representatives to the Member Representatives Committee if the alternative procedure is approved by vote of at least two-thirds of the Members in the Sector, provided, however that any alternative procedure ~~may~~ must be reviewed and ~~dis~~approved by the Board.

(d) A Sector may elect an Alternate to serve in place and at the convenience of the Sector's Member Representatives Committee Representative(s) in the event a Member Representatives Committee Representative cannot attend a Member Representatives Committee meeting.

Section 4. Chair and Vice Chair of the Member Representatives Committee. After the selection of its Representatives, the Member Representatives Committee shall select a chair and vice chair from among its voting Representatives by majority vote to serve during the upcoming two-year term and be the Affiliated Directors on the Board. The selected chair and vice chair may not be representatives of the same Sector and may not concurrently serve on the Board of ERCOT ISO. The Board shall be notified of the selection of the chair and vice chair, but the selection will not be subject to approval of the Board. The chair is responsible for ensuring that minutes of the meetings are properly maintained and made available to the public, but the chair may delegate this responsibility to the vice chair or to another Representative of the Member Representatives Committee who may be designated as secretary of the Member Representatives Committee.

Section 5. Vacancies on the Member Representatives Committee. In the event that any Representative of the Member Representatives Committee ceases to serve as a Representative of the Member Representatives Committee as a result of his or her death, resignation, retirement, disqualification, removal, or other cause, the Members in the Sector of which such Representative was a representative shall elect, as soon thereafter as reasonably practicable, and in accordance with the procedures in this Article VIII, a new Representative to replace the Representative of the Member Representatives Committee who ceased to serve. For those Sectors that have elected an Alternate, the Alternate will fill a vacancy left by the Sector's Member Representative until a new Sector Member Representative is elected by the Sector.

Section 6. Meetings of the Member Representatives Committee. The Member Representatives Committee will plan and hold quarterly meetings, at a time and place determined by the Member Representatives Committee, normally shortly before the regular meetings of the Board, and posted on the Corporation's website. Except for closed session meetings specifically allowed by this Section, all meetings shall be open to the public. ~~The~~

~~Member Representatives Committee shall adopt such procedural rules as are needed to operate in accordance with its purpose and will include procedures for coordinating with employees of the Corporation who provide administrative support, as set forth in subsection 6(c), below.~~

(a) Notice to the public of the dates, places, and times of meetings of the Member Representatives Committee and any subcommittees, and all non-confidential material provided to the Representatives on the Member Representatives Committee or any subcommittees, shall be posted on the Corporation's website at approximately the same time that notice or such material is given to the Member Representatives Committee, which will normally be at least five (5) business days prior to the scheduled meeting. Meetings of the Member Representatives Committee and subcommittees shall be open to the public, subject to reasonable limitations due to the availability and size of meeting facilities; provided, that the Member Representatives Committee and subcommittees may meet in or adjourn to closed session to discuss matters of a confidential nature, including but not limited to confidential planning information, critical infrastructure information, or commercially sensitive information of the Corporation or any other entity. Participation in a meeting of the Member Representatives Committee or subcommittee may be accomplished through use of a communications system by which all persons participating in the meeting are able to hear each other.

(b) Special meetings may be called for any purpose or purposes by the chair of the Member Representatives Committee or by any three (3) Representatives of the Member Representatives Committee, which number shall include representatives from at least three Sectors, and require notice given to all Representatives of the Member Representatives Committee not less than seven (7) days prior to the date of the meeting. Such notice shall specify the time, date, place, and purpose or purposes of the meeting and may be given by telephone, ~~facsimile~~email, or other electronic media, or by express delivery.

(c) The Member Representatives Committee shall effectively coordinate with the employees of the Corporation and adopt procedural rules for the voting for Representatives, scheduling of meetings, and public posting of required meeting information and minutes. The chair or vice chair of the Member Representatives Committee shall provide all meeting agendas, material, minutes and other information required or desired to be posted on the Corporation's website to appropriate Corporation employees at least one (1) business day prior to the time such information should be posted.

Section 7. Action Without a Meeting of Members. Any action, required or permitted to be taken at a meeting of the Member Representatives Committee, may be taken without a meeting if the proposed action is posted to all Committee Members via direct email and consented to in writing by a majority of the Representatives. The voting in such a circumstance shall be performed in writing, including via email or other electronic means. The Representatives shall receive written notice of the results within ten (10) days of the action vote, and all written responses of the Representatives shall be retained as a corporate record. The results of such voting will be reported at the next in-person Member Representatives Committee meeting.

Section 8. Waivers of Notice of Meetings of the Member Representatives Committee and Meeting Adjournments. Notice of a meeting of the Member Representatives Committee need not be given to any member of the Member Representatives Committee who waives notice ~~electronically or otherwise in writing~~, in ~~person or by proxy~~writing, ~~whether~~ before, during, or after the meeting. The attendance of any Committee member at a meeting, in person or by proxy, ~~or who attends the meeting~~ without protesting prior to the conclusion of the meeting the lack of proper notice of such meeting, shall constitute waiver of notice of the meeting ~~of the meeting~~ by such Committee Member ~~the lack of notice of such meeting~~. ~~Notice of an~~

~~adjourned~~When a meeting of the Member Representatives Committee is adjourned to another time or place, it shall not be necessary to ~~need not be~~ give~~n if~~ notice of the adjourned meeting if the time and place to which the meeting is adjourned are announced at the meeting at which the adjournment is taken, and if at the adjourned meeting only such business is transacted as might have transacted at the original meeting ~~and if the period of adjournment does not exceed ten (10) days~~.

Section 9. Quorums and Voting for Meetings of the Member Representatives Committee. The quorum necessary for the transaction of business at meetings of the Member Representatives Committee shall be the presence, in person or by proxy, of two-thirds of the voting Representatives on the Member Representatives Committee entitled to attend. Each voting member of the Member Representatives Committee shall have one (1) vote on any matter coming before the Member Representatives Committee that requires a vote. Except as otherwise expressly provided in the Corporation's Certificate of Formation, these Bylaws or applicable law, actions by members of the Member Representatives Committee shall be approved upon receipt of the affirmative vote of a majority of the voting members of the Member Representatives Committee present (by means of any communications system by which all persons participating in the meeting are able to hear each other) and voting at any meeting at which a quorum is present.

Section 10. Alternates and Proxies. Member Representatives may designate another Member Representative or an employee of the Member Representative's organization (or the Member's parent, subsidiary, or other Affiliate) as a proxy if both the Member Representative and the Sector Alternate are unable to attend a Member Representatives Committee meeting. A member of the Member Representatives Committee may give a proxy only to a person who is an officer, employee, or director of a Member, registered in the same Sector (or the Member's parent, subsidiary, or other Affiliate).

Section 11. Other Procedures of the Member Representatives Committee. Except as to any matter as to which the procedure to be followed by the Member Representatives Committee is expressly set forth in these Bylaws, the Member Representatives Committee may adopt such additional procedures, not inconsistent with these Bylaws, as it deems appropriate, subject to review and ~~dis~~approval by the Board.

ARTICLE IX.
OTHER COMMITTEES AND SUBCOMMITTEES

Section 1. Other Committees and Subcommittees of the Corporation. ~~In addition to those committees specified by these Bylaws, to which the Board shall appoint members in accordance with the requirements of these Bylaws, t~~The Board may by resolution create ~~standing~~ committees and subcommittees of the Corporation to provide advice to the Board.~~; and may in addition by resolution~~ The Board will appoint the members of such committees, subcommittees, and task forces ~~and Sector-specific forums as the Board deems necessary or desirable to carry out the purposes of the Corporation. The Board shall appoint members to such standing committees and other committees of the Corporation~~ that are representative of Members, and other interested parties, ~~and the public,~~ as appropriate, that provide for balanced decision-making and that include persons with sufficient technical knowledge and experience. All committees and~~,~~ subcommittees~~, task forces and Sector-specific forums~~ shall have such scope and duties~~, not inconsistent with law, as are specified in these Bylaws and the Rules of Procedure of the Corporation or otherwise~~ as determined by the Board.

ARTICLE X.
BUDGETS AND FUNDING

Section 1. Compensation of the Board and Member Representatives Committee.

(a) The Board shall have a Director compensation committee (the "Director Compensation Committee") to have the right to evaluate and fix from time to time, by simple majority vote, the amount of the annual retainer fee or other compensation to be paid to the Independent Directors for their services to the Corporation, including any fees to be paid for each meeting of the Board or any Board committee attended by an Independent Director. The Director Compensation Committee will evaluate the fee or other compensation annually to ensure that Director compensation is appropriate. The Director Compensation Committee shall consist of two (2) Independent Directors that are not currently serving as Board Chair and Vice Chair (unless there is an Independent Director vacancy, in which case the Board Vice Chair will serve on the Committee until the vacancy is filled), two (2) Affiliated Directors, and the CEO. The Board Chair shall appoint an Independent Director as the Chair of the Director Compensation Committee. Meetings of the Director Compensation Committee are not required to be publicly posted.

(b) No compensation shall be paid to any Management Director, Affiliated Director, or *ex officio* Director for his or her services on the Board, other than the compensation paid to the Management Director for services as CEO of the Corporation. No compensation shall be paid by the Corporation to any member of the Member Representatives Committee for his or her services on the Member Representatives Committee.

(c) Independent Directors shall be entitled to be reimbursed their reasonable out-of-pocket expenditures for attending meetings and conducting the business of the Corporation.

Section 2. Preparation and Adoption of Annual Budget, Business Plan, and Funding Mechanism. The Board shall require the CEO to prepare for Board approval an annual business plan and budget for the administrative and other expenses of the Corporation, including the expenditures for the fiscal year for any material special projects undertaken by the Corporation and reasonable and proper reserves and provisions for contingencies, in accordance with all NERC and FERC requirements. The annual business plan, budget and funding mechanism of the Corporation shall be for a fiscal year commencing on January 1 and ending on December 31. Each annual business plan, budget, and funding mechanism shall be approved by the Board at a regular meeting or a special meeting of the Board duly called for that purpose. The Board shall approve each annual business plan, budget, and funding mechanism at a time that allows for timely submittal of the approved annual business plan, budget, and funding mechanism to the applicable regulatory authorities.

Section 3. Comments During Preparation of Annual Business Plan and Budget. In preparing the annual business plan and budget, the Board shall require that the CEO post a draft business plan and budget for review and comment by the Members of the Corporation, the Member Representatives Committee, and the standing committees of the Corporation for at least five (5) business days prior to the date of the meeting of the Board at which the annual business plan and budget is to be adopted.

Section 4. Modified or Supplemental Budgets. During the course of a fiscal year, the Board may modify any approved budget or develop and approve a supplemental budget if determined by the Board to be necessary due to such factors as a shortfall in revenues of the

Corporation from projected levels, incurred or anticipated expenditures, duties, or new projects not provided for in the annual budget, or such other factors as in the judgment of the Board warrant modification of the budget for the fiscal year or development of a supplemental budget. In preparing a modified or supplemental budget, the Board shall follow the provisions of this Article X, Section 4 to the extent practicable in the judgment of the Board in light of the urgency of the circumstances necessitating preparation and approval of the modified or supplemental budget. Each modified or supplemental budget shall be approved by the Board at a regular meeting or a special meeting of the Board duly called for that purpose.

Section 5. Submission of Annual Business Plans and Budgets to the Regulatory Authorities. Each annual budget, annual business plan, and annual, modified, or supplemental budget approved by the Board shall be submitted by the Corporation to the ERO and any applicable regulatory authorities for approval in accordance with its regulations, and shall not be effective until approved by the applicable regulatory authorities. If ordered to modify or remand an annual budget, business plan, or annual, modified, or supplemental funding mechanism, the Board shall promptly following such order adopt such modifications to the business plan, budget, or funding mechanism as are required or directed by the order of the ERO and any applicable regulatory authority.

ARTICLE XI.
AMENDMENTS TO THE BYLAWS

Section 1. Amendments to the Bylaws. These Bylaws may be altered, amended, or repealed by action of the Membership, as set forth below. Any alteration, amendment, repeal or adoption of Bylaws shall be subject to any applicable requirements for filing with or approval by the ERO or any other applicable regulatory authority. These Bylaws may be altered, amended, or repealed as follows:

(a) ~~Any Director or Member s~~Suggested~~ing~~ amendments to these Bylaws ~~must~~ may be made through the submission~~t a~~of the proposed~~al of the~~ amendments, including any necessary supporting documents, to the ~~CEO~~Corporate Secretary.

(b) The ~~CEO~~ Corporate Secretary shall place the proposal on the agenda for a Board meeting, or if the Board has designated a standing committee with authority to review proposed amendments and make a recommendation to the Board, the Corporate Secretary shall place the proposal on that committee's next scheduled meeting agenda. ~~in the time and manner prescribed by the Board and within ninety-five (95) days of the request.~~

(c) If the proposal is approved by an act of the Board as set forth in Article VI, Section 3, the Board shall place the proposal on the agenda of the next Annual Meeting of the Corporate Members unless the Board in its discretion calls a Special Meeting of the Corporate Members to vote on the proposal or determines to seek Membership approval without a meeting as provided in Article V, Section 4.

(d) If the proposal is not approved by the Board, the Members of the Corporation may call a meeting, pursuant to Article V, Section 1(b), for the purpose of voting on a proposal not approved by the Board. Any such proposal must be approved by a vote of five of the six Sectors at a meeting of Members called for that purpose or by written consent of five of the Sectors, where the number of votes for and against the proposed alteration, amendment, repeal or adoption of Bylaws shall be determined in accordance with Article V, Section 2.

ARTICLE XII.
INDEMNIFICATION; PROCEDURE; DISSOLUTION

Section 1. Indemnification. The Corporation shall indemnify each person who at any time shall serve, or shall have served, as an officer, Director, employee, or other corporate agent of the Corporation, is or was serving at its request as a director, officer, partner, venturer, proprietor, employee, agent or similar functionary of another foreign or domestic corporation, partnership, joint venture, sole proprietorship, trust, employee benefit plan or other enterprise ("Indemnified Parties"), to the full extent from time to time permitted by the Texas Business Organizations Code and other applicable law. Such right of indemnification shall inure to the benefit of the legal representative of any such Indemnified Party. The foregoing indemnification shall be in addition to, and not in restriction or limitation of, any privilege or power that the Corporation may have with respect to the indemnification or reimbursement of its Indemnified Parties. The Corporation shall also pay or advance reasonable expenses incurred by an Indemnified Party in connection with a proceeding in advance of the final disposition of the proceeding upon receipt of a written affirmation by the Indemnified Party of a good faith belief that the standard of conduct necessary for indemnification under this Article XII and the Texas Business Organizations Code has been met and a written undertaking by or on behalf of the officer, Director, or other corporate agent to repay the amount if it shall be ultimately determined that the Indemnified Party was not entitled to be indemnified by the Corporation.

Section 2. Parliamentary Rules. In the absence of and to the extent not inconsistent with specific provisions in these Bylaws, meetings or other actions pursuant to these Bylaws shall be governed by procedures that the Board may, from time to time, establish by resolution.

Section 3. Dissolution. Upon dissolution of the Corporation, in accordance with the Certificate of Formation, the remaining assets of the Corporation after payment of debts shall be distributed in the manner determined by the Board, provided that, (i) no part of the assets shall be distributed to any Director of the Corporation, and (ii) the distribution of assets shall be consistent with the requirements of Section 501(c)(3) of the United States Internal Revenue Code of ~~1954~~1986, as amended.

ARTICLE XIII.
CONFLICTS OF INTEREST

Section 1. Conflicts of Interest.

(a) Each Director shall have an affirmative duty to disclose to the Board or committee (as the case may be) any actual or potential conflicts of interest of the Director that arise during his or her tenure as a Director where, and to the extent that, such conflicts or potential conflicts directly or indirectly affect any matter that comes before the Board. A Director with a direct or potentially conflicting interest in a matter shall recuse himself from deliberations and actions on the matter in which the conflict arises and shall abstain on any vote on the matter and not otherwise participate in a decision on the matter. Any disclosure of a potential conflict of interest by a Director shall be noted in the minutes of the Board meeting at which the direct interest is disclosed. Mere attendance at the meeting, without participating in discussion of the issue raising the potential conflict, shall not constitute participation.

(b) The Corporation may not make any loan to a Director, committee member or officer of the Corporation. A Member, Director, officer, or committee member of the Corporation may not lend money to, or otherwise transact business with, the Corporation except as otherwise

provided by these Bylaws, the Certificate of Formation, and applicable law. A related party transacting business with the Corporation has the same rights and obligations relating to those matters as other persons transacting business with the Corporation, provided the related party nature of the transaction is known to the Board. The Corporation may not borrow money from, or otherwise transact business with, a Member, Director, officer, or committee member of the Corporation unless the transaction is described fully in a legally binding instrument, is in the Corporation's best interests, and is on terms no less favorable to the Corporation than could be obtained in an arms-length transaction. The Corporation may not borrow money from, or otherwise transact business with, a Member, Director, officer, or committee member of the Corporation without full disclosure of all relevant facts and without the Board's approval, not including the vote of any person having a personal interest in the transaction.

Section 2. Prohibited Acts. No Member, Director, officer, or committee member of the Corporation may do any of the below-listed prohibited acts. Engaging in these prohibited acts may lead to sanction, suspension, expulsion or termination after a hearing as described in these Bylaws. The prohibited acts include the following:

(a) Do any act in violation of these Bylaws.

(b) Do any act in violation of a binding obligation of the Corporation except with the Board's prior approval.

(c) Do any act with the intention of harming the Corporation or any of its operations.

(d) Receive an improper personal benefit from the operation of the Corporation.

(e) Use the Corporation's assets, directly or indirectly, for any purpose other than carrying on the Corporation's business.

(f) Wrongfully transfer or dispose of Corporation property, including intangible property such as goodwill.

(g) Use the Corporation's name (or any substantially similar name) or any trademark or trade name adopted by the Corporation, except on behalf of Corporation in the ordinary course of its business or as a reference to the Corporation or its region.

(h) Disclose any of Corporation's or Members' business practices, trade secrets, or any other confidential or proprietary information not generally known to the business community to any person not authorized to receive it.

Section 3. Loans and Guarantees. Neither participation in the activities of the Corporation nor any provision of these Bylaws or of the Certificate of Formation shall be deemed to constitute a pledge or loan of the credit of any Member for the benefit of the Corporation or a guarantee by any Member of any obligation of the Corporation.

ARTICLE XIV.
BOOKS AND RECORDS; AUDIT; FISCAL YEAR

Section 1. Access to Books and Records. All Members of the Corporation will have access to the books and records of the Corporation, including financial statements and budgets; however, the Board shall establish procedures by which a Member, upon written demand stating the purpose of the demand may examine and copy the books and records of the Corporation. If necessary to protect the confidential information of the Corporation, a Member requesting examination of any of the Corporation's non-public books and records will be required to sign a confidentiality and non-disclosure agreement before viewing such information. The procedures shall include policies that provide reasonable protection against the unnecessary disclosure of information related to individual employees, including their compensation.

Section 2. Audit. At least annually, an audit of the financial statements of the Corporation shall be performed by the Auditor approved by the Board. The Auditor's opinion and the audited financial statements will be made available to all Members as described in Article XIV, Section 1.

Section 3. Fiscal Year. The fiscal year of the Corporation shall be from January 1 through the following December 31, unless otherwise established by resolution of the Board.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. XXXX**

JOINT PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION, FLORIDA RELIABILITY COORDINATING COUNCIL, INC., AND SERC RELIABILITY CORPORATION FOR APPROVALS IN CONNECTION WITH THE DISSOLUTION OF THE FLORIDA RELIABILITY COORDINATING COUNCIL, INC. REGIONAL ENTITY

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February 27, 2019

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ATTACHMENTS

Attachment 1	Termination Agreement for the Amended and Restated Delegation Agreement between the North American Electric Reliability Corporation and Florida Reliability Coordinating Council
Attachment 2	CLEAN – Revised Exhibit A to Regional Delegation Agreement with SERC Reliability Corporation
Attachment 3	REDLINE – Revised Exhibit A to Regional Delegation Agreement with SERC Reliability Corporation
Attachment 4	Transfer of Delegated Authority over Florida Reliability Coordinating Council RE Registered Entities to SERC Reliability Corporation
Attachment 5	CLEAN – Amended SERC Bylaws
Attachment 6	REDLINE – Amended SERC Bylaws

UNITED STATES OF AMERICA
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North American Electric Reliability Corporation	**)** **)**	**Docket No. XXXX**

JOINT PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION, FLORIDA RELIABILITY COORDINATING COUNCIL, INC., AND SERC RELIABILITY CORPORATION FOR APPROVALS IN CONNECTION WITH THE DISSOLUTION OF THE FLORIDA RELIABILITY COORDINATING COUNCIL, INC. REGIONAL ENTITY

I. INTRODUCTION

Following the mutual decision reached by the North American Electric Reliability Corporation ("NERC")[1] and Florida Reliability Coordinating Council ("FRCC") to terminate the Delegated Authority[2] of the FRCC Regional Entity ("FRCC RE") division of FRCC, NERC, as the Electric Reliability Organization ("ERO"), FRCC, and SERC Reliability Corporation ("SERC") as the Regional Entity assuming FRCC RE's Delegated Authority over the registered entities in FRCC RE's footprint (therefore known as the "Transferee Regional Entity") (collectively, the "Petitioners"), request that the Federal Energy Regulatory Commission ("FERC" or the "Commission") approve the following, in accordance with Section 215(e)(4) of the Federal Power Act[3] and Sections 39.8 and 39.10[4] of the Code of Federal Regulations:

(1) termination of the Amended and Restated Delegation Agreement ("RDA") between NERC and FRCC pursuant to the terms of a Termination Agreement (**Attachment 1**);

(2) the transfer of all registered entities in the FRCC RE footprint to SERC by July 1, 2019;

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[1] 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").
[2] This term is defined in the RDA between NERC and FRCC to include the authority to propose and enforce Reliability Standards and to undertake related activities set forth in the RDA.
[3] 16 U.S.C. § 824o (2012).
[4] 18 C.F.R. §§ 39.8 and 39.10 (2018).

(3) amendments to Exhibit A[5] to the RDA between NERC and SERC (**Attachments 2 and Attachment 3**) to illustrate the changed geographic footprint of SERC resulting from the transfer of registered entities from FRCC RE to SERC;

(4) amendments to the SERC Bylaws (**Attachments 5 and Attachment 6**);

(5) a Special Assessment for FRCC RE to assist with wind down costs;

(6) the allocation of FRCC RE penalty monies[6] towards wind down costs of FRCC RE;

(7) the allocation of SERC penalty monies towards costs associated with SERC's assumed Delegated Authority over the transferring registered entities from the FRCC RE footprint;

(8) the use of FERC-approved 2019 assessment monies to fund costs associated with the wind down of FRCC RE operations and SERC's Delegated Authority over the transferring registered entities from the FRCC RE footprint.

Together, these requests were approved by the NERC Board of Trustees on February 7, 2019, and are referred to herein as the "Proposed Transaction." The Petitioners reserve their right to withdraw from the Proposed Transaction if the Commission does not approve any of the material terms of the Proposed Transaction as outlined herein.

II. REQUEST FOR EXPEDITED COMMISSION ACTION AND SHORTENED COMMENT PERIOD

The Petitioners respectfully request that the Commission consider this Petition on an expedited basis, to allow the issuance of an order in this proceeding by May 1, 2019. The Petitioners also request a shortened comment period of no more than 14 days.

The requested timeline will permit orderly transition of registered entities from FRCC RE to SERC and seamless mid-year seating of former FRCC representatives on the SERC Board Executive Committee ("BEC") and SERC Board. The Commission's order in this proceeding will provide the certainty that is needed for the Petitioners to complete transition activities. To minimize

[5] No other portion of the NERC-SERC RDA is being amended.

[6] Defined as penalties associated with noncompliance with Reliability Standards by FRCC RE entities that were part of the FRCC RE caseload prior to the date in which entities are transferred to SERC. The definition does not include any noncompliance by FRCC in its capacity as a Reliability Coordinator.

disruption to registered entities in FRCC RE, the Petitioners have engaged in preliminary activities for the transfer of files, documents and other information necessary for SERC's assumption of Delegated Authority over FRCC RE's registered entities by July 1, 2019. Expeditious processing will also allow for additional training and outreach to registered entities. The date that the Commission approves the filing will serve as the date upon which the terms of the proposed Termination Agreement become effective ("Effective Date"). An expedited order will enable FRCC to complete its wind down activities and cease to be a Regional Entity on August 31, 2019 (the "Termination Effective Date").

A shortened comment period is warranted due to extensive coordination with affected registered entities prior to the FRCC Board's decision to dissolve the FRCC RE division. Over the past twelve months, the Petitioners have sought the input of impacted registered entities. For example, since late 2017, FRCC's stakeholder board has been examining the issues that led to its decision to seek dissolution of the RE division. In addition, the FRCC Board formed a stakeholder taskforce which met more than 15 times to examine potential impacts of a transition to SERC. This coordination mitigates the need for a longer comment period.

III. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:[7]

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Holly A. Hawkins*
General Counsel

Nina H. Jenkins-Johnston*
Senior Counsel
Candice Castaneda*
Counsel
North American Electric Reliability Corporation
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[7] *Persons to be included in Commission's official service list. The Petitioners respectfully request 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.

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IV. TERMINATION OF FRCC RE'S DELEGATED AUTHORITY

FRCC's governance structure includes a NERC Regional Entity division and a Member Services division. On October 30, 2018, after a careful, deliberate review of FRCC's governance structure, FRCC announced its decision to dissolve the FRCC RE division. As part of its review, FRCC examined factors including, but not limited to, maintaining the reliability of the bulk power system ("BPS") in Florida, customer costs, and the extent to which stakeholders would be able to participate in governance of a successor Regional Entity. FRCC undertook its review in response to NERC's determination that NERC Regional Entities should be separate corporate entities from NERC registered entities.

The NERC-FRCC RDA expires on December 31, 2020; however, it permits early termination upon a date that is mutually agreed to by the parties.[8] NERC and FRCC have agreed that, subject to Commission approval of the Proposed Transaction, as outlined herein, and of the terms of the Termination Agreement (**Attachment 1**), and absent any material deviation from the terms of the Proposed Transaction, the RDA should be terminated and FRCC RE should cease to act as a Regional Entity on the Termination Effective Date.[9] As a result of FRCC's decision to seek the dissolution of the FRCC RE division, the Petitioners are working to ensure that FRCC RE's wind-down and transfer of registered entities and Delegated Authority to SERC are performed in a manner that maintains reliability of the BPS and enhances the efficiency of the

[8] Sections 12(a) and (b) of the RDA.
[9] On October 30, 2018, FRCC's board of directors voted to authorize FRCC's President and Chief Executive Officer to terminate the NERC-FRCC RDA at the appropriate time, so long as all necessary legal and regulatory approvals had been obtained on terms as outlined in this filing and with no material modifications.

ERO Enterprise. Consistent with the RDA,[10] the Termination Agreement sets forth the following NERC and FRCC obligations to support orderly wind-down of FRCC RE's Delegated Authority and transfer of Delegated Authority to SERC.

a. NERC's Obligations in Connection with the Proposed Transaction

The proposed Termination Agreement requires NERC to take the following steps outlined in Section 3 of the Termination Agreement to effectuate the dissolution and wind down of FRCC RE:

(i) identify SERC as the Transferee Regional Entity for all registered entities in the FRCC RE footprint;
(ii) identify the Load-Serving Entities ("LSEs") associated with each FRCC RE registered entity for statutory assessment purposes and specify that those LSEs shall, as of the Termination Effective Date, be included as LSEs within SERC;

(iii) assist in the transition of compliance monitoring and enforcement processes to SERC;

(iv) seek a Special Assessment to assist FRCC RE with wind down costs;

(v) request approval to deviate from any applicable rules and policies and to apply FRCC RE Penalty monies as follows:

a. Penalty monies processed and submitted[11] to NERC between July 1, 2018 and July 1, 2019 to apply towards wind down costs; and

b. Penalty monies processed and submitted between July 1, 2019 and December 31, 2019, or not otherwise applied towards wind-down costs, to be reimbursed to FRCC entities on a pro-rata basis;

(vi) request approval to deviate from any applicable rules and policies to apply SERC penalties towards the increased cost of SERC's assumed Delegated Authority over the transferring FRCC RE registered entities;

(vii) request approval to apply Commission-approved 2018 and 2019 FRCC and SERC assessments towards costs associated with the Proposed Transaction;

(viii) coordinate with FRCC to ensure the disconnection of information technology interfaces between NERC and FRCC and its employees and contractors with associated

[10] Sections 12(c) and (d) of the RDA.
[11] Defined as penalties for FRCC entities billed but not yet collected, penalties for FRCC entities pending FERC approval, and penalties for FRCC entities submitted to NERC and pending NERC Board of Trustees Compliance Committee approval.

Regional Entity responsibilities; and,

(ix) submit applicable agreements, governance materials, and other corporate documents necessary to effectuate the termination of the RDA to the Commission for approval both prior to and after the Termination Effective Date.

As of the date of this Petition, NERC has completed the first two obligations. The NERC Board of Trustees approved SERC as the transferee Regional Entity on February 7, 2019. NERC has also identified the LSEs in the FRCC RE footprint associated with each registered entity being transferred to SERC. In addition, the Petitioners have initiated efforts to transition CMEP activities from FRCC RE to SERC. These activities and this Petition facilitate completion of NERC's remaining obligations pursuant to the Termination Agreement, subject to a Commission order in this proceeding (*see infra* **Section VII** for details regarding the requested Special Assessment).

b. FRCC's Obligations in Connection with the Proposed Transaction

The proposed Termination Agreement imposes several obligations on FRCC to effectuate dissolution of FRCC RE and to support the transfer of Delegated Authority to SERC. In particular, Section 6 of the Termination Agreement states that FRCC must:

(i) transition relevant files and documents pertaining to FRCC RE's Delegated Authority and delegation-related activities to SERC;

(ii) submit to NERC detailed descriptions of the reallocation of any Commission-approved 2018 and/or 2019 assessment funds for the wind-down and dissolution of the FRCC RE and the termination and transfer of the FRCC RE Delegated Authority, including completion of the obligations set forth in the Termination Agreement and other revenue sources for the FRCC RE on April 1, 2019 and May 1, 2019;

(iii) use any Special Assessment authorized by the Commission to pay for wind down costs, including retention agreements for fourteen (14) FRCC RE staff and nine (9) key shared corporate staff upon dissolution of FRCC RE;

(iv) provide NERC the estimated value of FRCC penalties to be applied towards wind down costs by May 1, 2019;

(v) submit to NERC unaudited quarterly financial reports for all 2019 quarters leading up

to and including the Termination Effective Date;[12]

(vi) submit to NERC by April 1, 2020, all audited financial statements of FRCC for 2019;

(vii) submit to NERC by April 1, 2020, a reconciliation of actual expenses with budgeted expenses for 2019; and,

(viii) verify the completion of the steps identified in this section of the Termination Agreement through a certification signed by an officer of FRCC no later than one hundred and fifty (150) days following the Termination Effective Date.

As of the date of this Petition, FRCC has initiated the first obligation. FRCC will complete this obligation and the remaining obligations in this section contingent upon the issuance of an order by the Commission approving the Proposed Transaction consistent with the material terms outlined herein.

V. AUTOMATIC TERMINATION OF THE SERC AND FRCC RE COMPLIANCE MONITORING AND ENFORCEMENT AGREEMENT

In 2010, SERC and FRCC entered into a compliance monitoring and enforcement agreement pursuant to which SERC assumed responsibility as the Compliance Enforcement Authority ("CEA") for FRCC's registered functions within the FRCC RE Region ("SERC-FRCC CMEP Agreement").[13] The SERC-FRCC CMEP Agreement automatically renewed on January 1, 2018. Although the SERC-FRCC CMEP Agreement will become moot on July 1, 2019 if the Commission approves the transfer of all Registered Entities, including FRCC, to SERC, it will automatically terminate at the end of the calendar year that FRCC ceases to be a Regional Entity – December 31, 2019.[14] After dissolution of FRCC RE, FRCC will be registered in SERC along with the remaining entities in the FRCC RE footprint (*see infra* **Section VI** below for discussion

[12] NERC will continue to provide the unaudited quarterly financial reports to the Commission and post them on its web site, along with the unaudited quarterly financial reports of NERC and the other Regional Entities, consistent with longstanding practice.

[13] The Commission approved the SERC-FRCC CMEP Agreement in *Order Conditionally Accepting Compliance Monitoring and Enforcement Program Agreements and Revised Delegation Agreements, and Ordering Compliance Filing*, 132 FERC ¶ 61,024 (2010).

[14] Section 5(b) and (c) of the SERC-FRCC CMEP Agreement

of the transfer of registered entities in FRCC RE to SERC). Therefore, SERC will continue to act as the CEA for FRCC following termination of the RDA and SERC-FRCC CMEP Agreement.

VI. RATIONALE AND PROCESS FOR TRANSFER OF FRCC RE REGISTERED ENTITIES

NERC proposes transferring to SERC all 36 FRCC RE registered entities and expanding SERC's boundaries to incorporate such entities (detailed rationale in **Attachment 4)**. Although the NERC ROP does not contain specific criteria for the transfer of multiple registered entities to one or more Regional Entities upon a Regional Entity dissolution, NERC was informed by the following criteria in Section 1208 of the NERC ROP:

(i) the location of the registered entity's BPS facilities in relation to the geographic and electrical boundaries of SERC;

(ii) the impact of the proposed transfer on other BPS owners, operators, and users, including affected Reliability Coordinators ("RCs"), Balancing Authorities ("BAs"), and Transmission Operators ("TOPs"), as appropriate;

(iii) the impact of the proposed transfer on the current and future staffing, resources, budgets and assessments to other LSEs of SERC;

(iv) the sufficiency of SERC's staffing and resources to perform compliance monitoring and enforcement activities with respect to the registered entities being transferred; and

(v) the registered entities' compliance history with FRCC RE, and the manner in which pending compliance monitoring and enforcement matters concerning the registered entities would be transitioned from FRCC RE to SERC.

NERC also applied the Commission's guidance on transfers of registered entities within the ERO Enterprise. The Commission has noted that a Regional Entity's boundary change "should be carefully considered and should serve to improve the effectiveness or efficiency of the Regional Entities and NERC's administration of reliability, and should not merely benefit an individual registered entity."[15] The Commission also stated that NERC may consider whether a transfer will

[15] *Order Conditionally Approving Revised Pro Forma Delegation Agreement, Revised Delegation Agreements with Regional Entities, Amendments to Rules of Procedure and Certain Regional Entity Bylaws*, 133 FERC ¶ 61,061 (2010) at P 72 ("October 2010 Order"). See also *Order Denying Rehearing*, 134 FERC ¶ 61,179 (2011) at P 15 ("March 2011

improve the registered entity's contribution to BPS reliability.[16] The Commission added that the financial impacts of a transfer are not the determinative factor,[17] and that NERC is responsible for promoting consistent treatment of registered entities between the Regional Entities to "ensure[] that registered entities will have no justification to shop for a favorable Regional Entity …."[18]

NERC's proposed transfer of the FRCC RE registered entities to SERC is consistent with Section 1208 of the ROP as well as Commission precedent. In particular, NERC identified SERC as the appropriate Transferee Regional Entity based on the following: (i) SERC is the only Regional Entity sharing geographic and electrical boundaries with FRCC RE; (ii) transferring to SERC will have no impact on operations of transferring registered entities; (iii) SERC plans to increase staffing and resources; and (iv) given existing and planned coordination between SERC and FRCC RE, there will be no gaps in oversight of compliance monitoring and enforcement ("CMEP") activities related to the transferring registered entities. As a result, the effectiveness and efficiency of the ERO Enterprise's administration of reliability would best be served by approval of SERC as Transferee Regional Entity.

VII. REQUEST FOR SPECIAL ASSESSMENT AND WAIVER OF NERC RULE OF PROCEDURE 1107

In Order No. 672, the Commission stated that for "the ERO to request emergency funding," NERC may request FERC approval for special assessments "[o]n a demonstration of unforeseen and extraordinary circumstances …. Such filing shall include supporting materials to justify the requested funding." **Exhibit E** of the FRCC RDA similarly states that, "[d]uring the course of the fiscal year, if FRCC determines it does not or will not have sufficient funds to carry out its

Order").
[16] March 2011 Order at P 10.
[17] *Id*. at P 8.
[18] *Id*.

delegated functions and related activities, FRCC shall submit to NERC one or more proposed amended or supplemental business plans and budgets and requests for approval."[19]

The "unforeseen and extraordinary circumstance" warranting this request for a Special Assessment was the October 30, 2018, FRCC Board vote to wind down FRCC RE effective July 1, 2019. This vote accelerated the maturation of FRCC's obligation to make retention agreement payments to fourteen (14) key FRCC RE staff and nine (9) key shared corporate staff who are instrumental in maintaining FRCC's execution of its Delegated Authority.

In November 2017, after NERC determined that NERC Regional Entities should be separate corporate entities from NERC registered entities, FRCC RE and corporate employees voiced concerns about their uncertain employment. To reassure staff that FRCC would continue to fulfill its mission to assure reliability, and to retain staff through December 31, 2019, FRCC offered certain employees retention agreements that included a modest retention payment to be paid if they stayed through December 31, 2019.

In February 2018, the FRCC board decided to postpone a determination regarding dissolution of FRCC RE causing FRCC to lose staff. As a result, FRCC offered amended retention agreements guaranteeing employment at least through December 31, 2020, as well as additional completion payments to be paid on or before January 31, 2021. When the FRCC Board approved FRCC's 2019 budget in June 2018, it had not anticipated that the Regional Entity division would cease to exist in 2019. Rather, FRCC's Commission-approved 2019 budget only reflected reduced Regional Entity staff and an attrition factor, and assumed only the modest retention payments that FRCC had offered its key RE and corporate employees in November 2017.

Despite these amended retention agreements in February 2018, FRCC continued to receive

[19] *See also* Section 1108 of the NERC ROP.

staff resignations. Needing to address the cumulative impact of staff resignations and to ensure FRCC could continue to meet its responsibilities under the RDA, FRCC again amended the retention agreements in June 2018. The second amended retention agreements introduced periodic retention payments earned if an employee remained employed on July 31, 2019 and then again on July 31, 2020. These enhanced retention agreements also offered employees a more significant payment if they remained employed at FRCC until the FRCC Board of Directors made and fully implemented a final decision as to the future of the RE. These retention agreements were unanimously approved by FRCC's full stakeholder board, representing the registered entities that will ultimately pay the expense. These enhanced retention agreements did what they were intended to do, and FRCC has received no additional resignations since implementing the enhanced agreements.

In October 30, 2018, FRCC Board decided to seek dissolution of the FRCC RE by July 1, 2019. As a result of the proposed dissolution in 2019, FRCC faced an accelerated obligation to pay out retention payments in lump sums in 2019. All retention payments under the enhanced agreements will be due and owing to FRCC RE and FRCC corporate staff on August 31, 2019, as opposed to being spread throughout 2019, 2020, and ending in early 2021. These agreements amount to approximately $3,020,000 of retention and other payroll related costs. Payment of these retention agreements creates a cash flow issue for FRCC in mid-2019 when the first retention payments are owed to staff. Accordingly, FRCC requests that a Special Assessment be approved in the amount up to $630,000 based on current cash flow projections. The calculation of the Special Assessment amount will take into account all cash flow available to FRCC by August 2019.

NERC also requests the Commission's express approval to deviate from any applicable rules and policies, including Section 1107 of the NERC ROP, as needed, to permit use of penalty

payments for FRCC RE wind down and SERC transition costs, in order to limit the amount of the Special Assessment.

VIII. BUDGET, COMPLIANCE AND ENFORCEMENT TRANSFER ANALYSIS

Apart from the Special Assessment discussed above in **Section VII**, all budgetary and assessment impacts of FRCC RE's dissolution and wind down will be reflected in the customary budget cycle process as follows:

(1) unaudited quarterly financial statements for all quarters leading up to and including the Termination Effective Date,

(2) a reconciliation of budgeted to actual expenditures for the 2019 FRCC RE and SERC Commission-approved budgets,[20] and,

(3) the 2020 Business Plan and Budget for SERC which will be filed by NERC on or around August 24, 2019.

The following sections discuss budgetary impacts of the Proposed Transaction on SERC.

a. Budget and Resource Ramifications of the Transfers on SERC

By assuming Delegated Authority for the registered entities transferring to SERC from FRCC RE, SERC anticipates an increase in costs for 2019 and beyond. NERC requests that SERC apply the FRCC RE third and fourth quarter assessments in 2019 as well as SERC penalty monies towards the costs of assuming FRCC RE's Delegated Authority. If the Commission approves the Special Assessment, NERC requests the Commission's approval for FRCC to transfer to SERC the RE third quarter assessment money by August 31, 2019, and fourth quarter assessment money by October 31, 2019.[21] NERC also requests the Commission's approval to deviate from Section

[20] Pursuant to the Termination Agreement, NERC will receive from FRCC a true-up of actual and budgeted expenses for 2019 120 days after the Termination Effective Date. NERC will, in the normal course, file with FERC the true-up filings for 2019 for NERC, FRCC RE, and SERC.

[21] This is contingent upon the Commission's approval of the Special Assessment.

1107[22] of the NERC ROP to allow SERC to apply, as needed, penalties received by SERC between July 1, 2018 and December 31, 2019, towards the costs associated with its assumed Delegated Authority over FRCC RE's registered entities.[23] NERC will continue to monitor and evaluate the plans and progress of SERC and FRCC in executing the transitions and wind-down of Regional Entity activities, using approved assessment funding, reserves, and other funding sources

In 2020, SERC will include the impacts of FRCC RE's transferred Delegated Authority in SERC's business plan and budget. For 2019, SERC anticipates approximately $4.8 million to $5.2 million in one-time costs to accommodate the transfer of additional registered entities. Annual steady state costs thereafter are anticipated to be in the range of $4.5 million to $5.5 million. Additionally, SERC anticipates adding an additional 17 to 21 full-time staff to manage the additional work associated with SERC's assumption of Delegated Authority over the transferring registered entities.

b. Compliance and Enforcement Ramifications of the Transfers

After reviewing the transition plans and holding discussions with FRCC and SERC, NERC believes that the steps outlined in the Proposed Transaction sufficiently mitigate the risk of material gaps in oversight of compliance monitoring and enforcement activities resulting from the transfers of the FRCC RE registered entities to SERC. Regarding the transfer of the FRCC RE

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[22] NERC Rule of Procedure Section 1107.2 provides the following:

> All funds from financial Penalties assessed in the United States received by the entity initiating the compliance monitoring and enforcement process shall be applied as a general offset to the entity's budget requirements for the subsequent fiscal year, if received by July 1, or for the second subsequent fiscal year, if received on or after July 1. Funds from financial Penalties shall not be directly applied to any program maintained by the entity conducting the compliance monitoring and enforcement process. Funds from financial Penalties assessed against a Canadian entity shall be applied as specified by legislation or agreement.

Emphasis added.

[23] *See* NERC Rule of Procedure Section 1107.4.

registered entities' compliance history, SERC and FRCC RE use the same Compliance Issues Tracking System ("CITS") data platform. SERC plans to access FRCC's CITS data of the registered entities. Preliminary activities associated with these transfers are ongoing. The transfer of the compliance history data will assist in a seamless transition for FRCC RE registered entities and provide SERC with registered entity CMEP history needed for compliance monitoring and enforcement of the transferred registered entities going forward.

SERC's estimated full time equivalent increases appear to be reasonable and appropriate to accommodate the increased workloads associated with the transfers. The Petitioners will ensure that any previously scheduled audits are performed for appropriate RCs, BAs and TOPs transferring from the FRCC RE and will review the audit schedule for other FRCC RE registered entities to assess and to identify any areas of risks that would warrant audits in 2019. SERC will develop an annual CMEP Implementation Plan for 2020, including a compliance audit and spot check schedule, which will include the transferred registered entities. The compliance audit schedule and coverage will take into account the transferred registered entities' previous audit histories as well as Inherent Risk Assessments previously prepared by the FRCC RE for the transferred registered entities.

Expedited Commission review of this Petition and Commission approval to transfer the registration of FRCC RE registered entities on July 1, 2019, will provide FRCC and the Petitioners the ability to timely complete the transfer of files, documents and other information necessary for SERC to assume CMEP responsibilities for the transferring FRCC RE registered entities. NERC will oversee all transition activities to ensure that Regional Entities meet statutory obligations and that there are no gaps in reliability oversight or enforcement during, or as a result of, the transition.

IX. AMENDMENT TO THE SERC REGIONAL DELEGATION AGREEMENT

The transfer of all 36 FRCC RE registered entities to SERC expands the boundaries of

SERC. To reflect the transfer of the FRCC RE registered entities to SERC, NERC and SERC propose to amend Exhibit A – Regional Boundaries to the RDA with SERC (see **Attachment 2 and Attachment 3**).[24] Exhibit A to the RDAs describes the geographic boundaries of a Regional Entity.[25] The regional boundary description in Exhibit A is merely an illustration of the geographic areas included in a given Regional Entity. There are no other amendments required to the SERC RDA.

X. AMENDMENTS TO THE SERC BYLAWS

The petitioners request the Commission's approval of the proposed amendments to the SERC Bylaws. These revisions accommodate the integration of the FRCC RE into the SERC Region. **Attachment 4 and Attachment 5** to this petition are clean and redline versions, respectively, of the revised SERC Bylaws.

a. Proposed Amendments to the SERC Bylaws

There are proposed changes to two provisions of the SERC Bylaws: (i) Section 6.1 - Executive Committee Representatives; and (ii) Section 4.7 - Election of Board Officers and Executive Committee. Each one of those is discussed below.

(1) Section 6.1 Executive Committee Representatives

SERC proposes to add three (3) seats to its Board Executive Committee ("BEC") in the three (3) sectors noted below to ensure that FRCC entities can fully integrate and engage in SERC Board activities from the outset. SERC proposes to change the number of representatives on the BEC from twelve (12) to fifteen (15). Specifically, SERC proposes to increase the number of representatives from the Investor Owned Utility ("IOU") sector from three (3) to four (4), increase

[24] Attachments 2 and 3 are, respectively, clean and redlined versions of the proposed amended version of the SERC RDA.
[25] The boundaries depicted in the various RDAs are illustrative. The scope of each Regional Entity's jurisdiction is provided for in the NERC Compliance Registry.

the number representatives from the Cooperative sector from two (2) to three (3), and increase the number of representatives from the Municipal sector from two (2) to three (3).

(2) Section 4.7 Election of Board Officers and Executive Committee

SERC proposes to divide the BEC members into two groups and introduce staggered terms (i.e., alternating terms for Group 1 and Group 2) to mitigate the risk that the entire BEC could turn over at the same time. Specifically, SERC proposes to modify the language in paragraph 2 to introduce staggered, two-year terms. The first group would serve an initial three-year term and then two-year terms thereafter. The second group would serve an initial two-year term and then two-year terms thereafter. By adding incoming FRCC members to the BEC on July 1, 2019, the staggered terms would not disrupt the current term for current BEC members which ends on June 30, 2020. Furthermore, it would give the incoming FRCC BEC members the ability to serve the remaining year of the current term (from July 1, 2019 to June 30, 2020) on the BEC. Thereafter, the guaranteed incoming three (3) FRCC BEC members would be added to Group 1, which would allow them to serve an additional three-year term beginning on July 1, 2020, and ending on June 30, 2023. This would guarantee the FRCC entities four (4) consecutive years on the BEC in order to support a seamless integration of FRCC registered entities on the SERC Board. FRCC registered entities are also free to run for any other BEC seats for which they are eligible.

b. SERC and NERC Approvals of the Proposed Amendments

The SERC Board conditionally approved the proposed amendments to the SERC Bylaws on October 24, 2018 (conditioned on the FRCC Board's approval during its October 30, 2018, meeting to dissolve the FRCC RE). The FRCC Board approved dissolving the FRCC RE on October 30, 2018, consistent with the terms presented to the board, thereby satisfying the condition for SERC's Board approval of the proposed Bylaws amendments. The NERC Board approved the proposed amendments on February 7, 2019, as part of the Proposed Transaction.

XI. EXCEPTION FROM REGIONAL RELIABILITY STANDARD PRC-006-SERC-02

SERC will not subject former FRCC RE Registered Entities to compliance with *SERC Regional Reliability Standard PRC-006-SERC-02* in favor of continued compliance and enforcement of *NERC Reliability Standard PRC-006-3*. Based on Florida's peninsular nature with limited ties to the rest of the Eastern Interconnection, the FRCC Planning Coordinator has developed an Automatic Underfrequency Load Shedding program with requirements based on the technical design criteria of maintaining a radial transmission network intact during large scale electrical system disturbances within peninsular Florida. The current FRCC Planning Coordinator program specifically coordinates with intentional islanding schemes for peninsular Florida and is supported by extensive technical evaluations and historical experience. These factors were not considered during development of *Regional Reliability Standard PRC-006-SERC-02*. In addition, the current version of *Regional Reliability Standard PRC-006-SERC-02*, along with its development history, has a geographical applicability that excludes peninsular Florida entities.

As a result, the Petitioners intend for SERC to: (i) monitor the FRCC RE registered entities' compliance with *NERC Reliability Standard PRC-006-3 – Automatic Underfrequency Load Shedding* – to which the FRCC RE Registered Entities are already subject; and (ii) exclude FRCC RE registered entities from applicability of *Regional Reliability Standard PRC-006-SERC-02*, upon their transfer to SERC, until the Regional Reliability Standard is reviewed through the SERC Regional Reliability Standards Development Procedure. This approach will continue to support reliability.

Based on the above and in the interest of reliability, SERC will also review *Regional Reliability Standard PRC-006-SERC-02*, with a specific assessment of BES performance

incorporating the existing or revised FRCC Planning Coordinator Underfrequency Load Shedding program elements in lieu of immediate application of the Regional Standard to peninsular Florida entities, no later than its next anticipated five-year review deadline, January 1, 2023. Former FRCC RE registered entities will then have an additional three (3) years to implement any changes to their obligations under the Reliability Standard. This will provide affected entities sufficient lead time to reset relays in the field, if they are determined to be needed.

XII. CONCLUSION

For the reasons set forth above, the Petitioners respectfully request that the Commission approve the Proposed Transaction as outlined in this Petition, after review on an expedited basis with a shortened comment period of no more than 14 days, to allow the issuance of an order in this proceeding within 60 days of the date of this filing and to allow the Proposed Transaction to proceed to completion.

Respectfully submitted,

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ATTACHMENT 1

Termination Agreement for the Amended and Restated Delegation Agreement between the North American Electric Reliability Corporation and Florida Reliability Coordinating Council, Inc.

TERMINATION AGREEMENT FOR THE AMENDED AND RESTATED DELEGATION AGREEMENT BETWEEN THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION AND FLORIDA RELIABILITY COORDINATING COUNCIL, INC.

THIS AGREEMENT ("Termination Agreement"), by and between the North American Electric Reliability Corporation ("NERC") and Florida Reliability Coordinating Council, Inc. ("FRCC") (collectively the "Parties") is intended to provide for the following: (i) the termination of the *Amended and Restated Delegation Agreement between North American Electric Reliability Corporation and Florida Reliability Coordinating Council, Inc*. ("RDA") entered into on January 1, 2016, including, without limitation, the responsibilities and obligations of NERC and FRCC thereunder, (ii) an orderly and organized wind-down and dissolution of the activities of the FRCC Regional Entity ("FRCC RE"), a division of FRCC, and, (iii) an orderly and seamless transition of FRCC's Delegated Authority as set forth in the RDA (the "FRCC Delegated Authority") to SERC Reliability Corporation ("SERC," which the Parties intend to serve as the sole successor Regional Entity and sometimes referred to herein as the "Transferee Regional Entity"). Capitalized terms used in this Termination Agreement that are not defined herein shall have the same meaning as in the RDA or, if not defined in the RDA, shall have the meaning defined in Appendix 2 (*Definitions Used in the Rules of Procedure*) of the NERC Rules of Procedure.

RECITALS

I. NERC and FRCC entered into an RDA, effective as of January 1, 2016, wherein NERC and FRCC agreed that FRCC would carry out Delegated Authority and delegation-related activities in furtherance of NERC's responsibilities as the Electric Reliability Organization ("ERO") under Subtitle A of the Electricity Modernization Act of 2005

which added Section 215 to the Federal Power Act (16 U.S.C. § 824o) (the "Act").

II. NERC and FRCC have mutually agreed to terminate the RDA and to terminate the FRCC RE's status and activities as the Regional Entity for the FRCC Region.

III. The Parties desire an orderly and seamless transfer and transition of the FRCC Delegated Authority to SERC.

NOW, THEREFORE, in consideration of the mutual covenants and agreements contained in this Termination Agreement, NERC and FRCC, intending to be bound, agree as follows:

1. The Parties propose that the terms of the Termination Agreement become effective as of the date upon which the Federal Energy Regulatory Commission (the "Commission") approves this Termination Agreement (such date, the "Effective Date") in substantially the form proposed.
2. FRCC RE shall cease to exist as a Regional Entity and complete wind down of its business on August 31, 2019 (the "Termination Effective Date").
3. The Parties agree to engage in such of the activities contemplated by this Termination Agreement according to the terms specified herein, with the objective of terminating the RDA and transferring the FRCC Delegated Authority to SERC.
4. Termination of the RDA is subject to (i) the Commission's approval of this Termination Agreement, as proposed, and (ii) NERC and FRCC completing their respective obligations that are specified in this Termination. Agreement.
5. Unless otherwise specified herein, NERC must complete and document the following activities by the Termination Effective Date:
    a. Issue a determination specifying that by July 1, 2019, SERC shall be the Transferee Regional Entity for all Registered Entities in the FRCC Region,

subject to the Commission's approval.

b. Seek approval to amend the SERC Bylaws to include revisions to: (i) Section 6.1 Executive Committee Representatives to add three seats for integration of FRCC entities; and (ii) Section 4.7 Election of Board Officers and Executive Committee to introduce staggered terms for two groups of Board Executive Committee members.

c. Based on the determinations made pursuant to Section 3.a of this Termination Agreement, NERC shall identify the Load-Serving Entity ("LSEs") in the FRCC Region and specify that those LSEs shall, as of the Termination Effective Date, be included as LSEs within SERC for purposes of determining, allocating, and billing NERC statutory funding assessments.

d. Assist with the transition of all compliance and enforcement processes for Registered Entities in the FRCC Region to SERC by July 1, 2019.

e. Request and obtain Commission approval of a petition providing for the following:

    i. the funding of the wind-down costs for FRCC beyond FRCC's expected available cash[1] as of July 1, 2019, including costs associated with payments due under retention agreements for key FRCC RE employees and key shared corporate employees supporting the FRCC RE for its wind down. In addition to expected available cash, FRCC will use the following to fund its wind down costs:

[1] "Available cash" means any available working capital attributed to the RE's operations not needed for current or anticipated costs through the termination date and wind-down, including excess funds from Q1 and Q2 2019 assessments and prior year budget variances.

1. a Special Assessment,
2. FRCC RE penalties[2] processed and submitted[3] between July 1, 2018, and December 31, 2019, and,
3. first and second quarter assessment funds in 2019.

ii. a Special Assessment, with appropriate supporting budget and other information provided to NERC by FRCC.

iii. deviate from any applicable rules and policies, including Section 1107 of the NERC Rules of Procedure ("ROP"), as needed, to permit use of Penalty payments processed and submitted to NERC between July 1, 2018 and December 31, 2019 as follows:

1. Penalties processed and submitted between July 1, 2018 and July 1, 2019, for FRCC to use to pay for the costs of the wind-down and dissolution of the FRCC RE; and,
2. Penalty monies processed and submitted between July 1, 2019, and December 31, 2019, or not otherwise applied towards wind-down costs, to be reimbursed to FRCC entities on a pro-rata basis.

iv. deviate from any applicable rules and policies, as needed, to permit the following treatment of assessments:

[2] FRCC penalties are defined as penalties associated with instances of noncompliance with Reliability Standards by FRCC RE entities that were part of the FRCC RE caseload prior to the date in which entities are transferred to SERC. The definition does not include any noncompliance by FRCC in its capacity as a Reliability Coordinator or Planning Authority.

[3] Processed and submitted shall mean penalties for FRCC entities billed but not yet collected, penalties for FRCC entities pending Commission approval, and penalties for FRCC entities submitted to NERC and pending NERC Board of Trustees Compliance Committee approval.

1. apply Commission-approved 2019 FRCC first and second quarter assessments towards the wind-down costs of FRCC RE; and,
2. transfer Commission-approved 2019 FRCC third and fourth quarter assessments to SERC by August 31, 2019 and October 31, 2019, respectively, contingent upon the approval of the Special Assessment.

v. exemption of the FRCC RE Registered Entities from compliance with *Regional Reliability Standard PRC-006-SERC-02* in favor of continued enforcement of *NERC Reliability Standard PRC-006-3 – Automatic Underfrequency Load Shedding* until such time as the Regional Reliability Standard is reaffirmed or revised through the SERC Regional Reliability Standards Development Procedure. If the FRCC entities later become subject to *SERC Reliability Standard PRC-006-SERC-02* as a result of the SERC Regional Reliability Standards Development Procedure, FRCC entities shall have three (3) years to comply.

vi. this Termination Agreement and any other agreements, documents, or proposed actions necessary to effectuate the termination of the RDA, the transfer of Registered Entities in the FRCC Region to SERC, and the transfer and transition of the FRCC Delegated Authority to SERC.

vii. approval of any NERC governance or internal process documents to which amendments are necessary or appropriate to account for or reflect the dissolution of the FRCC RE and the termination of the RDA.

f. Amend the SERC bylaws to account for or to reflect the dissolution of the FRCC

RE and the termination of the NERC-FRCC RDA and submit the amended SERC bylaws to the NERC Board of Trustees and the Commission for approval.

g. Coordinate with FRCC to ensure appropriate disconnection of any internet, computer, or software interfaces and connections that FRCC or employees or contractors of FRCC or FRCC RE have with NERC and/or with any other Regional Entity by reason of the FRCC RE Delegated Authority. The requirements of this section will not extend to any internet, computer, or software interfaces and connections that FRCC or its employees or contractors maintain in connection with FRCC's status and functions as a Registered Entity.

h. Subsequent to the Termination Effective Date, take any other steps required in connection with the dissolution and wind down of the FRCC RE and the termination and transfer of the FRCC RE Delegated Authority to SERC, as the Transferee Regional Entity, including, submitting to the Commission any required reconciliations of the FRCC RE's budgeted to actual expenditures per the annual business plan and budget process and schedule; and,

i. Verify the completion of the steps identified in this section of the Termination Agreement through a certification signed by an officer of NERC. The certification shall be submitted to FRCC no later than one hundred and fifty (150) days following the Termination Effective Date.

6. Unless otherwise specified, by the Termination Effective Date, FRCC must complete the following activities:

a. Assist with the transition of any relevant files, documents, records, and other information pertaining to the FRCC Delegated Authority to SERC or to NERC, in compliance with Section 12(c) of the RDA. As used in this Termination

Agreement, "files, documents, records and other information" shall be construed broadly and, without limiting the foregoing, shall include all material maintained or stored in any form or format, including in paper form or in electronic media, that is still subject to regulatory retention requirements.

b. Without limiting the generality of this requirement, transfer to SERC, as the Transferee Regional Entity, all relevant files, documents, records, and other information relating to:

   i. any regional reliability standards development projects in progress as of the Termination Effective Date;

   ii. registration of Registered Entities in the FRCC Region;

   iii. completed and in-progress certification activities for Registered Entities (Reliability Coordinators, Balancing Authorities and Transmission Operators) in the FRCC Region;

   iv. FRCC RE's completed or in-progress compliance monitoring and enforcement activities with respect to the Registered Entities in the FRCC Region;

   v. completed Technical Feasibility Exception Requests ("TFE Requests") and Material Change Reports submitted by Registered Entities in the FRCC Region;

   vi. in-progress reviews of TFE Requests and Material Change Reports submitted by Registered Entities in the FRCC Region; and

   vii. FRCC RE's monitoring of the progress of Registered Entity with approved TFE Requests in implementing compensating and mitigating measures and in achieving Strict Compliance with the Applicable

Requirement;

viii. previously-reviewed and in-progress Bulk Electric System Exception Requests submitted by Registered Entities in the FRCC Region;

ix. previously-completed and in-progress reliability assessments (e.g., annual long-term reliability assessments, seasonal reliability assessments, and special reliability studies) of the FRCC Region (whether conducted as an assessment solely of the FRCC Region or as part of an assessment of a broader region, including the entire North American Bulk Power System); and

x. previously-completed and in-progress analyses, in which FRCC RE participated, of system events occurring in the FRCC Region.

c. Submit to NERC detailed descriptions or estimates of the reallocation of any Commission-approved 2018 and/or 2019 assessment funds for the wind-down and dissolution of the FRCC RE and the termination and transfer of the FRCC Delegated Authority, including completion of the obligations set forth in this Agreement and other revenue sources for the FRCC RE on April 1, 2019 and on May 1, 2019. NERC will use this information, as needed, to support any filings with the Commission necessary in connection with the termination and transfer of the FRCC Delegated Authority.

d. Provide NERC the estimated value of FRCC penalties processed and submitted and to be applied to reduce the Special Assessment by May 1, 2019.

e. Use any Special Assessment authorized by the Commission to pay for wind down costs, including the above-referenced retention agreements for fourteen (14) FRCC RE staff and nine (9) key shared corporate staff upon dissolution of

FRCC RE.

f. Submit to NERC unaudited quarterly financial reports for all 2019 quarters leading up to and including the Termination Effective Date.

g. Submit to NERC, by April 1, 2020, audited financial statements for the FRCC RE for 2019.

h. Submit to NERC, by April 1, 2020, a reconciliation of actual expenditures for the FRCC RE for 2019 as compared to the Commission-approved FRCC RE budget for 2019.

i. Verify the completion of the steps identified in this section of the Termination Agreement through a certification signed by an officer of FRCC no later than one hundred and fifty (150) days following the Termination Effective Date.

7. All notices, demands, requests, and other communications required or permitted by or provided for in this Termination Agreement shall be given in writing to FRCC or NERC, at the respective addresses set forth below, or at such other address as FRCC or NERC shall designate for itself in writing in accordance with this Section 5, and shall be delivered by hand, reputable overnight courier, or e-mail which is verified as being received:

If to FRCC:

Attn: Stacy Dochoda
President and Chief Executive Officer
Florida Reliability Coordinating Council, Inc.
3000 Bayport Drive, Suite 600
Tampa, Florida 33607
sdochoda@frcc.com

If to NERC:

Attn: James B. Robb
President and Chief Executive Officer

North American Electric Reliability Corporation
3353 Peachtree Road NE, Suite 600 – North Tower
Atlanta, GA 30326
Jim.Robb@nerc.net

8. Neither this Termination Agreement nor any of the terms hereof may be amended unless such amendment is made in writing, signed by FRCC and NERC, and approved by the Commission.
9. This Termination Agreement constitutes the entire agreement on its subject matter, and supersedes all prior agreements and understanding, both written and oral, between FRCC and NERC as to the subject matter of this Termination Agreement.
10. This Termination Agreement may be executed in counterparts and each counterpart shall have the same force and effect as the original.
11. The following provisions of the RDA shall survive its termination:
    a. Section 13 (Limitation of Liability),
    b. Section 14 (No Third-Party Beneficiaries),
    c. Section 15 (Confidentiality), provided, however, that FRCC or NERC may transfer Confidential Information to SERC, as the Transferee Regional Entity, in accordance with this Termination Agreement, and,
    d. Exhibit E (Funding) - Section 8 (NERC Review of Regional Entity Financial Records), provided, that NERC's rights under Exhibit E – Section 8 shall survive for twelve (12) months following the Termination Effective Date.

NOW, THEREFORE, FRCC and NERC have caused this Termination Agreement to be executed by their duly authorized representatives, to be effective as of the Effective Date.

1.0 Regional Boundaries

The geographic boundaries of SERC Reliability Corporation (SERC) are determined by the service areas of its membership, comprised of investor-owned utilities, municipal, cooperative, state and federal systems, merchant electricity generators, and power marketers.

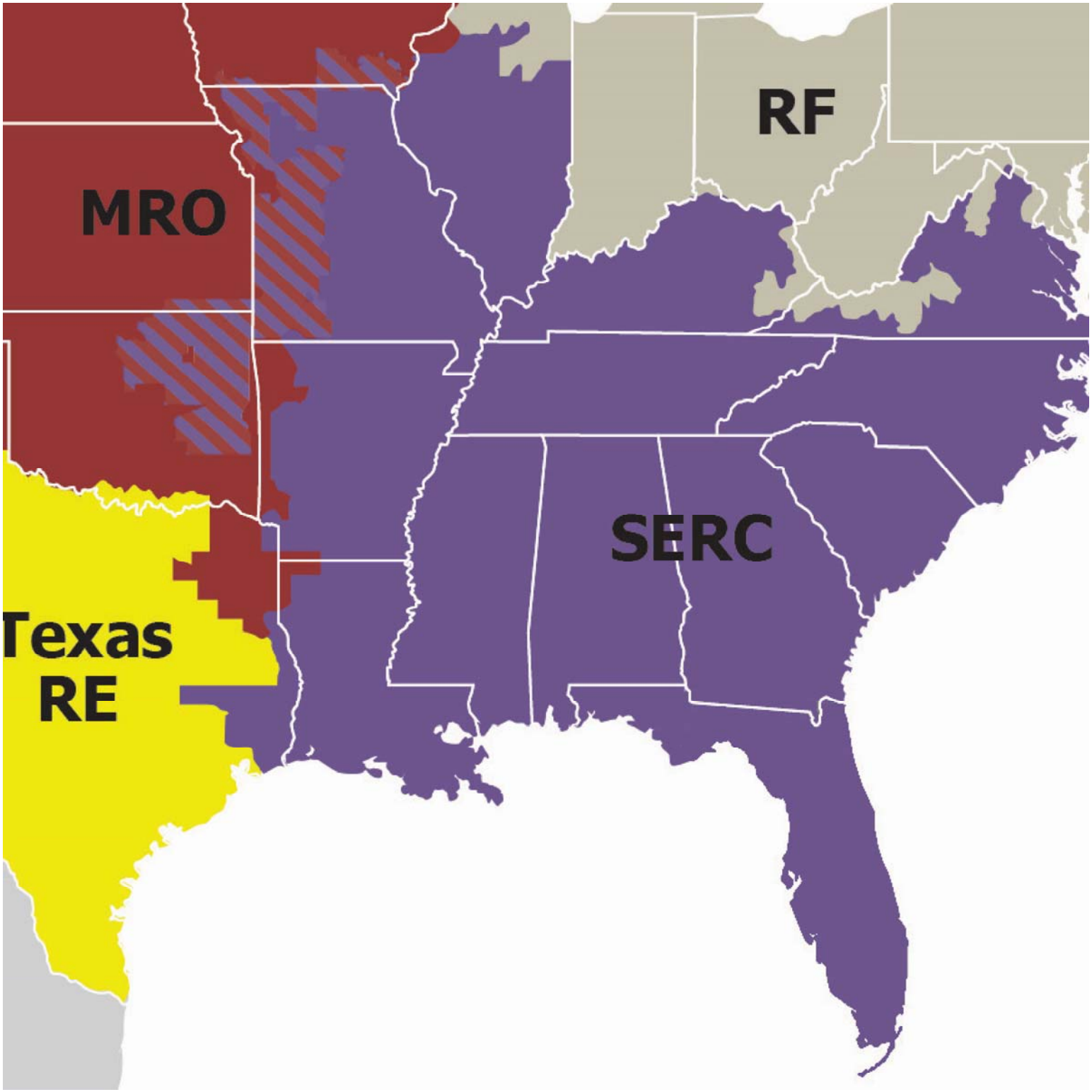
SERC covers an area of approximately 630,000 square miles in sixteen states: all of Alabama, Florida, Georgia, Mississippi, North Carolina, South Carolina; most of Arkansas, Louisiana, Missouri, and Tennessee; and portions of Illinois, Iowa, Kentucky, Oklahoma, Texas, and Virginia.

Service provided by SERC members in areas which overlap with neighboring regions include:

- The area in southern Iowa is served by N.E. Missouri Electric Power Cooperative, a member of Associated Electric Cooperative, Inc., and N.W. Electric Power Cooperative, a member of Associated Electric Cooperative, Inc.
- The area in eastern Oklahoma is served by KAMO Electric Cooperative, Inc., a member of Associated Electric Cooperative, Inc.
- The area in western Missouri is served by N.W. Electric Power Cooperative, a member of Associated Electric Cooperative, Inc., and KAMO Electric Cooperative, Inc., a member of Associated Electric Cooperative, Inc.

A regional map is show in Section 1.1.

SERC may also perform compliance and enforcement activities outside of the Regional Entity, on behalf of NERC and/or other Regional Entities, such activities to be undertaken pursuant to a contract between the Regional Entities that is approved by the SERC Board, the NERC Board, and the Federal Energy Regulatory Commission.


RF
MRO
SERC
Texas
RE

1.0 Regional Boundaries

The geographic boundaries of SERC Reliability Corporation (SERC) are determined by the service areas of its membership, comprised of investor-owned utilities, municipal, cooperative, state and federal systems, merchant electricity generators, and power marketers.

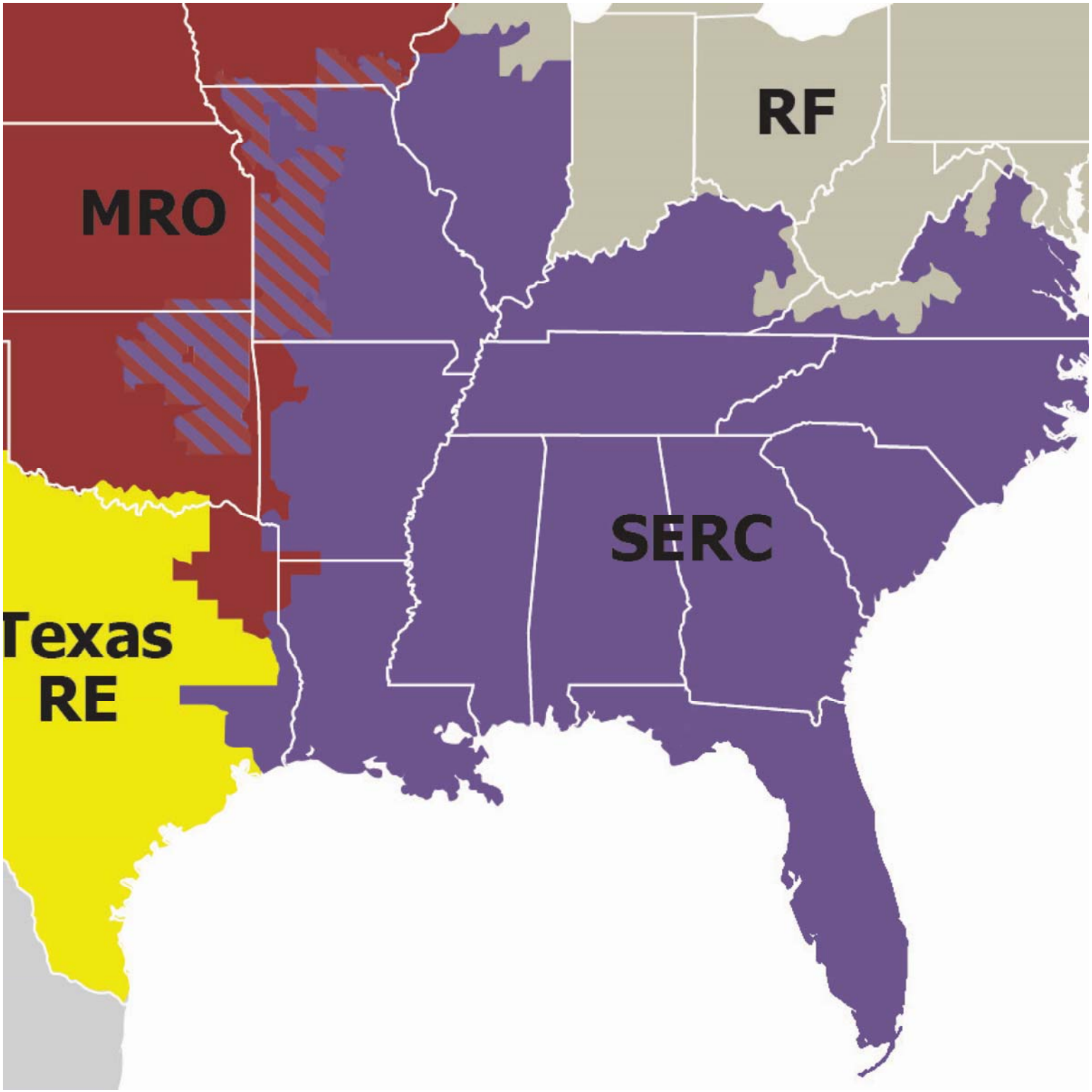
SERC covers an area of approximately ~~574,000~~630,000 square miles in sixteen states: all of Alabama, Florida, Georgia, Mississippi, North Carolina, South Carolina; most of Arkansas, Louisiana, Missouri, and Tennessee; and portions of ~~Florida,~~ Illinois, Iowa, Kentucky, Oklahoma, Texas, and Virginia.

Service provided by SERC members in areas which overlap with neighboring regions include:

- The area in southern Iowa is served by N.E. Missouri Electric Power Cooperative, a member of Associated Electric Cooperative, Inc., and N.W. Electric Power Cooperative, a member of Associated Electric Cooperative, Inc.
- The area in eastern Oklahoma is served by KAMO Electric Cooperative, Inc., a member of Associated Electric Cooperative, Inc.
- The area in western Missouri is served by N.W. Electric Power Cooperative, a member of Associated Electric Cooperative, Inc., and KAMO Electric Cooperative, Inc., a member of Associated Electric Cooperative, Inc.
- ~~The area in N.E. Florida (part of Baker and Nassau counties) served by Okefenoke Rural Electric Membership Corporation (OREMC), a member of Georgia System Operations Corporation; and facilities physically located in Baker County, Florida owned by Georgia Transmission Corporation (GTC) are part of the SERC Region and not the FRCC Region.~~

A regional map is show in Section 1.1.

SERC may also perform compliance and enforcement activities outside of the Regional Entity, on behalf of NERC and/or other Regional Entities, such activities to be undertaken pursuant to a contract between the Regional Entities that is approved by the SERC Board, the NERC Board, and the Federal Energy Regulatory Commission.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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

ATTACHMENT 4

Transfer of Delegated Authority over Florida Reliability Coordinating Council RE Registered Entities to SERC

Transfer of Delegated Authority over Florida Reliability Coordinating Council RE Registered Entities to SERC

Following the mutual decision reached by the North American Electric Reliability Corporation ("NERC") and Florida Reliability Coordinating Council ("FRCC") to terminate the Delegated Authority of the FRCC Regional Entity ("FRCC RE") division of FRCC, NERC, as the Electric Reliability Organization ("ERO") identifies SERC Reliability Corporation ("SERC") as the Regional Entity that will assume FRCC RE's Delegated Authority over all registered entities in FRCC RE's footprint. When reviewing this transfer of Delegated Authority, under the guidance of Section 1208 of the NERC Rules of Procedure ("ROP") as well as Federal Energy Regulatory Commission precendent, NERC considered the following:

(1) the location of the Registered Entity's Bulk Power System facilities in relation to the geographic and electrical boundaries of the transferee Regional Entity;

(2) the impact of the proposed transfer on other Bulk Power System owners, operators, and users, including affected Reliability Coordinators ("RC"), Balancing Authorities ("BA"), and Transmission Operators ("TOP"), as appropriate;

(3) the impact of the proposed transfer on the current and future staffing, resources, budgets and assessments to other Load-Serving Entities of the transferee Regional Entity;

(4) the sufficiency of the proposed transferee Regional Entity's staffing and resources to perform compliance monitoring and enforcement activities with respect to the Registered Entity;

(5) the Registered Entity's compliance history with FRCC RE; and the manner in which pending compliance monitoring and enforcement matters concerning the Registered Entity would be transitioned from SPP to the transferee Regional Entity; and,

(6) any other reasons NERC and the transferee Regional Entity consider relevant.

Below is a complete list of the Registered Entities that NERC proposes to transfer from FRCC RE's footprint to SERC's footprint.

NCR ID#	Entity Name	Proposed Regional Entity
NCR00003	Bartow, City of	SERC
NCR00004	Beaches Energy Services of Jacksonville Beach	SERC
NCR11010	City of Leesburg	SERC
NCR00054	City of Ocala Electric Utility	SERC
NCR00063	Duke Energy Florida, LLC	SERC
NCR00021	Florida Keys Electric Cooperative Assn	SERC
NCR00022	Florida Municipal Power Agency	SERC
NCR00023	Florida Municipal Power Pool	SERC
NCR00024	Florida Power & Light Co.	SERC
NCR00025	Florida Public Utilities Company	SERC
NCR00026	Florida Reliability Coordinating Council	SERC
NCR00464	Florida Reserve Sharing Group	SERC
NCR00027	Fort Pierce Utilities Authority	SERC
NCR00032	Gainesville Regional Utilities	SERC
NCR00069	General Electric International - Shady Hills	SERC
NCR11875	GenOn Florida	SERC
NCR00035	Hardee Power Partners Limited	SERC
NCR00037	Homestead, City of	SERC
NCR00039	Indiantown Cogeneration LP	SERC
NCR00040	JEA	SERC
NCR00041	Key West, City of (Keys Energy)	SERC

NCR00042	Kissimmee Utility Authority	SERC
NCR00043	Lake Worth, City of	SERC
NCR00044	Lakeland Electric	SERC
NCR00045	Lee County Electric Cooperative, Inc	SERC
NCR00052	New Smyrna Beach, Utilities Commission of	SERC
NCR00057	Orlando Utilities Commission	SERC
NCR10054	Palm Beach Resource Recovery Corporation	SERC
NCR00065	Reedy Creek Improvement District	SERC
NCR00068	Seminole Electric Cooperative	SERC
NCR00071	Southern Power Company	SERC
NCR00073	Tallahassee, City of	SERC
NCR00074	Tampa Electric Company	SERC
NCR00078	Vandolah Power Company, LLC	SERC
NCR00079	Vero Beach, City of	SERC
NCR00081	Winter Park, City of	SERC

The location of the registered entity's BPS facilities in relation to the geographic and electrical boundaries of the transferee Regional Entity

NERC's review began with the NERC U.S. Regions Map.

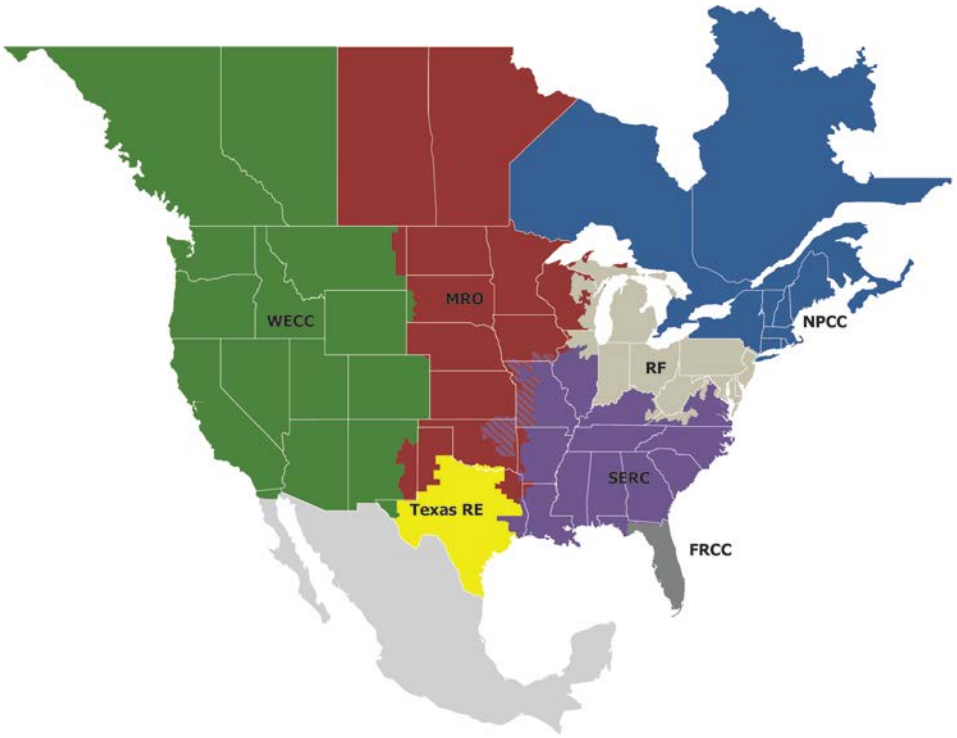

Figure 1: NERC Regions Map[1]

As shown in Figure 1, FRCC RE has geographic boundaries with only one existing Regional Entity- SERC. FRCC is entirely within the geographic boundary of the State of Florida. The FRCC region is comprised of peninsular Florida east of the Apalachicola River with the exception of a small section of

Northeast Florida (Baker and Nassau counties). Areas west of the Apalachicola River are within the SERC region. The FRCC region is within the Eastern Interconnection and is under the direction of the FRCC Reliability Coordinator.

[1] The NERC Regions Map is available at: http://www.nerc.com/AboutNERC/keyplayers/PublishingImages/2017_NERC_Regions_May2017.jpg. Please note that Figure 1 represents the NERC Regional Entity footprints and does not represent the SPP RTO footprint.

The FRCC Region has an electrical boundary with the SERC region. The FRCC region interconnects with the SERC region via eleven (11) Bulk Electric System ("BES") transmission lines. The 11 lines consist of two 500 kV, four 230 kV, and five 115 kV lines. These lines are referred to as the "Florida / Southern Interface." These eleven (11) lines comprise the BES electrical boundary between the RFCC region and the SERC region. The FRCC Region does not have an electrical boundary with any other NERC region.

The impact of the proposed transfer on other BPS owners, operators, and users, including affected RCs, BAs, and TOPs.

NERC must ensure the continuity of functional alignment within geographic or electrical boundaries. Recognizing the importance of interactions between functions to ensure the reliable operation of the BPS, NERC considered the functional relationships between registered entities in FRCC. NERC emphasizes maintaining those relationships within a common Regional Entity footprint to promote the efficient and effective administration of BPS reliability. Transferring the registration of FRCC RE registered entities to SERC does not affect their alignment as all entities in the existing footprint would change registration together on July 1, 2019.

The impact of the proposed transfer on the current and future staffing, resources, budgets and assessments to other Load-Serving Entities of the transferee Regional Entity.

For 2019, SERC anticipates approximately $4.8 milltion to $5.2 million in one-time costs to accommodate the transfer of FRCC RE's registered entities. NERC proposes that SERC will cover these costs through available assessment and penalty funds. NERC does not anticipate any

changes to the assessments of the Load-Serving Entities of SERC, as approved in SERC's 2019 business plan and budget.

The sufficiency of the proposed transferee Regional Entity's staffing and resources to perform compliance monitoring and enforcement activities with respect to the Registered Entity.

SERC's estimated full time equivalent increases appear to be reasonable and appropriate to accommodate the increased workloads associated with the transfer of all FRCC registered entities to SERC in 2019.

The Registered Entity's compliance history with FRCC RE; and the manner in which pending compliance monitoring and enforcement matters concerning the Registered Entity would be transitioned from FRCC RE to the transferee Regional Entity.

NERC and SERC will develop and implement transition plans that will include compliance history and pending compliance monitoring and enforcement matters concerning each registered entity. NERC and SERC will coordinate with the registered entities.

There are currently three FRCC RE registered entities involved in Coordinated Oversight. Two of those entities already have SERC as the Lead Regional Entity ("LRE") while the other has Texas RE as the LRE. There will be no impact to those compliance monitoring and enforcement oversight arrangements.

Any other reasons NERC and the transferee Regional Entity consider relevant.

There are no other reasons NERC considers relevant at this time.

AMENDED AND RESTATED

BYLAWS

OF

SERC RELIABILITY CORPORATION

A North Carolina Nonprofit Corporation

Approved by the SERC Board of Directors on October 24, 2018

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AMENDED AND RESTATED

BYLAWS

OF

SERC RELIABILITY CORPORATION
[Hereinafter referred to as the "Corporation"]

A North Carolina Nonprofit Corporation

ARTICLE I - OFFICES

1.1 **Principal Office**. The principal office of the Corporation shall be located in the City of Charlotte, Mecklenburg County, North Carolina. The Board of Directors may by resolution change the location of this office from time to time.

1.2 **Other Offices**. The Corporation may have other offices at such place or places as the Board of Directors may from time to time appoint or the business of the Corporation may require.

ARTICLE II - MEMBERSHIP

2.1 **General**. The Corporation shall be a membership corporation. Entities that meet the eligibility requirements and apply for membership in the Corporation shall hereinafter be referred to individually as a "Member Company" and collectively as "Member Companies".

2.2 **Eligibility**. Membership in the Corporation is voluntary and is open to any entity in the SERC Region (defined in Section 3.2 below) that is a user, owner or operator of the Bulk Power System, has a material interest in the Bulk Power System in the SERC Region, satisfies the criteria for membership specified in this Section 2.2, qualifies for one or more of the Sectors identified in Section 2.4, and is subject to the jurisdiction of the Federal Energy Regulatory Commission. Membership in the Corporation is predicated on mandatory acceptance of the responsibility to promote, support, and comply with Reliability Standards of the Corporation and the North American Electric Reliability Corporation ("NERC"), and to assist the Corporation in its compliance with the terms and provisions of a Delegation Agreement (a "Delegation Agreement") with NERC, by which NERC delegates authority to propose and enforce Reliability Standards, pursuant to 16 U.S.C. § 824o or the corresponding provisions of any subsequent U.S. Code revisions.

For purposes of these Bylaws, the terms “Bulk Power System”, “Reliability Standards” and “Regional Entity” shall be as defined in 16 U.S.C. § 824o or the corresponding provisions of any subsequent U.S. Code revisions.

2.3 **Termination**. A Member Company may terminate its membership in the Corporation by giving the Board of Directors at least thirty (30) days written notice of its intent to terminate such membership (such Member Companies shall hereinafter be referred to as "Terminated Member Companies"). Terminated Member Companies shall nevertheless continue to be liable for any and all obligations incurred prior to the end of the calendar year in which such notice is given, including, but not limited to, the obligation to pay a pro rata share of any Corporation expense. In addition to termination of membership by the Member Company, the Board of Directors, following notice to the Member Company, may terminate the membership of a Member Company if in the judgment of the Board of Directors that Member Company has violated its obligations and responsibilities to the Corporation. The termination of the membership of a Member Company by the Board of Directors shall require a Supermajority vote, as defined in these Bylaws.

2.4 **Sectors.** Each Member Company shall be classified by the Executive Committee in one of the following seven (7) Sectors (each a “Sector”, and collectively, the “Sectors”):

(a) Investor-Owned Utility Sector – This Sector includes any investor-owned entity with substantial business interest in ownership and/or operation in any of the asset categories of generation, transmission or distribution.

(b) Federal/State Sector – This Sector includes any U.S. federal entity that owns and/or operates electric facilities and/or provides balancing authority services, in any of the asset categories of generation, transmission, or distribution; or any entity that is owned by or subject to the governmental authority of a state and that is engaged in the generation, delivery, and/or sale of electric power to end-use customers primarily within the political boundaries of the state.

(c) Cooperative Sector – This Sector includes any non-governmental entity that is incorporated under the laws of the state in which it operates, is owned by and provides electric service to end-use customers at cost, and is governed by a board of directors that is elected by the membership of the entity; and any non-governmental entity owned by and which provides generation and/or transmission service to such entities.

(d) Municipal Sector – This Sector includes any entity owned by or subject to the governmental authority of a municipality, that is

engaged in the generation, delivery, and/or sale of electric power to end-use customers primarily within the political boundaries of the municipality; and any entity, whose members are municipalities, formed under state law for the purpose of generating or purchasing electricity for sale at wholesale to their members.

(e) Marketer Sector– This Sector includes any entity that is engaged in the activity of buying and selling of wholesale electric power in the SERC Region on a physical or financial basis.

(f) Merchant Electricity Generator Sector – This Sector includes any entity that owns or operates an electricity generating facility or provides balancing authority services for such entities. This includes, but is not limited to, small power producers and all other non-utility producers such as exempt wholesale generators who sell electricity at wholesale.

(g) ISO-RTO Sector – This Sector includes any entity that operates a FERC approved ISO or RTO.

The Executive Committee's classification of a Member Company in a particular Sector may only be changed by the Executive Committee.

2.5 **Transfer of Membership.** A Member Company may not give or otherwise transfer its membership, except to a successor that becomes a Member Company in accordance with the terms and conditions of these Bylaws, and provided that the successor continues to meet its predecessor's obligations.

2.6 **Powers.** Notwithstanding any other provisions of these Bylaws, except for the appointment of Directors as provided in Section 4.2 below, Member Companies shall be non-voting members and shall have no power or authority or right to vote with respect to the actions of the Corporation, specifically including, but not limited to, the dissolution or merger of the Corporation.

ARTICLE III - PURPOSES

3.1 **General Purposes.** The purpose of the Corporation is to promote effective and efficient administration of Bulk Power System reliability in the SERC Region, as defined in Section 3.2. In pursuit of this goal, the Corporation shall:

(a) enter into a Delegation Agreement to serve as a Regional Entity pursuant to 16 U.S.C. § 824o or the corresponding provisions of any subsequent U.S. Code revisions;

(b) promote the development of reliability and adequacy arrangements among the systems in the SERC Region;

(c) participate in the establishment of Reliability Standards;

(d) participate in the measurement of performance relative to these Reliability Standards;

(e) promote conformance to and compliance with these Reliability Standards;

(f) develop and exchange information with respect to planning and operating matters relating to the reliability and adequacy of the Bulk Power System;

(g) review as necessary activities in the SERC Region on reliability and adequacy in order to meet Reliability Standards;

(h) provide a mechanism to resolve disputes on reliability issues in a manner that meets the needs of the parties and the SERC Region; and

(i) provide information with respect to matters considered by the Corporation, where appropriate, to the Federal Energy Regulatory Commission ("FERC") and to other federal and state agencies concerned with reliability and adequacy.

3.2 **Geographic Area.** The Corporation accomplishes its purposes in a geographic area (the "SERC Region") that is defined in Exhibit A of the Amended and Restated Delegation Agreement Between North American Electric Reliability Corporation and SERC Reliability Corporation.

3.3 **Other Statutory Functions.** The Corporation may also perform statutory functions outside of the SERC Region, on behalf of NERC or other Regional Entities. The Corporation may undertake such activities pursuant to a contract that is approved by the Executive Committee.

ARTICLE IV - BOARD OF DIRECTORS

4.1 **General Powers**. The affairs of the Corporation shall be managed by its Board of Directors except as otherwise provided in these Bylaws.

4.2 **Composition and Eligibility**. The Board of Directors shall be comprised of no fewer than three (3) Directors.

Each Director shall be the principal officer or other authorized employee from a Member Company or a company that controls, is controlled by, or is under common control with such Member Company (an "affiliated entity"). Each Member Company, together with any affiliated entities, may appoint one (1) Director to the Board of Directors. For clarification purposes only, each Member Company and all of such Member Company's affiliated entities (including any affiliated entities which may be a separate Member Company) shall have the right to appoint only one (1) Director to serve on behalf of such Member Company and all of such Member Company's affiliated entities. Each Director shall serve until otherwise replaced by the applicable Member Company, together with any affiliated entities. Each Member Company, together with any affiliated entities, may designate one (1) alternate Director, who shall be a principal officer or other authorized employee from the Director's Member Company or an affiliated entity, to serve in the place of the Member Company's Director at any meeting of the Board of Directors (an "Alternate Director"). Directors may not otherwise use proxy votes. Any vacancy occurring among the Directors or Alternate Directors shall be filled by the applicable Member Company, together with any affiliated entities.

4.3 **Customer Advisors; Board Advisors; and Other Participants.** The Board of Directors may, but shall not be required to, appoint one or more Customer Advisors to serve the Corporation. Each Customer Advisor shall be a person in the SERC Region who is (i) employed by an entity that receives service at retail and does not otherwise sell, purchase, or transmit power over the Bulk Power System or own, operate or maintain, control or operate facilities or systems that are part of the Bulk Power System; (ii) a state public utility commission representative; or (iii) any other customer advocate. The term of the Customer Advisor(s) shall be for a two (2) year period. The role of the Customer Advisor(s) is purely advisory and the Customer Advisor(s) shall have no authority whatsoever to bind the Corporation in any way.

The Board of Directors may, but shall not be required to, appoint one but no more than five Board Advisor(s) to serve the Corporation, the Board of Directors, the Executive Committee and the Officers of the Corporation. The Board Advisor(s) shall be either former Directors of the Corporation or former NERC Trustees. Appointments shall be made by the Board of Directors and those appointed shall serve for a term of one (1) year with no limits on eligibility for reappointment. The purpose of the Board Advisor(s) shall be to advise the Board of Directors, Executive Committee and Officers of the Corporation, as directed from time to time by the Board of Directors or the Executive Committee. The role of the Board Advisor(s) is purely advisory and the Board Advisor(s) shall have no authority whatsoever to bind the Corporation in any way.

The Chair of FERC and the chair or president of any State Utility Commission in a state in which electric service is provided by a Member Company of the Corporation shall be invited to designate an observer to attend meetings of the Board.

4.4 **Regular Meetings of the Board**. Unless otherwise determined by the Chair, a regular meeting of the Board of Directors shall be held without other notice than these Bylaws on the fourth Wednesday in the months of April and October in each year. Notwithstanding the foregoing, the Chair may elect to hold a regular semi-annual meeting of the Board of Directors on another date provided that the Board receives at least ten (10) days advance notice. If the day fixed for the meeting shall be a legal holiday in the State of North Carolina, the meeting shall be held on the next succeeding business day. The Board of Directors may designate any place as the place of meeting for any meeting. The Board of Directors may provide by resolution the time and place for the holding of additional regular meetings of the Board without other notice than the resolution. Directors or any committee designated by the Board of Directors may participate in such Board or committee meetings by means of a telephone conference, webcast or any other communication by means of which all persons participating in the meeting can hear each other at the same time, and participation by such means shall constitute presence in person at such meeting.

4.5 **Special Meetings of the Board**. Special meetings of the Board of Directors may be called at the request of the Chair, or by Directors holding twenty percent (20%) or more of the Individual Votes. The Chair may fix any place as the place for holding any special meeting of the Board.

4.6 **Notice of Special Meetings**. Notice of any special meeting of the Board of Directors shall be given at least two (2) days prior to the special meeting by written notice delivered personally, or sent by mail or electronic mail to each Director at the address as shown by the records of the Corporation. If mailed, such notice shall be deemed to be delivered when deposited in the United States mail in a sealed envelope so addressed, with postage prepaid. If sent by electronic mail, such notice shall be deemed to be delivered when sent via electronic mail. Any Director may waive notice of any meeting. The attendance of a Director at any meeting shall constitute a waiver of notice of such meeting, except where a Director attends a meeting for the express purpose of objecting to the transaction of any business because the meeting is not lawfully called or convened. Neither the business to be transacted at, nor the purpose of, any special meeting of the Board need be specified in the notice or waiver of notice of such meeting, unless specifically required by law or by these Bylaws.

4.7 **Election of Board Officers and Executive Committee**. Biennially, at the April meeting, the Board of Directors shall elect Board Officers from among the Directors for the positions of Chair, Vice Chair, and Secretary-Treasurer, each for a term of two (2) years beginning on July 1st after the election. No Director may serve in more than one (1) Board Officer position at the same time. The Chair shall conduct and preside at all meetings, be responsible for the preparation of the agenda, and carry out all other duties assigned by the Board of Directors. In the Chair's absence, the Vice Chair shall serve as acting Chair and shall preside at all meetings, be responsible for the preparation of the agenda, and carry out all other duties assigned by the Board of Directors. In the event that a Board Officer cannot complete his or her term, the Board of Directors may hold a

special election to elect a replacement Board Officer for the remainder of the unexpired term.

Initially, at the first April Board meeting following the integration of FRCC into SERC, the Board shall approve two groups (Group 1 and Group 2) of representatives to the Executive Committee which shall be nominated by the Sectors. Group 1 shall serve an initial three (3) year term and then for two (2) year terms thereafter, with terms beginning on July 1 after the approval; Group 2 shall serve an initial two (2) year term and then for two (2) year terms thereafter, with terms beginning on July 1 after the approval in alternating years from Group 1 terms. The initial allocation of Executive Committee representatives to Group 1 and Group 2 shall be recommended by the Nominating Committee and approved by the Chair, or in the absence of the Chair, by the Vice Chair. Each Sector may also elect alternates to the Executive Committee, which shall be elected on the same schedule as their representatives and, if a Sector has more than one (1) representative on the Executive Committee, such Sector shall designate the priority of succession by such alternates.

4.8 **Agenda**. As far in advance of each regular and special meeting as practical, an agenda shall be distributed to Directors and other participants.

4.9 **Compensation**. Directors shall not receive any compensation from the Corporation for their services to the Corporation.

4.10 **Duties**. The Board of Directors shall have the exclusive responsibility to:

(a) Authorize distributions;

(b) Recommend to members or approve dissolution, merger or the sale, pledge or transfer of substantially all of the Corporation's assets;

(c) Fill vacancies on any of the Board's committees;

(d) Adopt, amend, or repeal the Articles of Incorporation or Bylaws;

(e) Form or dissolve committees of the Board as it deems necessary to carry out the business of the Corporation; and

(f) Resolve any disputes regarding the Member Companies and the Corporation, if those issues cannot be resolved by the standing committees or subcommittees of the Corporation and are not otherwise subject to NERC's dispute provisions for non-compliance with Reliability Standards.

4.11 **Voting**. The intent of Sections 4.12 and 4.14 is to ensure that no two Sectors should be able to control any decision and that a single Sector should not be able

to veto any matter, respectively. In the event that either of the foregoing shall nevertheless occur, the Board shall promptly revise the provisions of these Bylaws so that no two Sectors shall be able to control any decision and no single Sector shall be able to veto any matter.

4.12 **Voting Definitions**.

(a) "Adjusted Weighted Vote" shall mean the number of votes of each Director determined in the manner set forth in Section 4.13 hereof.

(b) "Simple Majority" shall require the presence of a quorum and the (i) concurrence of Directors whose combined Individual Votes are greater than fifty percent (50%) of the total Individual Votes of all Directors present at the meeting and entitled to vote on the issue, (ii) concurrence of Directors whose combined Adjusted Weighted Votes are greater than fifty percent (50%) of the total Adjusted Weighted Vote of all Directors at the meeting and entitled to vote on the issue, and (iii) for at least one of the Individual Vote test or the Adjusted Weighted Vote test, on an individual Sector basis, the positive vote shall outweigh the negative vote for at least three Sectors.

(c) "Supermajority" shall require the presence of a quorum and the (i) concurrence of Directors whose combined Individual Votes equal or exceed two-thirds (2/3) of the total Individual Votes of all Directors present at the meeting and entitled to vote on the issue, (ii) concurrence of Directors whose combined Adjusted Weighted Votes are greater than two-thirds (2/3) of the total Adjusted Weighted Vote of all Directors present at the meeting and entitled to vote on the issue, and (iii) for at least one of the Individual Vote test or the Adjusted Weighted Vote test, on an individual Sector basis, the positive vote shall outweigh the negative vote for at least three Sectors.

(d) "Individual Vote" shall mean a single vote accorded to each Director.

(e) "Given Year" shall mean the applicable fiscal year for which the Adjusted Weighted Votes are calculated.

(f) "Reporting Year" shall mean the fiscal year immediately preceding the Given Year.

(g) "Previous Year" shall mean the fiscal year immediately preceding the Reporting Year.

4.13 **Determination of Adjusted Weighted Vote**. The Directors' Adjusted Weighted Votes for a Given Year shall be determined by the following formula:

V = 10(1/N) + 30(B/C) + 30(D/E) + 30(F/G)

V = % of Adjusted Weighted Vote

N = total number of Member Companies

B = Member Company's Previous Year internal peak demand

C = total of factor B for all Member Companies

D = Member Company's owned generating capacity as of January 1 of the Reporting Year

E = total of factor D for all Member Companies

F = Member Company's sum of circuit miles of transmission times the respective operating voltage for facilities of 69 kV and above as of December 31 of the Previous Year

G = total of factor F for all Member Companies

4.14 **Voting; Manner of Acting; Voting Rights; Quorum**.

(a) Except as otherwise provided in these Bylaws, all actions by the Board of Directors require approval by a Simple Majority vote.

(b) A motion which requires a vote shall be deemed to have passed by the requisite vote if it passes either:

(i) the Individual Vote test; or
(ii) the Adjusted Weighted Vote test;

and, for purposes of the failed test (any test that is not satisfied), on an individual Sector basis, the positive votes outweigh the negative votes in every Sector but one.

(c) Directors holding two-thirds (2/3) of the Individual Votes shall constitute a quorum for action by the Board. If Directors holding less than two-thirds (2/3) of the Individual Votes are present at the meeting, a majority of the Directors present may adjourn the meeting from time to time without further notice.

4.15 **Action without a meeting**. Any action required by law to be taken at a meeting of Directors, or any action which may be taken at a meeting of Directors, may be taken without a meeting if all of the Directors consent in writing to the action so taken.

The action shall be evidenced by one or more written consents describing the action taken, signed by each Director, and included in the minutes or filed with the corporate records reflecting the action taken. Action taken under this section is effective when the last Director signs the consent unless the consent specifies a different effective date. A consent signed under this section has the effect of a meeting vote. A Director's consent to action taken without a meeting may be in electronic form and delivered by electronic means.

ARTICLE V - CORPORATE OFFICERS

5.1 **Corporate Officers**. The Board of Directors shall appoint a President/Chief Executive Officer, one or more Vice Presidents, a Secretary, and a Treasurer of the Corporation. Two (2) or more of such offices may be held by the same person, except for the offices of President/Chief Executive Officer and Secretary. The Board of Directors may appoint such other officers and assistant officers as it deems necessary. The Board Officers shall determine the compensation and benefits for all Corporate Officers.

5.2 **President/Chief Executive Officer**. The President shall be the Chief Executive Officer of the Corporation and shall manage the operations of the Corporation to the end that its purposes shall be accomplished. The President shall:

(a) Promote the mission of the Corporation and implement the goals and objectives of the Corporation;

(b) Report to the Board of Directors and carry out the policies and procedures set by the Board of Directors;

(c) Represent SERC at all NERC Stakeholder and Board of Trustees, meetings, as appropriate;

(d) Attend all Board of Directors meetings and serve as ex-officio non-voting member of (i) the Board of Directors, (ii) the Executive Committee, and (iii) all other Board committees;

(e) Coordinate subregional activities and interregional affairs, to include data collection;

(f) Oversee the business affairs of the Corporation, including the Corporation staff, and enact such policies and procedures for staff as are needed to implement the goals and objectives of the Corporation; and

(g) Provide other assistance to the Corporation and NERC, as appropriate.

5.3 **Vice President.** The Corporation may have one or more Vice Presidents. A Vice President of the Corporation shall perform such duties and exercise such powers as may be assigned to him or her from time to time by the Board of Directors, the Executive Committee, or the President. In the absence of the President, or in the case of the President's inability to act (because of death, resignation, removal, disqualification, or otherwise), a Vice President of the Corporation may be appointed to perform the duties and exercise the powers of the President, subject to the control of the Board of Directors and the Executive Committee.

5.4 **Secretary.** The Secretary of the Corporation shall be custodian of and shall maintain the corporate books, records and the minutes of the meetings of the Board of Directors and other Corporation-related meetings and shall assure that all required notices are duly given in accordance with these Bylaws, the Articles of Incorporation or as otherwise may be required by law. The Secretary of the Corporation shall also be the custodian of the seal of the Corporation. The Secretary of the Corporation shall, in general, perform all duties incident to the office of Secretary of the Corporation and such other duties as may, from time to time, be assigned to him or her by the Board of Directors, the Executive Committee, or the President.

5.5 **Treasurer.** The Treasurer of the Corporation shall have charge and custody of, and be responsible for, all funds and securities of the Corporation and deposit all such funds in the name of the Corporation in such banks, trust companies, or other depositaries as shall be selected in accordance with the provisions of these Bylaws. The Treasurer of the Corporation shall, in general, perform all of the duties incident to the office of Treasurer of the Corporation and such other duties as from time to time may be assigned to him or her by the Board of Directors, the Executive Committee, or the President.

ARTICLE VI - EXECUTIVE COMMITTEE

6.1 **Executive Committee Representatives**. The Executive Committee shall be comprised of fifteen (15) Sector representatives from the Board of Directors, consisting of:

(a) The Investor-Owned Utility Sector shall have four (4) representatives;

(b) The Federal/State Sector shall have two (2) representatives;

(c) The Cooperative Sector shall have three (3) representatives;

(d) The Municipal Sector shall have three (3) representatives;

(e) The Marketer Sector shall have one (1) representative;

(f) The Merchant Electricity Generator Sector shall have one (1) representative; and

(g) The ISO-RTO Sector shall have one (1) representative.

It is the desire of the Board of Directors that the Cooperative and Municipal sectors have representation from both transmission dependent and transmission owning Members.

Each Sector shall be responsible for nominating their representative(s) and alternates from among the Directors. The Chair of the Board shall serve as Chair of the Executive Committee and shall conduct all meetings and shall be responsible for the preparation of the agenda. In the event that a representative on the Executive Committee is unable to complete a term, the Sector's alternate shall replace such representative.

6.2 **Ex Officio Representatives**. The Chair, Vice Chair, and Secretary-Treasurer of the Board of Directors shall also be ex officio representatives on the Executive Committee, but shall not have voting rights unless such Board Officer is also elected by a Sector to the Executive Committee pursuant to Section 6.1 above.

6.3 **Authority of Executive Committee**. Except as limited by Section 55A-8-25 of the North Carolina Nonprofit Corporation Act and Section 4.10 of these Bylaws, the Executive Committee is empowered to make all such decisions and take such actions as are deemed to be necessary for the operation of the Corporation.

6.4 **Action.** Each voting representative on the Executive Committee shall have one vote. The presence of three-quarters (3/4) of the voting representatives on the Executive Committee shall constitute a quorum. The positive vote of two-thirds (2/3) of Executive Committee voting representatives present and voting is necessary to pass a particular action.

ARTICLE VII - OTHER COMMITTEES

7.1 **Designation by Board**. The Board of Directors, by resolution adopted by a Simple Majority vote, may designate Board committees and standing committees, as shall be necessary to address the purposes of the Corporation. Each Board committee shall have at least two Directors among its members.

7.2 **Rules for Governance**. Each committee shall adopt rules for its own governance that are not inconsistent with these Bylaws, rules adopted by the Board of Directors, applicable NERC or FERC rules or regulations, or applicable state or federal laws. Each committee shall maintain its rules for governance in a written scope document that is approved by the Board of Directors.

7.3 **Ad-Hoc Support Committees**. The Board or its committees may, from time to time, appoint ad-hoc committees to research and/or advise it on compliance or technical issues or matters, among other things. Such ad-hoc committees may be formed on an as-needed basis and may vary in makeup depending on the needs of the Board or its committees.

ARTICLE VIII - MISCELLANEOUS

8.1 **Conflicts of Interest.** All Directors, Alternate Directors, Customer Advisors, Board Advisors, and Board committee representatives shall comply with the Corporation's Standards of Conduct policy that prohibits conflicts of interest, as such conflicts could cast doubt on the ability of such persons to act with total objectivity with regard to the overall interests of the Corporation.

8.2 **Contracts**. The Board of Directors may authorize any officer or agent of the Corporation, in addition to the officers so authorized by these Bylaws, to enter into any contract or execute and deliver any instrument in the name of and on behalf of the Corporation, and such authority may be general or confined to specific instances.

8.3 **Checks, Drafts, etc**. All checks, drafts, or orders for the payment of money, notes or other evidences of indebtedness issued in the name of the Corporation, shall be signed by an authorized officer or agent of the Corporation and in such manner as shall from time to time be determined by resolution of the Executive Committee. In the absence of such determination by the Executive Committee, such instruments shall be signed by the Board's Secretary-Treasurer, the Corporation's President, or the Corporation's Finance Director, as stipulated by the Executive Committee. The Corporation's Finance Director may arrange audits of financial records, sign appropriate documents, and perform such duties normally performed by the Board's Secretary-Treasurer, except duties assigned to the Corporation's President.

8.4 **Deposits**. All funds of the Corporation shall be deposited from time to time to the credit of the Corporation in such banks, trust companies, or other depositories as the Corporation's President may select.

8.5 **Books and Records**. The Corporation shall keep correct and complete books and records of account and shall also keep minutes of the proceedings of the Board of Directors and committees having any of the authority of the Board of Directors, and

shall keep at its registered or principal office a record giving the names and addresses of the Directors. All books and records of the Corporation may be inspected by any Director, or agent or attorney representing any Director, for any proper purpose at any reasonable time.

8.6 **Seal**. The corporate seal shall be in circular form and shall have inscribed thereon the name of the Corporation, the words "Corporate Seal", and such other word or words, if any, as may be determined by the Board of Directors to be inscribed thereon.

8.7 **Fiscal Year.** The fiscal year of the Corporation shall begin on the first day of January and end on the last day of December in each year.

ARTICLE IX - EXPENSES

9.1 **Allocation of Specific Expenses.** The expenses of Directors and Board Officers shall be borne by that person's regular employer.

9.2 **Statutory Functions.** The Corporation anticipates that as a general rule all of its expenses shall be incurred in the furtherance of statutory activities pursuant to Section 215 of the Federal Power Act, and that all such expenses shall be funded by NERC, subject to FERC approval.

9.3 **Non-Statutory Functions.** Notwithstanding Section 9.2, the Board of Directors may from time to time authorize the Corporation to participate in non-statutory activities (i.e., activities not described in Section 215 of the Federal Power Act). In the event that the Corporation proposes to engage in non-statutory activities, such activities shall be identified in the Corporation's annual business plan that is submitted to NERC and, if approved by NERC, shall be submitted to FERC for approval in advance of engaging in such non-statutory activities. The expenses incurred by the Corporation for any such approved non-statutory activities shall be allocated by the Board of Directors to the beneficiaries of such activities on a basis proposed in the business plan submitted for NERC and FERC approval.

ARTICLE X - DISPUTE RESOLUTION PROCESS

10.1 **Dispute Resolution.** All disputes regarding non-compliance with Reliability Standards shall be handled in accordance with the NERC Rules of Procedure. The organizational units of the Corporation shall deal with all other disputes within the framework of their respective organizations. For such other disputes, Member Companies of the Corporation are encouraged to utilize the appropriate Dispute

Resolution Process within the Corporation prior to seeking resolution at NERC, FERC, or with legal counsel.

ARTICLE XI - DISSOLUTION

11.1 **Dissolution**. The Corporation may be voluntarily dissolved upon unanimous consent of the Board of Directors, and in accordance with Section 55A-14-02 of the North Carolina Nonprofit Corporation Act, as amended from time to time.

11.2 **Distribution of Assets**. Upon dissolution of the Corporation as provided in Section 11.1, the residual assets, after payment of all just obligations, shall be distributed exclusively to organizations which are exempt from federal income tax under Section 501(c)(6) of the Internal Revenue Code of 1986, or corresponding provisions of any subsequent federal tax laws, as the Board of Directors shall determine.

ARTICLE XII - WAIVER OF NOTICE

12.1 **Waiver.** Whenever any notice is required to be given under the provisions of the North Carolina Nonprofit Corporation Act or under the provisions of the articles of incorporation or the Bylaws of the Corporation, a waiver thereof in writing signed by the person or persons entitled to such notice, whether before or after the time stated therein, shall be deemed equivalent to the giving of such notice.

ARTICLE XIII - INDEMNIFICATION

13.1 **Indemnification of Directors, Alternate Directors, Customer Advisors, Board Advisors, Committee Members, Officers, Employees and Agents**. Every person who is, or has served as, a Director, Alternate Director, Customer Advisor, Board Advisor, committee member, Officer, employee, or agent of the Corporation shall be indemnified by the Corporation in the manner and to the extent authorized by the North Carolina Nonprofit Corporation Act. The foregoing rights of indemnification shall be without prejudice to any other rights to which any such Director, Alternate Director, Customer Advisor, Board Advisor, committee member, Officer, employee, or agent may be entitled as a matter of law.

ARTICLE XIV - AMENDMENT OF THE BYLAWS AND ARTICLES OF INCORPORATION

14.1 **Amendment of the Bylaws and Articles of Incorporation**. After a request by twenty percent (20%) of the Board of Directors or an affirmative vote of the Executive Committee, a proposal to amend the Bylaws or the Articles of Incorporation shall be put before the Board of Directors at any regular or special meeting for a vote. Copies of the proposed amendments shall be distributed to the Board of Directors at least thirty (30) days before the meeting at which they are to be considered. An amendment to the Bylaws or the Articles of Incorporation shall be adopted after being approved by a Supermajority vote of the Board of Directors, provided that a quorum is present.

AMENDED AND RESTATED

BYLAWS

OF

SERC RELIABILITY CORPORATION

A North Carolina Nonprofit Corporation

Approved by the SERC Board of Directors on ~~April 22, 2015~~ October 24, 2018

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AMENDED AND RESTATED

BYLAWS

OF

SERC RELIABILITY CORPORATION
[Hereinafter referred to as the "Corporation"]

A North Carolina Nonprofit Corporation

ARTICLE I - OFFICES

1.1 **Principal Office**. The principal office of the Corporation shall be located in the City of Charlotte, Mecklenburg County, North Carolina. The Board of Directors may by resolution change the location of this office from time to time.

1.2 **Other Offices**. The Corporation may have other offices at such place or places as the Board of Directors may from time to time appoint or the business of the Corporation may require.

ARTICLE II - MEMBERSHIP

2.1 **General**. The Corporation shall be a membership corporation. Entities that meet the eligibility requirements and apply for membership in the Corporation shall hereinafter be referred to individually as a "Member Company" and collectively as "Member Companies".

2.2 **Eligibility**. Membership in the Corporation is voluntary and is open to any entity in the SERC Region (defined in Section 3.2 below) that is a user, owner or operator of the Bulk Power System, has a material interest in the Bulk Power System in the SERC Region, satisfies the criteria for membership specified in this Section 2.2, qualifies for one or more of the Sectors identified in Section 2.4, and is subject to the jurisdiction of the Federal Energy Regulatory Commission. Membership in the Corporation is predicated on mandatory acceptance of the responsibility to promote, support, and comply with Reliability Standards of the Corporation and the North American Electric Reliability Corporation ("NERC"), and to assist the Corporation in its compliance with the terms and provisions of a Delegation Agreement (a "Delegation Agreement") with NERC, by which NERC delegates authority to propose and enforce Reliability Standards, pursuant to 16 U.S.C. § 824o or the corresponding provisions of any subsequent U.S. Code revisions.

For purposes of these Bylaws, the terms “Bulk Power System”, “Reliability Standards” and “Regional Entity” shall be as defined in 16 U.S.C. § 824o or the corresponding provisions of any subsequent U.S. Code revisions.

2.3 **Termination**. A Member Company may terminate its membership in the Corporation by giving the Board of Directors at least thirty (30) days written notice of its intent to terminate such membership (such Member Companies shall hereinafter be referred to as "Terminated Member Companies"). Terminated Member Companies shall nevertheless continue to be liable for any and all obligations incurred prior to the end of the calendar year in which such notice is given, including, but not limited to, the obligation to pay a pro rata share of any Corporation expense. In addition to termination of membership by the Member Company, the Board of Directors, following notice to the Member Company, may terminate the membership of a Member Company if in the judgment of the Board of Directors that Member Company has violated its obligations and responsibilities to the Corporation. The termination of the membership of a Member Company by the Board of Directors shall require a Supermajority vote, as defined in these Bylaws.

2.4 **Sectors.** Each Member Company shall be classified by the Executive Committee in one of the following seven (7) Sectors (each a “Sector”, and collectively, the “Sectors”):

(a) Investor-Owned Utility Sector – This Sector includes any investor-owned entity with substantial business interest in ownership and/or operation in any of the asset categories of generation, transmission or distribution.

(b) Federal/State Sector – This Sector includes any U.S. federal entity that owns and/or operates electric facilities and/or provides balancing authority services, in any of the asset categories of generation, transmission, or distribution; or any entity that is owned by or subject to the governmental authority of a state and that is engaged in the generation, delivery, and/or sale of electric power to end-use customers primarily within the political boundaries of the state.

(c) Cooperative Sector – This Sector includes any non-governmental entity that is incorporated under the laws of the state in which it operates, is owned by and provides electric service to end-use customers at cost, and is governed by a board of directors that is elected by the membership of the entity; and any non-governmental entity owned by and which provides generation and/or transmission service to such entities.

(d) Municipal Sector – This Sector includes any entity owned by or subject to the governmental authority of a municipality, that is

engaged in the generation, delivery, and/or sale of electric power to end-use customers primarily within the political boundaries of the municipality; and any entity, whose members are municipalities, formed under state law for the purpose of generating or purchasing electricity for sale at wholesale to their members.

(e) Marketer Sector– This Sector includes any entity that is engaged in the activity of buying and selling of wholesale electric power in the SERC Region on a physical or financial basis.

(f) Merchant Electricity Generator Sector – This Sector includes any entity that owns or operates an electricity generating facility or provides balancing authority services for such entities. This includes, but is not limited to, small power producers and all other non-utility producers such as exempt wholesale generators who sell electricity at wholesale.

(g) ISO-RTO Sector – This Sector includes any entity that operates a FERC approved ISO or RTO.

The Executive Committee's classification of a Member Company in a particular Sector may only be changed by the Executive Committee.

2.5 **Transfer of Membership.** A Member Company may not give or otherwise transfer its membership, except to a successor that becomes a Member Company in accordance with the terms and conditions of these Bylaws, and provided that the successor continues to meet its predecessor's obligations.

2.6 **Powers.** Notwithstanding any other provisions of these Bylaws, except for the appointment of Directors as provided in Section 4.2 below, Member Companies shall be non-voting members and shall have no power or authority or right to vote with respect to the actions of the Corporation, specifically including, but not limited to, the dissolution or merger of the Corporation.

ARTICLE III - PURPOSES

3.1 **General Purposes.** The purpose of the Corporation is to promote effective and efficient administration of Bulk Power System reliability in the SERC Region, as defined in Section 3.2. In pursuit of this goal, the Corporation shall:

(a) enter into a Delegation Agreement to serve as a Regional Entity pursuant to 16 U.S.C. § 824o or the corresponding provisions of any subsequent U.S. Code revisions;

(b) promote the development of reliability and adequacy arrangements among the systems in the SERC Region;

(c) participate in the establishment of Reliability Standards;

(d) participate in the measurement of performance relative to these Reliability Standards;

(e) promote conformance to and compliance with these Reliability Standards;

(f) develop and exchange information with respect to planning and operating matters relating to the reliability and adequacy of the Bulk Power System;

(g) review as necessary activities in the SERC Region on reliability and adequacy in order to meet Reliability Standards;

(h) provide a mechanism to resolve disputes on reliability issues in a manner that meets the needs of the parties and the SERC Region; and

(i) provide information with respect to matters considered by the Corporation, where appropriate, to the Federal Energy Regulatory Commission ("FERC") and to other federal and state agencies concerned with reliability and adequacy.

3.2 **Geographic Area.** The Corporation accomplishes its purposes in a geographic area (the "SERC Region") that is defined in Exhibit A of the Amended and Restated Delegation Agreement Between North American Electric Reliability Corporation and SERC Reliability Corporation.

3.3 **Other Statutory Functions.** The Corporation may also perform statutory functions outside of the SERC Region, on behalf of NERC or other Regional Entities. The Corporation may undertake such activities pursuant to a contract that is approved by the Executive Committee.

ARTICLE IV - BOARD OF DIRECTORS

4.1 **General Powers**. The affairs of the Corporation shall be managed by its Board of Directors except as otherwise provided in these Bylaws.

4.2 **Composition and Eligibility**. The Board of Directors shall be comprised of no fewer than three (3) Directors.

Each Director shall be the principal officer or other authorized employee from a Member Company or a company that controls, is controlled by, or is under common control with such Member Company (an "affiliated entity"). Each Member Company, together with any affiliated entities, may appoint one (1) Director to the Board of Directors. For clarification purposes only, each Member Company and all of such Member Company's affiliated entities (including any affiliated entities which may be a separate Member Company) shall have the right to appoint only one (1) Director to serve on behalf of such Member Company and all of such Member Company's affiliated entities. Each Director shall serve until otherwise replaced by the applicable Member Company, together with any affiliated entities. Each Member Company, together with any affiliated entities, may designate one (1) alternate Director, who shall be a principal officer or other authorized employee from the Director's Member Company or an affiliated entity, to serve in the place of the Member Company's Director at any meeting of the Board of Directors (an "Alternate Director"). Directors may not otherwise use proxy votes. Any vacancy occurring among the Directors or Alternate Directors shall be filled by the applicable Member Company, together with any affiliated entities.

4.3 **Customer Advisors; Board Advisors; and Other Participants.** The Board of Directors may, but shall not be required to, appoint one or more Customer Advisors to serve the Corporation. Each Customer Advisor shall be a person in the SERC Region who is (i) employed by an entity that receives service at retail and does not otherwise sell, purchase, or transmit power over the Bulk Power System or own, operate or maintain, control or operate facilities or systems that are part of the Bulk Power System; (ii) a state public utility commission representative; or (iii) any other customer advocate. The term of the Customer Advisor(s) shall be for a two (2) year period. The role of the Customer Advisor(s) is purely advisory and the Customer Advisor(s) shall have no authority whatsoever to bind the Corporation in any way.

The Board of Directors may, but shall not be required to, appoint one but no more than five Board Advisor(s) to serve the Corporation, the Board of Directors, the Executive Committee and the Officers of the Corporation. The Board Advisor(s) shall be either former Directors of the Corporation or former NERC Trustees. Appointments shall be made by the Board of Directors and those appointed shall serve for a term of one (1) year with no limits on eligibility for reappointment. The purpose of the Board Advisor(s) shall be to advise the Board of Directors, Executive Committee and Officers of the Corporation, as directed from time to time by the Board of Directors or the Executive Committee. The role of the Board Advisor(s) is purely advisory and the Board Advisor(s) shall have no authority whatsoever to bind the Corporation in any way.

The Chair of FERC and the chair or president of any State Utility Commission in a state in which electric service is provided by a Member Company of the Corporation shall be invited to designate an observer to attend meetings of the Board.

4.4 **Regular Meetings of the Board**. Unless otherwise determined by the Chair, a regular meeting of the Board of Directors shall be held without other notice than these Bylaws on the fourth Wednesday in the months of April and October in each year. Notwithstanding the foregoing, the Chair may elect to hold a regular semi-annual meeting of the Board of Directors on another date provided that the Board receives at least ten (10) days advance notice. If the day fixed for the meeting shall be a legal holiday in the State of North Carolina, the meeting shall be held on the next succeeding business day. The Board of Directors may designate any place as the place of meeting for any meeting. The Board of Directors may provide by resolution the time and place for the holding of additional regular meetings of the Board without other notice than the resolution. Directors or any committee designated by the Board of Directors may participate in such Board or committee meetings by means of a telephone conference, webcast or any other communication by means of which all persons participating in the meeting can hear each other at the same time, and participation by such means shall constitute presence in person at such meeting.

4.5 **Special Meetings of the Board**. Special meetings of the Board of Directors may be called at the request of the Chair, or by Directors holding twenty percent (20%) or more of the Individual Votes. The Chair may fix any place as the place for holding any special meeting of the Board.

4.6 **Notice of Special Meetings**. Notice of any special meeting of the Board of Directors shall be given at least two (2) days prior to the special meeting by written notice delivered personally, or sent by mail or electronic mail to each Director at the address as shown by the records of the Corporation. If mailed, such notice shall be deemed to be delivered when deposited in the United States mail in a sealed envelope so addressed, with postage prepaid. If sent by electronic mail, such notice shall be deemed to be delivered when sent via electronic mail. Any Director may waive notice of any meeting. The attendance of a Director at any meeting shall constitute a waiver of notice of such meeting, except where a Director attends a meeting for the express purpose of objecting to the transaction of any business because the meeting is not lawfully called or convened. Neither the business to be transacted at, nor the purpose of, any special meeting of the Board need be specified in the notice or waiver of notice of such meeting, unless specifically required by law or by these Bylaws.

4.7 **Election of Board Officers and Executive Committee**. Biennially, at the April meeting, the Board of Directors shall elect Board Officers from among the Directors for the positions of Chair, Vice Chair, and Secretary-Treasurer, each for a term of two (2) years beginning on July 1st after the election. No Director may serve in more than one (1) Board Officer position at the same time. The Chair shall conduct and preside at all meetings, be responsible for the preparation of the agenda, and carry out all other duties assigned by the Board of Directors. In the Chair's absence, the Vice Chair shall serve as acting Chair and shall preside at all meetings, be responsible for the preparation of the agenda, and carry out all other duties assigned by the Board of Directors. In the event that a Board Officer cannot complete his or her term, the Board of Directors may hold a

special election to elect a replacement Board Officer for the remainder of the unexpired term.

~~At the same time~~Initially, at the first April Board meeting following the integration of FRCC into SERC, the Board shall approve two groups (Group 1 and Group 2) of representatives to the Executive Committee which shall be nominated by the Sectors. Group 1 shall serve an initial three (3) year term and then for two (2) year terms thereafter, with terms beginning on July 1 after the approval; Group 2 shall serve an initial two (2) year term and then for two (2) year terms thereafter, with terms beginning on July 1 after the approval in alternating years from Group 1 terms. The initial allocation of Executive Committee representatives to Group 1 and Group 2 shall be recommended by the Nominating Committee and approved by the Chair, or in the absence of the Chair, by the Vice Chair. ~~to serve for a period of two (2) years beginning July 1st, after the approval.~~ Each Sector may also elect alternates to the Executive Committee, which shall be elected on the same schedule as their representatives and, if a Sector has more than one (1) representative on the Executive Committee, such Sector shall designate the priority of succession by such alternates.

4.8 **Agenda**. As far in advance of each regular and special meeting as practical, an agenda shall be distributed to Directors and other participants.

4.9 **Compensation**. Directors shall not receive any compensation from the Corporation for their services to the Corporation.

4.10 **Duties**. The Board of Directors shall have the exclusive responsibility to:

(a) Authorize distributions;

(b) Recommend to members or approve dissolution, merger or the sale, pledge or transfer of substantially all of the Corporation's assets;

(c) Fill vacancies on any of the Board's committees;

(d) Adopt, amend, or repeal the Articles of Incorporation or Bylaws;

(e) Form or dissolve committees of the Board as it deems necessary to carry out the business of the Corporation; and

(f) Resolve any disputes regarding the Member Companies and the Corporation, if those issues cannot be resolved by the standing committees or subcommittees of the Corporation and are not otherwise subject to NERC's dispute provisions for non-compliance with Reliability Standards.

4.11 **Voting**. The intent of Sections 4.12 and 4.14 is to ensure that no two Sectors should be able to control any decision and that a single Sector should not be able to veto any matter, respectively. In the event that either of the foregoing shall nevertheless occur, the Board shall promptly revise the provisions of these Bylaws so that no two Sectors shall be able to control any decision and no single Sector shall be able to veto any matter.

4.12 **Voting Definitions**.

(a) "Adjusted Weighted Vote" shall mean the number of votes of each Director determined in the manner set forth in Section 4.13 hereof.

(b) "Simple Majority" shall require the presence of a quorum and the (i) concurrence of Directors whose combined Individual Votes are greater than fifty percent (50%) of the total Individual Votes of all Directors present at the meeting and entitled to vote on the issue, (ii) concurrence of Directors whose combined Adjusted Weighted Votes are greater than fifty percent (50%) of the total Adjusted Weighted Vote of all Directors at the meeting and entitled to vote on the issue, and (iii) for at least one of the Individual Vote test or the Adjusted Weighted Vote test, on an individual Sector basis, the positive vote shall outweigh the negative vote for at least three Sectors.

(c) "Supermajority" shall require the presence of a quorum and the (i) concurrence of Directors whose combined Individual Votes equal or exceed two-thirds (2/3) of the total Individual Votes of all Directors present at the meeting and entitled to vote on the issue, (ii) concurrence of Directors whose combined Adjusted Weighted Votes are greater than two-thirds (2/3) of the total Adjusted Weighted Vote of all Directors present at the meeting and entitled to vote on the issue, and (iii) for at least one of the Individual Vote test or the Adjusted Weighted Vote test, on an individual Sector basis, the positive vote shall outweigh the negative vote for at least three Sectors.

(d) "Individual Vote" shall mean a single vote accorded to each Director.

(e) "Given Year" shall mean the applicable fiscal year for which the Adjusted Weighted Votes are calculated.

(f) "Reporting Year" shall mean the fiscal year immediately preceding the Given Year.

(g) "Previous Year" shall mean the fiscal year immediately preceding the Reporting Year.

4.13 **Determination of Adjusted Weighted Vote**. The Directors' Adjusted Weighted Votes for a Given Year shall be determined by the following formula:

V = 10(1/N) + 30(B/C) + 30(D/E) + 30(F/G)

V = % of Adjusted Weighted Vote

N = total number of Member Companies

B = Member Company's Previous Year internal peak demand

C = total of factor B for all Member Companies

D = Member Company's owned generating capacity as of January 1 of the Reporting Year

E = total of factor D for all Member Companies

F = Member Company's sum of circuit miles of transmission times the respective operating voltage for facilities of 69 kV and above as of December 31 of the Previous Year

G = total of factor F for all Member Companies

4.14 **Voting; Manner of Acting; Voting Rights; Quorum**.

(a) Except as otherwise provided in these Bylaws, all actions by the Board of Directors require approval by a Simple Majority vote.

(b) A motion which requires a vote shall be deemed to have passed by the requisite vote if it passes either:

(i) the Individual Vote test; or
(ii) the Adjusted Weighted Vote test;

and, for purposes of the failed test (any test that is not satisfied), on an individual Sector basis, the positive votes outweigh the negative votes in every Sector but one.

(c) Directors holding two-thirds (2/3) of the Individual Votes shall constitute a quorum for action by the Board. If Directors holding less than two-thirds (2/3) of the Individual Votes are present at the meeting, a majority of the Directors present may adjourn the meeting from time to time without further notice.

4.15 **Action without a meeting**. Any action required by law to be taken at a meeting of Directors, or any action which may be taken at a meeting of Directors, may be taken without a meeting if all of the Directors consent in writing to the action so taken. The action shall be evidenced by one or more written consents describing the action taken, signed by each Director, and included in the minutes or filed with the corporate records reflecting the action taken. Action taken under this section is effective when the last Director signs the consent unless the consent specifies a different effective date. A consent signed under this section has the effect of a meeting vote. A Director's consent to action taken without a meeting may be in electronic form and delivered by electronic means.

ARTICLE V - CORPORATE OFFICERS

5.1 **Corporate Officers**. The Board of Directors shall appoint a President/Chief Executive Officer, one or more Vice Presidents, a Secretary, and a Treasurer of the Corporation. Two (2) or more of such offices may be held by the same person, except for the offices of President/Chief Executive Officer and Secretary. The Board of Directors may appoint such other officers and assistant officers as it deems necessary. The Board Officers shall determine the compensation and benefits for all Corporate Officers.

5.2 **President/Chief Executive Officer**. The President shall be the Chief Executive Officer of the Corporation and shall manage the operations of the Corporation to the end that its purposes shall be accomplished. The President shall:

(a) Promote the mission of the Corporation and implement the goals and objectives of the Corporation;

(b) Report to the Board of Directors and carry out the policies and procedures set by the Board of Directors;

(c) Represent SERC at all NERC Stakeholder and Board of Trustees, meetings, as appropriate;

(d) Attend all Board of Directors meetings and serve as ex-officio non-voting member of (i) the Board of Directors, (ii) the Executive Committee, and (iii) all other Board committees;

(e) Coordinate subregional activities and interregional affairs, to include data collection;

(f) Oversee the business affairs of the Corporation, including the Corporation staff, and enact such policies and procedures for staff

as are needed to implement the goals and objectives of the Corporation; and

(g) Provide other assistance to the Corporation and NERC, as appropriate.

5.3 **Vice President.** The Corporation may have one or more Vice Presidents. A Vice President of the Corporation shall perform such duties and exercise such powers as may be assigned to him or her from time to time by the Board of Directors, the Executive Committee, or the President. In the absence of the President, or in the case of the President's inability to act (because of death, resignation, removal, disqualification, or otherwise), a Vice President of the Corporation may be appointed to perform the duties and exercise the powers of the President, subject to the control of the Board of Directors and the Executive Committee.

5.4 **Secretary.** The Secretary of the Corporation shall be custodian of and shall maintain the corporate books, records and the minutes of the meetings of the Board of Directors and other Corporation-related meetings and shall assure that all required notices are duly given in accordance with these Bylaws, the Articles of Incorporation or as otherwise may be required by law. The Secretary of the Corporation shall also be the custodian of the seal of the Corporation. The Secretary of the Corporation shall, in general, perform all duties incident to the office of Secretary of the Corporation and such other duties as may, from time to time, be assigned to him or her by the Board of Directors, the Executive Committee, or the President.

5.5 **Treasurer.** The Treasurer of the Corporation shall have charge and custody of, and be responsible for, all funds and securities of the Corporation and deposit all such funds in the name of the Corporation in such banks, trust companies, or other depositaries as shall be selected in accordance with the provisions of these Bylaws. The Treasurer of the Corporation shall, in general, perform all of the duties incident to the office of Treasurer of the Corporation and such other duties as from time to time may be assigned to him or her by the Board of Directors, the Executive Committee, or the President.

ARTICLE VI - EXECUTIVE COMMITTEE

6.1 **Executive Committee Representatives**. The Executive Committee shall be comprised of ~~twelve~~ fifteen (~~12~~15) Sector representatives from the Board of Directors, consisting of:

(a) The Investor-Owned Utility Sector shall have ~~three~~ four (~~3~~4) representatives;

(b) The Federal/State Sector shall have two (2) representatives;

(c) The Cooperative Sector shall have ~~two~~ three (~~2~~3) representatives;

(d) The Municipal Sector shall have ~~two~~ three (~~2~~3) representatives;

(e) The Marketer Sector shall have one (1) representative;

(f) The Merchant Electricity Generator Sector shall have one (1) representative; and

(g) The ISO-RTO Sector shall have one (1) representative.

It is the desire of the Board of Directors that the Cooperative and Municipal sectors have representation from both transmission dependent and transmission owning Members.

Each Sector shall be responsible for nominating their representative(s) and alternates from among the Directors. The Chair of the Board shall serve as Chair of the Executive Committee and shall conduct all meetings and shall be responsible for the preparation of the agenda. In the event that a representative on the Executive Committee is unable to complete a term, the Sector's alternate shall replace such representative.

6.2 **Ex Officio Representatives**. The Chair, Vice Chair, and Secretary-Treasurer of the Board of Directors shall also be ex officio representatives on the Executive Committee, but shall not have voting rights unless such Board Officer is also elected by a Sector to the Executive Committee pursuant to Section 6.1 above.

6.3 **Authority of Executive Committee**. Except as limited by Section 55A-8-25 of the North Carolina Nonprofit Corporation Act and Section 4.10 of these Bylaws, the Executive Committee is empowered to make all such decisions and take such actions as are deemed to be necessary for the operation of the Corporation.

6.4 **Action.** Each voting representative on the Executive Committee shall have one vote. The presence of three-quarters (3/4) of the voting representatives on the Executive Committee shall constitute a quorum. The positive vote of two-thirds (2/3) of Executive Committee voting representatives present and voting is necessary to pass a particular action.

ARTICLE VII - OTHER COMMITTEES

7.1 **Designation by Board**. The Board of Directors, by resolution adopted by a Simple Majority vote, may designate Board committees and standing committees, as

shall be necessary to address the purposes of the Corporation. Each Board committee shall have at least two Directors among its members.

7.2 **Rules for Governance**. Each committee shall adopt rules for its own governance that are not inconsistent with these Bylaws, rules adopted by the Board of Directors, applicable NERC or FERC rules or regulations, or applicable state or federal laws. Each committee shall maintain its rules for governance in a written scope document that is approved by the Board of Directors.

7.3 **Ad-Hoc Support Committees**. The Board or its committees may, from time to time, appoint ad-hoc committees to research and/or advise it on compliance or technical issues or matters, among other things. Such ad-hoc committees may be formed on an as-needed basis and may vary in makeup depending on the needs of the Board or its committees.

ARTICLE VIII - MISCELLANEOUS

8.1 **Conflicts of Interest.** All Directors, Alternate Directors, Customer Advisors, Board Advisors, and Board committee representatives shall comply with the Corporation's Standards of Conduct policy that prohibits conflicts of interest, as such conflicts could cast doubt on the ability of such persons to act with total objectivity with regard to the overall interests of the Corporation.

8.2 **Contracts**. The Board of Directors may authorize any officer or agent of the Corporation, in addition to the officers so authorized by these Bylaws, to enter into any contract or execute and deliver any instrument in the name of and on behalf of the Corporation, and such authority may be general or confined to specific instances.

8.3 **Checks, Drafts, etc**. All checks, drafts, or orders for the payment of money, notes or other evidences of indebtedness issued in the name of the Corporation, shall be signed by an authorized officer or agent of the Corporation and in such manner as shall from time to time be determined by resolution of the Executive Committee. In the absence of such determination by the Executive Committee, such instruments shall be signed by the Board's Secretary-Treasurer, the Corporation's President, or the Corporation's Finance Director, as stipulated by the Executive Committee. The Corporation's Finance Director may arrange audits of financial records, sign appropriate documents, and perform such duties normally performed by the Board's Secretary-Treasurer, except duties assigned to the Corporation's President.

8.4 **Deposits**. All funds of the Corporation shall be deposited from time to time to the credit of the Corporation in such banks, trust companies, or other depositories as the Corporation's President may select.

8.5 **Books and Records**. The Corporation shall keep correct and complete books and records of account and shall also keep minutes of the proceedings of the Board of Directors and committees having any of the authority of the Board of Directors, and shall keep at its registered or principal office a record giving the names and addresses of the Directors. All books and records of the Corporation may be inspected by any Director, or agent or attorney representing any Director, for any proper purpose at any reasonable time.

8.6 **Seal**. The corporate seal shall be in circular form and shall have inscribed thereon the name of the Corporation, the words "Corporate Seal", and such other word or words, if any, as may be determined by the Board of Directors to be inscribed thereon.

8.7 **Fiscal Year.** The fiscal year of the Corporation shall begin on the first day of January and end on the last day of December in each year.

ARTICLE IX - EXPENSES

9.1 **Allocation of Specific Expenses.** The expenses of Directors and Board Officers shall be borne by that person's regular employer.

9.2 **Statutory Functions.** The Corporation anticipates that as a general rule all of its expenses shall be incurred in the furtherance of statutory activities pursuant to Section 215 of the Federal Power Act, and that all such expenses shall be funded by NERC, subject to FERC approval.

9.3 **Non-Statutory Functions.** Notwithstanding Section 9.2, the Board of Directors may from time to time authorize the Corporation to participate in non-statutory activities (i.e., activities not described in Section 215 of the Federal Power Act). In the event that the Corporation proposes to engage in non-statutory activities, such activities shall be identified in the Corporation's annual business plan that is submitted to NERC and, if approved by NERC, shall be submitted to FERC for approval in advance of engaging in such non-statutory activities. The expenses incurred by the Corporation for any such approved non-statutory activities shall be allocated by the Board of Directors to the beneficiaries of such activities on a basis proposed in the business plan submitted for NERC and FERC approval.

ARTICLE X - DISPUTE RESOLUTION PROCESS

10.1 **Dispute Resolution.** All disputes regarding non-compliance with Reliability Standards shall be handled in accordance with the NERC Rules of Procedure. The

organizational units of the Corporation shall deal with all other disputes within the framework of their respective organizations. For such other disputes, Member Companies of the Corporation are encouraged to utilize the appropriate Dispute Resolution Process within the Corporation prior to seeking resolution at NERC, FERC, or with legal counsel.

ARTICLE XI - DISSOLUTION

11.1 **Dissolution**. The Corporation may be voluntarily dissolved upon unanimous consent of the Board of Directors, and in accordance with Section 55A-14-02 of the North Carolina Nonprofit Corporation Act, as amended from time to time.

11.2 **Distribution of Assets**. Upon dissolution of the Corporation as provided in Section 11.1, the residual assets, after payment of all just obligations, shall be distributed exclusively to organizations which are exempt from federal income tax under Section 501(c)(6) of the Internal Revenue Code of 1986, or corresponding provisions of any subsequent federal tax laws, as the Board of Directors shall determine.

ARTICLE XII - WAIVER OF NOTICE

12.1 **Waiver.** Whenever any notice is required to be given under the provisions of the North Carolina Nonprofit Corporation Act or under the provisions of the articles of incorporation or the Bylaws of the Corporation, a waiver thereof in writing signed by the person or persons entitled to such notice, whether before or after the time stated therein, shall be deemed equivalent to the giving of such notice.

ARTICLE XIII - INDEMNIFICATION

13.1 **Indemnification of Directors, Alternate Directors, Customer Advisors, Board Advisors, Committee Members, Officers, Employees and Agents**. Every person who is, or has served as, a Director, Alternate Director, Customer Advisor, Board Advisor, committee member, Officer, employee, or agent of the Corporation shall be indemnified by the Corporation in the manner and to the extent authorized by the North Carolina Nonprofit Corporation Act. The foregoing rights of indemnification shall be without prejudice to any other rights to which any such Director, Alternate Director, Customer Advisor, Board Advisor, committee member, Officer, employee, or agent may be entitled as a matter of law.

ARTICLE XIV - AMENDMENT OF THE BYLAWS AND ARTICLES OF INCORPORATION

14.1 **Amendment of the Bylaws and Articles of Incorporation**. After a request by twenty percent (20%) of the Board of Directors or an affirmative vote of the Executive Committee, a proposal to amend the Bylaws or the Articles of Incorporation shall be put before the Board of Directors at any regular or special meeting for a vote. Copies of the proposed amendments shall be distributed to the Board of Directors at least thirty (30) days before the meeting at which they are to be considered. An amendment to the Bylaws or the Articles of Incorporation shall be adopted after being approved by a Supermajority vote of the Board of Directors, provided that a quorum is present.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

February 21, 2019

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 TPL-007-3 Transmission System Planned Performance for Geomagnetic Disturbance Events

Dear Ms. Bose:

The North American Electric Reliability Corporation ("NERC") hereby provides notice to the Federal Energy Regulatory Commission ("FERC") regarding Reliability Standard TPL-007-3, Transmission System Planned Performance for Geomagnetic Disturbance Events. Reliability Standard TPL-007-3 adds a regional Variance for Canadian jurisdictions. No changes have been made to any of the continent-wide Requirements of Commission-approved Reliability Standard TPL-007-2.[1]

The standard was developed in accordance with the NERC Rules of Procedure. It was adopted by the NERC Board of Trustees on February 7, 2019. The standard has been submitted to the applicable governmental authorities in Canada for further action.[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 TPL-007-3. 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 Standard TPL-007-3 effective July 1, 2019 in accordance with the Reliability Standard TPL-007-3 implementation plan. As provided in this plan, all U.S. based entities shall continue to follow the phased-in compliance dates of the Reliability Standard TPL-007-2 implementation plan, which is incorporated into

[1] The Commission approved Reliability Standard TPL-007-2 with directives for further modifications in Order No. 851, issued November 15, 2018. *See Geomagnetic Disturbance Reliability Standard; Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events*, Order No. 851, 165 FERC ¶ 61,124 (2018).

[2] NERC's filings to the Canadian governmental authorities are available on NERC's website at: https://www.nerc.com/FilingsOrders/ca/Pages/default.aspx.

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

the Reliability Standard TPL-007-3 implementation plan by reference and attachment. Reliability Standard TPL-007-2 shall be retired immediately prior to the effective date of Reliability Standard TPL-007-3.

NERC provides notice of Reliability Standard TPL-007-3 for informational purposes only.

Respectfully submitted,

/s/ Lauren A. Perotti

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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 WESTERN ELECTRICITY COORDINATING COUNCIL FOR APPROVAL OF PROPOSED REGIONAL RELIABILITY STANDARD IRO-006-WECC-3

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March 6, 2019

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Exhibit E Summary of Development History and Complete Record of Development

Exhibit F Standard Drafting Team Roster for Project WECC-0130 IRO-006-WECC-2, Qualified Transfer Path Unscheduled Flow (USF) Relief Five-Year Review

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. _____**

JOINT PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION AND WESTERN ELECTRICITY COORDINATING COUNCIL FOR APPROVAL OF PROPOSED REGIONAL RELIABILITY STANDARD IRO-006-WECC-3

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 the "Commission") regulations, the North American Electric Reliability Corporation ("NERC")[3] and the Western Electricity Coordinating Council ("WECC") hereby submit proposed Regional Reliability Standard IRO-006-WECC-3 – Qualified Path Unscheduled Flow (USF) Relief for Commission approval. Regional Reliability Standard IRO-006-WECC-3 addresses requests for transmission relief due to unscheduled flow on Qualified Paths in the Western Interconnection. NERC and WECC also request approval of the regional defined term "Qualified Path" to replace the term "Qualified Transfer Path" in the NERC Glossary and for the retirement of certain regional defined terms no longer used in any WECC Regional Reliability Standard.[4]

NERC and WECC request that the Commission approve proposed Regional Reliability Standard IRO-006-WECC-3 (**Exhibit A**) as just, reasonable, not unduly discriminatory or

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1 16 U.S.C. § 824o (2018).

2 18 C.F.R. § 39.5 (2018).

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 *Glossary of Terms Used in NERC Reliability Standards* ("NERC Glossary"), http://www.nerc.com/files/Glossary_of_Terms.pdf. Unless otherwise designated, all capitalized terms used in this document shall have the meaning set forth in the NERC Glossary.

preferential, and in the public interest. NERC and WECC also request approval of the associated implementation plan (**Exhibit B**), and the associated Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") (**Exhibit D**), as detailed in this petition.

As required by Section 39.5(a)[5] of the Commission's regulations, this petition presents the technical basis and purpose of the proposed Regional Reliability Standard, a summary of the development proceedings (**Section III.D** and **Exhibit E**), and a demonstration that the proposed Regional Reliability Standard meets the criteria identified by the Commission in Order No. 672[6] (**Exhibit C**). Proposed Regional Reliability Standard IRO-006-WECC-3 was approved by the WECC Board of Directors on December 5, 2018 and adopted by the NERC Board of Trustees on February 7, 2019.

I. SUMMARY

The purpose of proposed Regional Reliability Standard IRO-006-WECC-3 is to mitigate flows on Qualified Paths to reliable levels during real-time operations. The proposed standard was developed following a periodic review of the currently-effective version of the standard, IRO-006-WECC-2, which became effective in 2014.

As a result of WECC's periodic review, WECC revised the standard to clarify the purpose statement, replace certain defined terms, account for multiple Reliability Coordinators in the Western Interconnection, and conform the standard to the current drafting conventions and template. Proposed Regional Reliability Standard IRO-006-WECC-3 continues to remain more stringent than continent-wide standards and necessary for reliability in the Western

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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 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 PP 262, 321-37 ("Order No. 672"), *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

Interconnection. For these reasons, and as discussed more fully herein, NERC and WECC respectfully request the Commission approve proposed Regional Reliability Standard IRO-006-WECC-3 and the associated elements. 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]

Sandy Mooy*
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Senior Legal Counsel
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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 WECC Regional Reliability Standards development process; and (c) the history of WECC-0130 IRO-006-WECC-2, Qualified Transfer Path Unscheduled Flow (USF) Relief Five-Year Review.

[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.

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 Commission will give due weight to the technical expertise of the ERO with respect to the content of a Reliability Standard.

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8 16 U.S.C. § 824o.

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).

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] The Commission must give due weight to the technical expertise of a Regional Entity, like WECC, that is organized on an Interconnection-wide basis with respect to a Regional Reliability Standard to be applicable within that Interconnection.[16]

B. WECC 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 WECC Reliability Standards Development Procedures ("RSDP").[17] WECC's RSDP provides for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards and thus addresses certain for approving Reliability Standards. The development process is open to any person or entity that is an interested stakeholder. WECC considers the comments of all stakeholders, and a vote of stakeholders and the WECC Board of Directors is required to approve a Regional Reliability Standard. NERC posts each proposed Regional Reliability Standard for an

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14 Section 215(d)(2) of the FPA and 18 C.F.R. § 39.5(a).

15 Order No. 672 at P 291.

16 *Id*. at P 344.

17 The currently-effective WECC RSDP was approved by the Commission on October 27, 2017 (*see N. Am. Elec. Reliability Corp.*, RR17-5-000 (Oct. 27, 2017) (unpublished letter order)) and is available at: http://www.nerc.com/FilingsOrders/us/Regional%20Delegation%20Agreements%20DL/WECC%20RSDP_20171027.pdf.

additional comment period. The NERC Board of Trustees must adopt the Regional Reliability Standard before the Regional Reliability Standard is submitted to the Commission for approval.

C. History of the IRO-006-WECC Standard

The IRO-006-WECC standard was originally developed to mitigate transmission overloads due to unscheduled flow on "Qualified Transfer Paths" (i.e. transfer paths designated by WECC as being qualified for WECC unscheduled flow mitigation). The first version of the Regional Reliability Standard, IRO-006-WECC-1, became effective in 2011.[18] The currently effective version of the standard, IRO-006-WECC-2, became effective in 2014.[19] In approving Regional Reliability Standard IRO-006-WECC-2, the Commission stated, "We believe regional Reliability Standard IRO-006-WECC-2 will help protect and improve reliability in the Western Interconnection by mitigating transmission overloads due to unscheduled flow on Qualified Transfer Paths."[20]

D. Development of the Proposed Regional Reliability Standard

As further described in **Exhibit E** hereto, proposed Regional Reliability Standard IRO-006-WECC-3 was developed in accordance with the WECC RSDP, as part of a five-year review of currently effective Regional Reliability Standard IRO-006-WECC-2. On November 5, 2018, the second draft of proposed Regional Reliability Standard IRO-006-WECC-3 was approved by the WECC ballot body with a 100 percent affirmative vote at 77.6 percent quorum. The WECC Board of Directors approved the regional standard on December 5, 2018. NERC posted the regional standard for a 45-day comment period concluding on January 28, 2019. Commenters

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[18] Regional Reliability Standard IRO-006-WECC-1 was approved by the Commission in Order No. 746. *Western Electric Coordinating Council Qualified Transfer Path Unscheduled Flow Relief Regional Reliability Standard*, Order No. 746, 134 FERC ¶ 61,199 (2011).

[19] Regional Reliability Standard IRO-006-WECC-2 was approved by the Commission on May 13, 2014. *N. Am. Elec. Reliability Corp.*, 147 FERC ¶ 61,112 (2014).

[20] *Id*. at P 9.

agreed that WECC's process was open, inclusive, balanced, transparent, and that due process was followed. The NERC Board of Trustees subsequently adopted the regional standard on February 7, 2019.

IV. JUSTIFICATION FOR APPROVAL

The purpose of proposed Regional Reliability Standard IRO-006-WECC-3 is to mitigate flows on Qualified Paths to reliable levels during real-time operations. The proposed standard would continue to provide specific requirements for acting on requests for unscheduled flow transmission relief on a Qualified Path within the responsible entity's area. Proposed Regional Reliability Standard IRO-006-WECC-3 builds upon the currently effective version of the standard with several improvements to clarify and streamline language. The proposed regional standard continues to remain more comprehensive than its continent-wide counterpart and necessary for reliability in the Western Interconnection. The proposed changes are discussed in more detail below.

A. "Qualified Paths"

In currently effective Regional Reliability Standard IRO-006-WECC-2, the Requirements make reference to Qualified Transfer Paths. The term "Qualified Transfer Path" is defined in the NERC Glossary as "[a] transfer path designated by the WECC Operating Committee as being qualified for WECC unscheduled flow mitigation."[21] At the time Regional Reliability Standard IRO-006-WECC-2 was developed, WECC served as the administrator of the associated Western Interconnection Unscheduled Flow Mitigation Plan (WIUFMP).[22] As of 2018, WECC no longer

[21] *See* NERC Glossary, *supra* n.4.

[22] The Commission approved the currently effective version of the WIUFMP in 2016. *Pacificorp*, 154 FERC ¶ 61,189 (2016). The plan is available at: https://www.wecc.biz/Reliability/12c-FERC%20Accepted%20WIUFMP%202016%2003%2011.pdf.

serves in this role. The NERC Glossary definition of Qualified Transfer Path is therefore out of date.

To address this issue and promote alignment of defined terms across related documents, the defined term Qualified Transfer Path is replaced in proposed Regional Reliability Standard IRO-006-WECC-3 with the proposed term "Qualified Path." The proposed term Qualified Path would have the same definition as it has in the FERC-approved WIUFMP, which is: "[a] transmission element, or group of transmission elements that has qualified for inclusion into the WIUFMP."[23] NERC and WECC respectfully request that the Commission approve the defined term "Qualified Path" for inclusion in the NERC Glossary to replace the term "Qualified Transfer Path".

B. Purpose and Applicability

The purpose statement of proposed Regional Reliability Standard IRO-006-WECC-3 has been revised and clarified to state that the purpose of the standard is "to mitigate flows on Qualified Paths to reliable levels during real-time operations."[24] The proposed standard would continue to be applicable to Reliability Coordinators and Balancing Authorities in the Western Interconnection.

C. Requirements

Proposed Regional Reliability Standard IRO-006-WECC-3 includes revisions that clarify the obligations of Reliability Coordinators (Requirement R1) and Balancing Authorities (Requirement R2) with respect to acting on requests for unscheduled flow transmission relief on Qualified Paths. These revisions are as follows:

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[23] The WIUFMP describes, among other things, the process by which an Administrator for the plan is chosen and the criteria that must be met for including paths as Qualified Paths.

[24] *See* Exhibit A.

Requirement R1

> **R1.** Each Reliability Coordinator receiving a request for Curtailments for unscheduled flow transmission relief on a Qualified Path within its Reliability Coordinator Area shall either approve or deny ~~a~~that request within five minutes of ~~receiving the request for unscheduled flow transmission relief from the Transmission Operator of a Qualified Transfer Path that will result in the calculation of a Relief Requirement.~~receipt.

Requirement R2

> **R2.** Each Balancing Authority receiving an approved request for unscheduled flow transmission relief on a Qualified Path per Requirement R1, shall perform any ~~combination~~ of the following actions ~~meeting the Relief Requirement upon receiving a request for relief as described in Requirement R1~~to meet that request:
>
> • Approve curtailment requests to the schedules as submitted
>
> • Implement alternative actions

The proposed revisions highlighted above do not substantively alter the fundamental obligations of Reliability Coordinators and Balancing Authorities. Rather, the revisions help to streamline the language and improve readability. This is accomplished by, among other things, reducing the use of defined terms that are now used only in Regional Reliability Standard IRO-006-WECC-2. By revising the Regional Reliability Standard, WECC proposes to retire regional defined terms Contributing Schedule and Relief Requirement. Additionally, WECC proposes to replace the defined term Qualified Transfer Path, as discussed above.

WECC has determined that three other WECC regional defined terms may also be formally retired from the NERC Glossary at this time. These defined terms were used in retired Regional Reliability Standard IRO-006-WECC-1, but are no longer used in any regional or continent-wide Reliability Standard. These terms include: (i) Qualified Controllable Device; (ii) Transfer Distribution Factor; and (iii) Qualified Transfer Path Curtailment Event.

D. Enforceability of Proposed Regional Reliability Standard IRO-006-WECC-3

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. In proposed Regional Reliability Standard IRO-006-WECC-3, the VRFs remain unchanged from the related Requirements in currently-effective Regional Reliability Standard IRO-006-WECC-2. The VSL section has been modified to match the revised language of underlying Requirements. The VRFs and VSLs for the proposed Regional Reliability Standard continue to 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.[25]

V. EFFECTIVE DATE

NERC respectfully requests that the Commission approve the proposed implementation plan, provided in **Exhibit B** hereto. Under the proposed implementation plan, proposed Regional Reliability Standard IRO-006-WECC-3 would become effective on the first day of the second calendar quarter after Commission approval. Currently effective Regional Reliability Standard IRO-006-WECC-2 would be retired immediately prior to the effective date of proposed Regional Reliability Standard IRO-006-WECC-3.

[25] 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 IRO-006-WECC-3 in **Exhibit A**;
- the other associated elements in the proposed Regional Reliability Standard in **Exhibit A**, including the VRFs and VSLs;
- the revisions to the NERC Glossary, as described above;
- the proposed implementation plan, included in **Exhibit B**; and
- the retirement of Regional Reliability Standard IRO-006-WECC-2.

Respectfully submitted,

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Date: March 6, 2019

Exhibit A

Proposed Regional Reliability Standard IRO-006-WECC-3
Qualified Path Unscheduled Flow (USF) Relief

Exhibit A

Proposed Regional Reliability Standard IRO-006-WECC-3
Qualified Path Unscheduled Flow (USF) Relief
Clean

A. Introduction

1. **Title:** Qualified Path Unscheduled Flow (USF) Relief

2. **Number:** IRO-006-WECC-3

3. **Purpose:** To mitigate flows on Qualified Paths to reliable levels during Real-time operations.

4. **Applicability**

   4.1. Reliability Coordinator

   4.2 Balancing Authority

5. **Effective Date:** The first day of the second quarter following applicable regulatory approval. See Implementation Plan.

B. Requirements and Measures

R1. Each Reliability Coordinator receiving a request for Curtailments for unscheduled flow transmission relief on a Qualified Path within its Reliability Coordinator Area shall either approve or deny that request within five minutes of receipt. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M1. Each Reliability Coordinator receiving a request for Curtailments for unscheduled flow transmission relief on a Qualified Path within its Reliability Coordinator Area, per requirement R1, will have evidence that it approved or denied that request within five minutes of receipt. Evidence may include, but is not limited to documentation of either an active or passive approval.

R2. Each Balancing Authority receiving an approved request for unscheduled flow transmission relief on a Qualified Path per Requirement R1, shall perform any of the following actions to meet that request: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

- Approve curtailment requests to the schedules as submitted
- Implement alternative actions

M2. Each Balancing Authority receiving an approved request for unscheduled flow transmission relief on a Qualified Path per Requirement R1, will have

evidence that it performed the actions allowed in Requirement R2, to meet that request.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention:

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

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

- Each Reliability Coordinator and each Balancing Authority shall keep data or evidence to show compliance with Requirements R1 and R2 for three calendar years or for the duration of any Compliance Enforcement Authority investigation, whichever is longer.
- If the Reliability Coordinator or Balancing Authority is found noncompliant, it shall keep information related to the noncompliance until found compliant or for the duration specified above, whichever is longer.

1.3. Compliance Monitoring and Enforcement Program

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

Violation Severity Levels

	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Real-time Operations	Medium	Not Applicable	Not Applicable	Not Applicable	There shall be a Severe level of noncompliance if there is one instance during a calendar month in which the Reliability Coordinator approved (actively or passively) or denied a request for unscheduled flow transmission relief on a Qualified Path greater than five minutes after receipt that request.
R2	Real-time Operations	Medium	There shall be a Lower Level of noncompliance if there is less than 100% relief requirement provided but greater than or equal to 90% relief requirement provided or the relief requirement was less	There shall be a Moderate Level of noncompliance if there is less than 90% relief requirement provided but greater than or equal to 75% relief requirement provided.	There shall be a High Level of noncompliance if there is less than 75% relief requirement provided but greater than or equal to 60% relief requirement provided.	There shall be a Severe Level of noncompliance if there is less than 60% relief requirement provided.

	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			than 5 MW and was not fully provided.			

D. Regional Variances

None.

E. Associated Documents

Western Interconnection Unscheduled Flow Mitigation Plan (WIUFMP).

Version History

Version	Date	Action	Change Tracking
1	April 16, 2008	Permanent Replacement Standard for IRO-STD-006-0	
1	February 10, 2009	Adopted by NERC Board of Trustees	
1	March 17, 2011	FERC Order 746 issued by FERC approving IRO-006-WECC-1 (FERC approval effective on May 24, 2011)	
1	May 2, 2012	Updated the requirements to R1. and R2. instead of R.1. and R1.2.	
1	July 1, 2011	Effective Date	No Change
2	February 7, 2013	Adopted by NERC Board of Trustees	
2	May 13, 2014	FERC letter order issued approving IRO-006-WECC-2 (effective July 1, 2014).	
3	February 7, 2019	Adopted by the NERC Board of Trustees	Five-year review. Defined term "Qualified Transfer Path" changed to "Qualified Path" as included in the Western Interconnection Unscheduled Flow Mitigation Plan, as approved by FERC. The following defined terms were retired: 1) Qualified Transfer Path, 2) Contributing Schedule, 3) Qualified Controllable Device, 4) Relief Requirement, 5) Transfer Distribution Factor, and 6) Qualified Transfer Path Curtailment Event.

Exhibit A

Proposed Regional Reliability Standard IRO-006-WECC-3
Qualified Path Unscheduled Flow (USF) Relief

Redline

A. ~~A.~~ Introduction

1. **Title:** Qualified ~~Transfer~~ Path Unscheduled Flow (USF) Relief

2. **Number:** IRO-006-WECC-~~2~~3

3. **Purpose:** ~~Mitigation of transmission overloads due to unscheduled flow~~To mitigate flows on Qualified ~~Transfer~~ Paths~~.~~ to reliable levels during real-time operations

4. **Applicability**

   4.1. ~~Balancing Authority~~

   ~~4.2~~ Reliability Coordinator

   4.2 Balancing Authority

5. **Effective Date:** ~~On the latter of the~~The first day of the ~~first~~second quarter ~~at least 45 days after Regulatory approval, or upon complete implementation of~~ following applicable ~~webSAS changes and FERC approval of this standard and the revised Unscheduled Flow Mitigation~~regulatory approval. See Implementation Plan ~~Documents.~~.

B. ~~B.~~ Requirements and Measures

R1. Each Reliability Coordinator receiving a request for Curtailments for unscheduled flow transmission relief on a Qualified Path within its Reliability Coordinator Area shall either approve or deny ~~a~~that request within five minutes of ~~receiving the request for unscheduled flow transmission relief from the Transmission Operator of a Qualified Transfer Path that will result in the calculation of a Relief Requirement.~~receipt. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M1. Each Reliability Coordinator receiving a request for Curtailments for unscheduled flow transmission relief on a Qualified Path within its Reliability Coordinator Area, per requirement R1, will have evidence that it approved or denied that request within five minutes of receipt. Evidence may include, but is not limited to documentation of either an active or passive approval.

R2. Each Balancing Authority receiving an approved request for unscheduled flow transmission relief on a Qualified Path per Requirement R1, shall perform any ~~combination~~ of the following actions ~~meeting the Relief Requirement upon receiving a request for relief as described in Requirement R1~~to meet that request: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

- Approve curtailment requests to the schedules as submitted
- Implement alternative actions

~~C. Measures~~

~~**M1.** The Reliability Coordinator shall~~ **M2.** Each Balancing Authority receiving an approved request for unscheduled flow transmission relief on a Qualified Path per Requirement R1, will have evidence that it ~~approved or denied~~performed the ~~request within five minutes of receiving a request for relief,~~actions allowed in ~~accordance with Requirement R1. Evidence may include, but is not limited to, documentation of either an active or passive approval.~~

~~Each Balancing Authority shall have evidence that it provided the Relief~~ Requirement ~~through Contributing Schedules curtailments, alternative actions, or a combination that collectively meets the Relief Requirement as directed in Requirement R.2.~~R2, to meet that request.

C. ~~D.~~ Compliance

1. Compliance Monitoring Process~~:~~

1.1. Compliance Enforcement Authority:

- ~~Regional Entity~~
- ~~If the Responsible Entity works for the Regional Entity, then the Regional Entity will establish an agreement with the ERO or another entity approved by the ERO and FERC (i.e., another Regional Entity) to be responsible for compliance enforcement.~~

~~If the Responsible Entity is also a Regional Entity, the ERO or a Regional Entity approved by the ERO and FERC or other applicable governmental authorities shall serve as the~~ 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~~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 ~~complaint~~compliant for the full ~~-~~-time period since the last audit.

~~Each Balancing Authority and Reliability Coordinator~~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 Balancing Authority and~~ Each Reliability Coordinator and each Balancing Authority shall ~~retain~~keep data or evidence to show compliance with Requirements R1 and R2, for three calendar years or for the duration of any Compliance Enforcement Authority investigation~~;~~, whichever is longer.
- If ~~a Balancing Authority or~~ the Reliability Coordinator or Balancing Authority is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the duration specified above, whichever is longer.

1.3. Compliance Monitoring and Enforcement Program

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

Violation Severity Levels

	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL

~~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:~~

~~Compliance shall be determined by a single event, per path, per calendar month (at a minimum) provided at least one event occurs in that month.~~

~~R1~~	Real Time Operations	Medium	Not Applicable	Not Applicable	Not Applicable	There shall be a Severe level of non-compliance if there is one instance during a calendar month in which the

						Reliability Coordinator approved (actively or passively) or denied a request for unscheduled flow transmission relief on a Qualified Path, greater than five minutes after receipt that request.
R2	Real Time Operations	Medium	There shall be a Lower Level of non-compliance if there is less than 100% relief requirement provided but greater than or equal to 90% relief requirement provided or the relief requirement was less than 5 MW and was not fully provided.	There shall be a Moderate Level of non-compliance if there is less than 90% relief requirement provided but greater than or equal to 75% relief requirement provided.	There shall be a High Level of non-compliance if there is less than 75% relief requirement provided but greater than or equal to 60% relief requirement provided.	There shall be a Severe Level of non-compliance if there is less than 60% relief requirement provided.

D. Regional Variances

None.

E. Associated Documents

Western Interconnection Unscheduled Flow Mitigation Plan, (WIUFMP)

Version History

Version	Date	Action	Change Tracking
1	April 16, 2008	Permanent Replacement Standard for IRO-STD-006-0	
1	February 10, 2009	Adopted by NERC Board of Trustees	
1	March 17, 2011	FERC Order 746 issued by FERC approving IRO-006-WECC-1 (FERC approval effective on May 24, 2011)	
1	May 2, 2012	Updated the requirements to R1. and R2. instead of R.1. and R1.2.	
1	July 1, 2011	Effective Date	No ~~change~~Change
2	February 7, 2013	Adopted by NERC Board of Trustees	
2	May 13, 2014	FERC letter order issued approving IRO-006-WECC-2 (effective July 1, 2014).	
3	February 7, 2019	Adopted by the NERC Board of Trustees	Five-year review. Defined term "Qualified Transfer Path" changed to "Qualified Path" as included in the Western Interconnection Unscheduled Flow Mitigation Plan, as approved by FERC. The following defined terms were retired: 1) Qualified Transfer Path, 2) Contributing Schedule, 3) Qualified Controllable Device, 4) Relief Requirement, 5) Transfer Distribution

			Factor, and 6) Qualified Transfer Path Curtailment Event.

Exhibit B

Implementation Plan

Implementation Plan

WECC-0130 IRO-006-WECC-3
Qualified Transfer Path Unscheduled Flow (USF) Relief
Five-year Review

Standards Authorization Request

WECC-0130 IRO-006-WECC-3 Five-year Review SAR

Approvals Required

- WECC Board of Directors — December 5, 2018
- NERC Board of Trustees — Pending
- FERC — Pending

Applicable Entities

4. Applicability
- **4.1** Reliability Coordinator
- **4.2** Balancing Authority

Conforming Changes to Other Standards and the NERC Glossary of Terms Used in Reliability Standards

No conforming changes to other standards are required to implement this project; however, changes to the NERC Glossary of Terms Used in Reliability Standards (Glossary) will be required.

Of the six following terms, the first five would be retired because they are no longer used in any NERC Standards. The sixth term, "Qualified Transfer Path," would be retired and replaced with the term "Qualified Path" included in the FERC-approved Western Interconnection Unscheduled Flow Mitigation Plan (WIUFMP).

1. Contributing Schedule
2. Qualified Controllable Device
3. Relief Requirement
4. Transfer Distribution Factor
5. Qualified Transfer Path Curtailment Event[1]

[1] This term was added to the Implementation Plan in response to comments received in Posting 2.

6. Qualified Transfer Path

The proposed definition for Qualified Path, as currently used in the FERC-approved WIUFMP, is as follows:

"Qualified Path (QP): A transmission element, or group of transmission elements that has qualified for inclusion into the Western Interconnection Unscheduled Flow Mitigation (WIUFMP).[2]

Proposed Effective Date

The Effective Date is proposed to be the first day of the second quarter following applicable regulatory approval.

Justification

The WECC-0130, IRO-006-WECC-3, Qualified Transfer Path Unscheduled Flow (USF) Relief, Five-year Review Drafting Team (DT) reviewed NERC Standards, both in effect and those standards approved by the NERC Board of trustees but pending regulatory disposition. The DT concluded that the proposed changes would have no impact on peripheral standards, nor would the changes add any new burden to the Applicable Entities.

Consideration of Early Compliance

The drafting team foresees no concerns with early compliance.

Required Retirements

The currently approved standard (IRO-006-WECC-2) should be retired immediately prior to the Effective Date of this version, IRO-006-WECC-3. No other retirements or modifications to standards are needed.

Please refer to the above section *Conforming Changes to Other Standards and NERC Glossary of Terms Used in Reliability Standards* for details on adjustments to Glossary terms.

[2] Additional details on proposed Glossary changes are contained in WECC-0130 IRO-006-WECC-3, Five-year Review, Attachment R2 – Posting 2 Response to Comments.

Exhibit C

Order No. 672 Criteria

Order 672 Criteria

WECC-0130 IRO-006-WECC-3
Qualified Transfer Path Unscheduled Flow (USF) Relief
Five-year Review

The North American Electric Reliability Corporation (NERC) is responsible for ensuring that the Reliability Standards, Violation Risk Factors (VRF), Violation Severity Levels (VSL), definitions, Variances, and Interpretations developed by drafting teams are developed in accordance with NERC processes. These standards must also meet NERC's benchmarks for Reliability Standards, as well as criteria for governmental approval.

In Federal Energy Regulatory Commission (FERC) Order No. 672,[1] FERC identified criteria that it will use to analyze proposed Reliability Standards for approval to ensure they are just, reasonable, not unduly discriminatory or preferential, and in the public interest. The discussion below identifies these factors, and explains how the proposed Reliability Standard meets or exceeds the criteria:

1. Proposed Reliability Standards must be designed to achieve a specified reliability goal.

The proposed Reliability Standard must address a reliability concern that falls within the requirements of Section 215 of the Federal Power Act. That is, it must provide for the reliable operation of Bulk Power System facilities. It may not extend beyond reliable operation of such facilities or apply to other facilities. Such facilities include all those necessary for operating an interconnected electric energy transmission network, or any portion of that network, including control systems. The proposed Reliability Standard may apply to any design of planned additions or modifications of such facilities that is necessary to provide for reliable operation. It may also apply to Cybersecurity protection. Order No. 672 at P 321.

Further, 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. NERC Reliability Principles[2]

The Purpose of WECC IRO-006-WECC-3 is to "mitigate flows on Qualified Paths to reliable levels during real-time operations."

[1] FERC Order 672
[2] NERC Reliability Principles

Of the eight NERC Reliability Principles, this standard addresses Reliability Principle 1, which states:

Reliability 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.

2. Proposed Reliability Standards must contain a technically sound method to achieve the goal.

The proposed Reliability Standard must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve this goal. Although any person may propose a topic for a Reliability Standard to the Electric Reliability Organization (ERO), in the ERO's process, the specific proposed Reliability Standard should be developed initially by persons within the electric power industry and community with a high level of technical expertise and be based on sound technical and engineering criteria. It should be based on actual data and lessons learned from past operating incidents, where appropriate. The process for ERO approval of a proposed Reliability Standard should be fair and open to all interested persons. Order No. 672 at P 324.

Standard Development

This proposed Reliability Standard was developed using the NERC and Western Electricity Coordinating Council (WECC) Standards development processes approved by FERC and in effect at each point in the process. Among other things, these processes include drafting of the standard by a drafting team composed of subject matter experts (SME); biographies of those SMEs are provided with this filing.

These processes also include repeated public iterative comment/response cycles whereby comments are received from the industry, and responses to those comments are provided by the drafting team.

Technically Sound

On March 17, 2011, FERC approved IRO-006-WECC-1 with an effective date of May 24, 2011.[3] The purpose of the standard was to "mitigate transmission overloads due to unscheduled flow on a transfer path designated by WECC as being qualified for unscheduled flow mitigation."[4] After due diligence, FERC concluded that IRO-006-WECC-1 represented an improvement to reliability.[5]

On May 13, 2017, FERC held that Version 2 of the standard (IRO-006-WECC-2) was just, reasonable, not unduly discriminatory or preferential, in the public interest, and that the standard would "protect and improve reliability in the Western Interconnection by mitigating transmission overloads due to unscheduled flow on Qualified Transfer Paths."[6]

[3] FERC Order 746
[4] FERC Order 746, Summary
[5] FERC Order 746, P28
[6] FERC Letter Order. Docket No. RD14-9-000, P9

IRO-006-WECC-3 retains the reliability related content of its predecessor while updating the document's template, syntax, structure, and eliminating obsolete definitions.

3. Proposed Reliability Standards must be applicable to users, owners, and operators of the bulk power system, and not others.

The proposed Reliability Standard may impose a requirement on any user, owner, or operator of such facilities, but not on others. Order No. 672 at P 322.

The Applicability section of the proposed standard is as follows:

4. Applicability[7]

4.1. Reliability Coordinator

4.2 Balancing Authority

4. Proposed Reliability Standards must be clear and unambiguous as to what is required and who is required to comply.

The proposed Reliability Standard should be clear and unambiguous regarding what is required and who is required to comply. Users, owners, and operators of the Bulk Power System must know what they are required to do to maintain reliability. Order No. 672 at P 325.

This project was developed using the WECC Reliability Standards Development Procedures (Procedures) as approved by WECC/NERC and FERC. Per the Procedures, the project was posted for two 30-day public comment periods.[8] None of the comments received raised the issue of ambiguity. Each requirement continues to state the Applicable Entity required to act and the act that is required.

All comments received on the project can be viewed in their original format on the WECC-0130 project page under the "Submit and review Comments" accordion.[9]

5. Proposed Reliability Standards must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation.

The possible consequences, including range of possible penalties, for violating a proposed Reliability Standard should be clear and understandable by those who must comply. Order No. 672 at P 326.

This project makes no changes to the Violation Risk Factors.

This project makes no change to the *levels* of the Violation Severity Levels (VSL); however, the syntax in the VSL table was updated and use of the defined term Relief Requirement was converted to a lowercase use because the defined term is proposed for retirement.

[7] In Version 2, the order of Applicable Entities is Balancing Authority followed by Reliability Coordinator. The order is reversed in Version 3 to match the order in which the entities appear in the Requirements.
[8] Posting 1 opened May 22, 2018 and closed June 22, 2018. Posting 2 opened July 18, 2018 and closed August 20, 2018.
[9] https://www.wecc.biz/Standards/Pages/WECC-0130.aspx

6. Proposed Reliability Standards must identify a clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non-preferential manner.

There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. It should contain or be accompanied by an objective measure of compliance so that it can be enforced and so that enforcement can be applied in a consistent and non-preferential manner. Order No. 672 at P 327.

In IRO-006-WECC-2, Requirement R2 lacked a designated Measure.

In IRO-006-WECC-3, Measure M1 was adjusted to current drafting conventions and a designated Measure was added for Requirement R2.

7. Proposed Reliability Standards should achieve a reliability goal effectively and efficiently - but does not necessarily have to reflect "best practices" without regard to implementation cost.

The proposed Reliability Standard does not necessarily have to reflect the optimal method, or "best practice," for achieving its reliability goal without regard to implementation cost or historical regional infrastructure design. It should however achieve its reliability goal effectively and efficiently. Order No. 672 at P 328.

IRO-006-WECC-3 does not represent an appreciable change in the practical application of the standard. During the two posting periods, no concerns were raised regarding implementation costs or historical regional infrastructure.

IRO-006-WECC-3 reaches its goals effectively and efficiently by using existing business practices. Through joint coordination of the Balancing Authority and the Reliability Coordinator, as required under the proposed standard, potential transmission overloading would be uniformly mitigated.

8. Proposed Reliability Standards cannot be "lowest common denominator," i.e., cannot reflect a compromise that does not adequately protect bulk power system reliability.

The proposed Reliability Standard must not simply reflect a compromise in the ERO's Reliability Standard development process based on the least effective North American practice—the so-called "lowest common denominator"—if such practice does not adequately protect Bulk Power System reliability. Although the Commission will give due weight to the technical expertise of the ERO, we will not hesitate to remand a proposed Reliability Standard if we are convinced it is not adequate to protect reliability. Order No. 672 at P 329.

IRO-006-WECC-3 does not represent an appreciable change in the practical application of the standard.

9. Proposed Reliability Standards may consider costs to implement for smaller entities but not at consequence of less than excellence in operating system reliability.

A proposed Reliability Standard may consider the size of the entity that must comply with the Reliability Standard and the cost to those entities of implementing the proposed Reliability Standard.

However, the ERO should not propose a "lowest common denominator" Reliability Standard that would achieve less than excellence in operating system reliability solely to protect against reasonable expenses for supporting this vital national infrastructure. For example, a small owner or operator of the Bulk Power System must bear the cost of complying with each Reliability Standard that applies to it. Order No. 672 at P 330.

During the development of the project, the industry raised no such concerns.

10. Proposed Reliability Standards must be designed to apply throughout North America to the maximum extent achievable with a single reliability standard while not favoring one area or approach.

A proposed Reliability Standard should be designed to apply throughout the interconnected North American Bulk Power System, to the maximum extent this is achievable with a single Reliability Standard. The proposed Reliability Standard should not be based on a single geographic or regional model but should take into account geographic variations in grid characteristics, terrain, weather, and other such factors; it should also take into account regional variations in the organizational and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard. Order No. 672 at P 331.

In the Order 740 Remand at P4, the Commission states that:

"Reliability Standards that the ERO proposes to the Commission may include Reliability Standards that are proposed to the ERO by a Regional Entity… When the ERO reviews a regional Reliability Standard that would be applicable on an interconnection-wide basis and that has been proposed by a Regional Entity organized on an interconnection-wide basis, the ERO must rebuttably presume that the regional Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest. In turn, the Commission must give "due weight" to the technical expertise of the ERO and of a Regional Entity organized on an interconnection-wide basis."

Further, regional entities may propose Regional Reliability Standards that set more stringent reliability requirements than the NERC Reliability Standard or cover matters not covered by an existing NERC Reliability Standard. NERC Rules of Procedure, Section 312, Regional Reliability Standards.

The proposed standard is applicable solely within the Western Interconnection.

The proposed standard is more stringent than existing NERC Reliability Standards.[10]

[10] It should be noted that IRO-006-WECC-3 continues the requirement to act within five minutes of a request, as previously contained in both Version 1 and Version 2. In approving Version 1, FERC stated in Order 746, P11:
"The Standard goes beyond the corresponding NERC Reliability Standard by requiring a reliability coordinator to approve or deny a transmission operator's curtailment request within five minutes."
"Accordingly, the Commission adopts the NOPR proposal and approves regional Reliability Standard IRO-006-WECC-1 as just, reasonable, not unduly discriminatory or preferential, and in the public interest."

The proposed standard addresses matter not covered in any existing NERC Reliability Standard by providing an alternative approach to meeting the same reliability objective based on physical differences in the Western Interconnection; specifically, Qualified Paths.

Version 3 proposes to delete the defined term "Qualified Transfer Path" from the NERC Glossary of Terms Used in Reliability Standards and replace it with the more viable term "Qualified Path" as used in the FERC-approved Western Interconnection Unscheduled Flow Mitigation Plan (WIUFMP). The proposed definition is as follows:

"Qualified Path (QP): A transmission element, or group of transmission elements that has qualified for inclusion into the WIUFMP."

11. Proposed reliability standards should cause no undue negative effect on competition or restriction of the grid.

As directed by section 215 of the FPA, the Commission itself will give special attention to the effect of a proposed Reliability Standard on competition. The ERO should attempt to develop a proposed Reliability Standard that has no undue negative effect on competition. Among other possible considerations, a proposed Reliability Standard should not unreasonably restrict available transmission capability on the Bulk Power System beyond any restriction necessary for reliability and should not limit use of the Bulk Power System in an unduly preferential manner. It should not create an undue advantage for one competitor over another. Order No. 672 at P 332

The assigned drafting team does not foresee any negative impacts on competition resulting from the changes proposed for this project.

During the development phase of this project, the industry raised no concerns regarding competition or restrictive use of the grid.

12. The implementation time for the proposed Reliability Standards must be reasonable.

In considering whether a proposed Reliability Standard is just and reasonable, the Commission will consider also the timetable for implementation of the new requirements, including how the proposal balances any urgency in the need to implement it against the reasonableness of the time allowed for those who must comply to develop the necessary procedures, software, facilities, staffing or other relevant capability. Order No. 672 at P 333

In accordance with the WECC Reliability Standards Development Procedures, an implementation plan for the proposed standard was included with Posting 1 of this project. The Implementation Plan is included as Attachment F of this filing.

The proposed effective date for this project is the first day of the second quarter following applicable regulatory approval.

The project drafting team concluded that the proposed changes: 1) would have no impact on peripheral standards, 2) would add no new burden to the Applicable Entities, and 3) could be implemented earlier than requested without resulting in any negative impact to reliability.

13. The Reliability Standard development process must be open and fair.

Further, in considering whether a proposed Reliability Standard meets the legal standard of review, we will entertain comments about whether the ERO implemented its Commission-approved Reliability Standard development process for the development of the proposed Reliability Standard in a proper manner, especially whether the process was open and fair. However, we caution that we will not be sympathetic to arguments by interested parties that choose, for whatever reason, not to participate in the ERO's Reliability Standard development process if it is conducted in good faith in accordance with the procedures approved by the Commission. Order No. 672 at P 334

WECC followed the WECC Reliability Standards Development Procedures (Procedures) approved by FERC in effect at the time of each step in the process.

In accordance with the Procedures, all drafting team meetings are open to the public.

All drafting team meetings were announced via the WECC Standards Email List for the period prescribed in the Procedures. Notice of the meetings was provided to NERC and posted on the WECC Calendar along with meeting minutes.

All meetings were supported by a telephone conference bridge associated with an on-line internet visual capability allowing all participants to see the document(s) as they were being developed. Further, this team held an open-mic Standards Briefing prior to balloting affording the industry an additional opportunity to have its questions addressed.

This project was posted twice for public comment at WECC.

Comments and the associated responses are posted on the WECC Web Site at the WECC-0130 project page on the Submitted and Review Comments accordion.[11] Response to Comments forms were provided with this filing.

In addition to posting under the WECC Procedures, this project was also posted by NERC for 45-days in accordance with NERC's Rules of Procedure and NERC's internal business practices.

14. Proposed Reliability Standards must balance with other vital public interests.

Finally, we understand that at times development of a proposed Reliability Standard may require that a particular reliability goal must be balanced against other vital public interests, such as environmental, social, and other goals. We expect the ERO to explain any such balancing in its application for approval of a proposed Reliability Standard. Order No. 672 at P 335

[11] https://www.wecc.biz/Standards/Pages/WECC-0130.aspx

WECC is not aware of any other vital public interests. No such balancing concerns were raised or noted.

15. Proposed Reliability Standards must consider any other relevant factors.

In considering whether a proposed Reliability Standard is just and reasonable, [FERC] will consider [several] general factors, as well as other factors that are appropriate for the particular Reliability Standard proposed. Order No. 672 at P 323

WECC is not aware of any other general factors in need of consideration.

Exhibit D

Analysis of Violation Severity Levels

VRF and VSL Justification

WECC-0130 IRO-006-WECC-3
Qualified Transfer Path Unscheduled Flow (USF) Relief
Five-year Review

The Violation Risk Factors did not change.

The Violation Severity Levels (VSL) for Requirements R1 and R2 were updated reflecting prose and syntax changes and the proposed retirement of the defined term "Relief Requirement." The severity *levels* did not change.

	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Real-~~-t~~Time Operations	Medium	Not Applicable	Not Applicable	Not Applicable	There shall be a Severe level of non-compliance if there is one instance during a calendar month in which the Reliability Coordinator approved (actively or passively) or denied a request for unscheduled flow transmission relief ~~from the Transmission Operator of a~~ on a Qualified ~~Transfer~~ Path, greater than five minutes after receipt of that request.~~notification from the Transmission Operator of a Qualified Transfer Path.~~
R2	Real-t-~~T~~ime Operations	Medium	There shall be a Lower Level of non-compliance if there is less than 100% r~~R~~elief r~~R~~equirement provided but greater than or equal to 90% r~~R~~elief r~~R~~equirement provided or the r~~R~~elief r~~R~~equirement was less than 5 MW and was not fully provided.	There shall be a Moderate Level of non-compliance if there is less than 90% r~~R~~elief r~~R~~equirement provided but greater than or equal to 75% r~~R~~elief r~~R~~equirement provided.	There shall be a High Level of non-compliance if there is less than 75% r~~R~~elief r~~R~~equirement provided but greater than or equal to 60% r~~R~~elief r~~R~~equirement provided.	There shall be a Severe Level of non-compliance if there is less than 60% r~~R~~elief r~~R~~equirement provided.

Exhibit E

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 IRO-006-WECC-3 is summarized below.

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.[1] The technical expertise of the ERO is derived from the standard drafting team selected by the WECC Standards Committee to lead each project in accordance with Step 3 of the WECC Reliability Standards Development Procedures.[2] For this project, the standard drafting team consisted of industry experts, all with a diverse set of experiences. A roster of the Standard Drafting team members is included in **Exhibit F**.

II. Standard Development History

A. Standard Authorization Request Development

Project WECC-0130 IRO-006-WECC-3 – Qualified Transfer Path Unscheduled Flow Relief was initiated on January 12, 2018 with receipt of a proposed Standards Authorization Request ("SAR"). The WECC Standards Committee formally approved the SAR on January 23, 2018.

B. First Posting – Comment Period

On May 15, 2018, the standard drafting team agreed by consensus to post proposed Regional Reliability Standard IRO-006-WECC-3 for a 30-day comment period.[3] Proposed

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1 Section 215(d)(2) of the Federal Power Act; 16 U.S.C. § 824(d)(2) (2012).

2 The WECC Reliability Standards Development Procedures are available at https://www.wecc.biz/Reliability/Reliability%20Standards%20Development%20Procedures%20-%20FERC%20Approved%20Dec%2023%202014.pdf.

3 Posting materials for this posting and subsequent postings are available on the WECC project page, https://www.wecc.org/Standards/Pages/WECC-0130.aspx.

Regional Reliability Standard IRO-006-WECC-3 was posted for a 30-day comment period from May 22, 2018 through June 22, 2018. Based on the comments received, the standard drafting team determined to make substantive comments to the proposed Regional Reliability Standard. Therefore, the proposed standard was posted for an additional comment period.

C. Second Posting – Comment Period

Proposed Regional Reliability Standard IRO-006-WECC-3 was posted for another public comment period for 30 days from July 18, 2018 through August 20, 2018. WECC received one set of comments.

D. Final Ballot

On September 20, 2018, the WECC Standards Committee approved Regional Reliability Standard IRO-006-WECC-3 to be posted for ballot. The ballot pool opened on September 27, 2018 and closed on October 11, 2018. WECC held a standards briefing on October 17, 2018. The ballot was open from October 19, 2018 through November 2, 2018. Forty-nine individuals joined the ballot pool. Thirty-eight individuals cast votes, providing quorum at 77.6 percent. The standard obtained 38 affirmative votes[4] which was 100 percent of the weighted segment vote.

E. WECC Board of Directors Approval

On December 5, 2018, the WECC Board of Directors approved WECC-130 IRO-006 WECC-3.[5]

F. NERC Comment Period and Board of Trustees Adoption

NERC posted proposed Regional Reliability Standard IRO-006-WECC-3 for a 45-day public comment period from December 14, 2018 through January 28, 2019. The NERC Board of Trustees adopted the proposed Regional Reliability Standard on February 7, 2019.

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4 During the ballot period there were 11 individuals that did not cast a vote.

5 *See* https://www.wecc.org/Administrative/December%202018%20Board%20Material.pdf

Complete Record of Development

Steven Rueckert
155 North 400 West
Salt Lake City, Utah
84103

January 31, 2019

Subject: Notification of Completion
WECC-0130 IRO-006-WECC-3
Qualified Transfer Path Unscheduled Flow (USF) Relief
Five-year Review

To: Ms. Nasheema Santos
NERC Reliability Standards Department
North American Electric Reliability Corporation
3353 Peachtree Rd. NE, North Tower—Suite 600
Atlanta, GA 30326

Dear Nasheema,

WECC is seeking approval by the NERC Board of Trustees, with subsequent disposition by the Federal Energy Regulatory Commission (FERC), to approve IRO-006-WECC-3 Qualified Path Unscheduled Flow (USF) Relief.

In accordance with the Western Electricity Coordinating Council's (WECC) Reliability Standards Development Procedures (Procedures), the WECC-0130 Drafting Team conducted a five-year review of the WECC Regional Reliability Standard (RRS), making the following proposed changes:

- Clarify the Purpose statement.
- Revise Requirement R1 to account for multiple Reliability Coordinators in the Western Interconnection.
- Update the document to the currently approved NERC Reliability Standards template.
- Replace and retire several defined terms (See Attachment F Implementation Plan).
- Update the Measures to conform with NERC's current drafting conventions.
- Add a Measure for Requirement R2.
- Update the Compliance section.
- Update the Violation Severity Level table.

This project passed with a 100 percent affirmative weighted vote. There were no negative votes and no minority positions.

Thank you for your assistance.

Sincerely,

Steven Rueckert
Director of Standards
Western Electricity Coordinating Council

For documentation support please contact W. Shannon Black, at (503) 307-5782.

WECC-0130 IRO-006-WECC-3 Qualified Transfer Path Unscheduled Flow (USF) Relief Five-year Review
SAR – Standard Authorization Request Attachment A (1)
Regional Reliability Standard(s) (Clean Existing) Attachment B (2)
Regional Reliability Standard(s) (Clean Proposed) Attachment C (3)
Regional Reliability Standard(s) (Existing redlined to Proposed) Attachment D (4)
Project Roadmap Attachment E (5)
Implementation Plan Attachment F (6)
VRF & VSL Justification Attachment G (7)
Regional Reliability Standard Submittal Request Attachment H (8)
Order 672 Criteria Attachment I (9)
Drafting Team Roster with Biographies Attachment J (10)
Ballot Pool Members Attachment K (11)
Final Ballot Results Attachment L (12)
Minority Issues Attachment M (13)
Responses to Comments – Posting 1 - WECC Attachment N1 (14)
Responses to Comments – Posting 2 - WECC Attachment N2 (15)

IRO-006-WECC-3	Qualified Path Unscheduled Flow (USF) Relief	Standard Under Development	12/14/18 – 1/28/19	Info (16) IRO-006-WECC-3 Clean (17) | Redline (18) Submit Comments Unofficial Comment Form (Word) (19) Comments Received (20)

Attachment A
Standard Authorization Request

WECC-0130 IRO-006-WECC-3
Qualified Transfer Path Unscheduled Flow (USF) Relief
Five-year Review

This Standard Authorization Request (SAR) was received on January 12, 2018, and deemed complete the same day. The SAR was approved by the WECC Standards Committee (WSC) on January 23, 2018.

Introduction

This project is a request to review IRO-006-WECC-2, Qualified Transfer Path Unscheduled Flow (USF) Relief in accordance with the prescribed five-year review requirement contained in the WECC Reliability Standards Development Procedures (Procedures).

Requester Information

1. Provide your contact information and your alternate's contact information:
    - Your First Name: W. Shannon
    - Your Last Name: Black
    - Your Email Address: sblack@wecc.biz
    - Your Phone Number: (503) 307-5782
    - Organization Name: WECC
    - Alternate's First Name: Steven
    - Alternate's Last Name: Rueckert
    - Alternate's Email Address: steve@wecc.biz
    - Alternate's Phone Number: (801) 883-6878

Type of Request

2. Specify the type of request: (Select one)
    - Request for five-year review

Create, Modify or Retire a Document

Provide the requested information for your request to create, modify, or retire the document.

3. Requested Action: (Select one)
    - Request for five-year review
4. Document Type: (Select one)
    - WECC Regional Reliability Standard (RRS)
5. Issue: Specify what industry problem this request is trying to resolve.

In accordance with the WECC Reliability Standards Development Procedures (Procedures), *Maintenance of RRSs and CRTs*, "The WSC shall ensure that each [Regional Reliability Standard] and each [WECC Criterion] is reviewed at least every five years from the effective date of the most recent version of the document under review."

No specific issues are identified.

6. Proposed Remedy: Specify how this request proposes to address the issue described.

   This Standard Authorization Request (SAR) meets the five-year Procedural requirement.

7. Functions: Each function will be reviewed if affected.

   - Balancing Authority
   - Reliability Coordinator

8. Detailed Description:

   The Federal Energy Regulatory Commission (FERC) approved Version 1 of the Regional Reliability Standard (RRS) in Order No. 746. Version 2 was approved via FERC Letter Order Docket No. RD14-9-000 issued on May 13, 2014.

   Version 2 provides for mitigation of transmission overloads due to unscheduled flow on Qualified Transfer Paths and helps ensure mitigation of transmission overloads due to unscheduled flow on Qualified Transfer Paths in the Western Interconnection.[1]

9. Affected Reliability Principles: Which of the following reliability principles is MOST affected by this request? (Select one)

   - **Reliability Principle 1** — *Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.*

Document Information

Specify the document's title, document number, and affected section regarding the request.

10. Document Title: See above.

[1] Glossary of Terms Used in NERC Reliability Standards, WECC Regional Terms, Updated July 3, 2018

Reference Uploads

Please reference or upload any affected NERC or WECC Regional Reliability Standards, WECC Criterion, WECC Policies, WECC Guidelines, white papers, technical reports, or other relevant documents. If this request is based on a conflict of law, please include a copy of, or accessible reference to, the specific law or regulatory mandate in conflict.

11. Provide additional comments (if needed)

    NA

A. Introduction

1. **Title:** Qualified Transfer Path Unscheduled Flow (USF) Relief

2. **Number:** IRO-006-WECC-2

3. **Purpose:** Mitigation of transmission overloads due to unscheduled flow on Qualified Transfer Paths.

4. **Applicability**

   4.1. Balancing Authority

   4.2 Reliability Coordinator

5. **Effective Date:** On the latter of the first day of the first quarter at least 45 days after Regulatory approval, or upon complete implementation of applicable webSAS changes and FERC approval of this standard and the revised Unscheduled Flow Mitigation Plan Documents.

B. Requirements

R1. Each Reliability Coordinator shall approve or deny a request within five minutes of receiving the request for unscheduled flow transmission relief from the Transmission Operator of a Qualified Transfer Path that will result in the calculation of a Relief Requirement. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

R2. Each Balancing Authority shall perform any combination of the following actions meeting the Relief Requirement upon receiving a request for relief as described in Requirement R1: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

- Approve curtailment requests to the schedules as submitted
- Implement alternative actions

C. Measures

M1. The Reliability Coordinator shall have evidence that it approved or denied the request within five minutes of receiving a request for relief, in accordance with Requirement R1. Evidence may include, but is not limited to, documentation of either an active or passive approval.

M1.1.1 Each Balancing Authority shall have evidence that it provided the Relief Requirement through Contributing Schedules curtailments, alternative actions, or a combination that collectively meets the Relief Requirement as directed in Requirement R.2.

D. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority

- Regional Entity
- If the Responsible Entity works for the Regional Entity, then the Regional Entity will establish an agreement with the ERO or another entity approved by the ERO and FERC (i.e., another Regional Entity) to be responsible for compliance enforcement.
- If the Responsible Entity is also a Regional Entity, the ERO or a Regional Entity approved by the ERO and FERC or other applicable governmental authorities shall serve as the Compliance Enforcement Authority.

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 complaint for the full time period since the last audit.

- Each Balancing Authority and Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- The Balancing Authority and Reliability Coordinator shall retain data or evidence for three calendar years or for the duration of any Compliance Enforcement Authority investigation; whichever is longer.
- If a Balancing Authority or Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the duration specified above, whichever is longer.

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

1.3. Compliance Monitoring and Assessment Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information:

Compliance shall be determined by a single event, per path, per calendar month (at a minimum) provided at least one event occurs in that month.

Version History

Version	Date	Action	Change Tracking
1	April 16, 2008	Permanent Replacement Standard for IRO-STD-006-0	
1	February 10, 2009	Adopted by NERC Board of Trustees	
1	March 17, 2011	FERC Order 746 issued by FERC approving IRO-006-WECC-1 (FERC approval effective on May 24, 2011)	
1	May 2, 2012	Updated the requirements to R1. and R2. instead of R.1. and R1.2.	
1	July 1, 2011	Effective Date	No change
2	February 7, 2013	Adopted by NERC Board of Trustees	
2	May 13, 2014	FERC letter order issued approving IRO-006-WECC-2 (effective July 1, 2014).	

	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Real Time Operations	Medium	Not Applicable	Not Applicable	Not Applicable	There shall be a Severe level of non-compliance if there is one instance during a calendar month in which the Reliability Coordinator approved (actively or passively) or denied a request for unscheduled flow transmission relief from the Transmission Operator of a Qualified Transfer Path, greater than five minutes after receipt of notification from the Transmission Operator of a Qualified Transfer Path.
R2	Real Time Operations	Medium	There shall be a Lower Level of non-compliance if there is less than 100% Relief Requirement provided but greater than or equal to 90% Relief Requirement provided or the Relief Requirement was less	There shall be a Moderate Level of non-compliance if there is less than 90% Relief Requirement provided but greater than or equal to 75% Relief Requirement provided.	There shall be a High Level of non-compliance if there is less than 75% Relief Requirement provided but greater than or equal to 60% Relief Requirement provided.	There shall be a Severe Level of non-compliance if there is less than 60% Relief Requirement provided.

	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			than 5 MW and was not fully provided.			

A. Introduction

1. **Title:** Qualified Path Unscheduled Flow (USF) Relief

2. **Number:** IRO-006-WECC-3

3. **Purpose:** To mitigate flows on Qualified Paths to reliable levels during Real-time operations.

4. **Applicability**

   4.1. Reliability Coordinator

   4.2 Balancing Authority

5. **Effective Date:** The first day of the second quarter following applicable regulatory approval. See Implementation Plan.

B. Requirements and Measures

R1. Each Reliability Coordinator receiving a request for Curtailments for unscheduled flow transmission relief on a Qualified Path within its Reliability Coordinator Area shall either approve or deny that request within five minutes of receipt. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M1. Each Reliability Coordinator receiving a request for Curtailments for unscheduled flow transmission relief on a Qualified Path within its Reliability Coordinator Area, per requirement R1, will have evidence that it approved or denied that request within five minutes of receipt. Evidence may include, but is not limited to documentation of either an active or passive approval.

R2. Each Balancing Authority receiving an approved request for unscheduled flow transmission relief on a Qualified Path per Requirement R1, shall perform any of the following actions to meet that request: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

- Approve curtailment requests to the schedules as submitted
- Implement alternative actions

M2. Each Balancing Authority receiving an approved request for unscheduled flow transmission relief on a Qualified Path per Requirement R1, will have

evidence that it performed the actions allowed in Requirement R2, to meet that request.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention:

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

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

- Each Reliability Coordinator and each Balancing Authority shall keep data or evidence to show compliance with Requirements R1 and R2 for three calendar years or for the duration of any Compliance Enforcement Authority investigation, whichever is longer.
- If the Reliability Coordinator or Balancing Authority is found noncompliant, it shall keep information related to the noncompliance until found compliant or for the duration specified above, whichever is longer.

1.3. Compliance Monitoring and Enforcement Program

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

Violation Severity Levels

	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Real-time Operations	Medium	Not Applicable	Not Applicable	Not Applicable	There shall be a Severe level of noncompliance if there is one instance during a calendar month in which the Reliability Coordinator approved (actively or passively) or denied a request for unscheduled flow transmission relief on a Qualified Path greater than five minutes after receipt that request.
R2	Real-time Operations	Medium	There shall be a Lower Level of noncompliance if there is less than 100% relief requirement provided but greater than or equal to 90% relief requirement provided or the relief requirement was less	There shall be a Moderate Level of noncompliance if there is less than 90% relief requirement provided but greater than or equal to 75% relief requirement provided.	There shall be a High Level of noncompliance if there is less than 75% relief requirement provided but greater than or equal to 60% relief requirement provided.	There shall be a Severe Level of noncompliance if there is less than 60% relief requirement provided.

	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			than 5 MW and was not fully provided.			

D. Regional Variances

None.

E. Associated Documents

Western Interconnection Unscheduled Flow Mitigation Plan (WIUFMP).

Version History

Version	Date	Action	Change Tracking
1	April 16, 2008	Permanent Replacement Standard for IRO-STD-006-0	
1	February 10, 2009	Adopted by NERC Board of Trustees	
1	March 17, 2011	FERC Order 746 issued by FERC approving IRO-006-WECC-1 (FERC approval effective on May 24, 2011)	
1	May 2, 2012	Updated the requirements to R1. and R2. instead of R.1. and R1.2.	
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2	February 7, 2013	Adopted by NERC Board of Trustees	
2	May 13, 2014	FERC letter order issued approving IRO-006-WECC-2 (effective July 1, 2014).	
3	TBD		Five-year review. Defined term "Qualified Transfer Path" changed to "Qualified Path" as included in the Western Interconnection Unscheduled Flow Mitigation Plan, as approved by FERC. The following defined terms were retired: 1) Qualified Transfer Path, 2) Contributing Schedule, 3) Qualified Controllable Device, 3) Relief Requirement, 4) Transfer Distribution Factor.

WECC Standard IRO-006-WECC-~~2~~ 3 – Qualified ~~Transfer~~ Path Unscheduled Flow (USF) Relief

A. ~~A.~~ Introduction

1. **Title:** Qualified ~~Transfer~~ Path Unscheduled Flow (USF) Relief

2. **Number:** IRO-006-WECC-~~2~~3

3. **Purpose:** ~~Mitigation of transmission overloads due to unscheduled flow~~To mitigate flows on Qualified ~~Transfer~~ Paths~~.~~ to reliable levels during real-time operations

4. **Applicability**

   4.1. ~~Balancing Authority~~

   ~~4.2~~ Reliability Coordinator

   4.2 Balancing Authority

5. **Effective Date:** ~~On the latter of the~~The first day of the ~~first~~second quarter ~~at least 45 days after Regulatory approval, or upon complete implementation of~~ following applicable ~~webSAS changes and FERC approval of this standard and the revised Unscheduled Flow Mitigation~~regulatory approval. See Implementation Plan ~~Documents.~~.

B. ~~B.~~ Requirements and Measures

R1. Each Reliability Coordinator receiving a request for Curtailments for unscheduled flow transmission relief on a Qualified Path within its Reliability Coordinator Area shall either approve or deny ~~a~~that request within five minutes of ~~receiving the request for unscheduled flow transmission relief from the Transmission Operator of a Qualified Transfer Path that will result in the calculation of a Relief Requirement.~~receipt. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M1. Each Reliability Coordinator receiving a request for Curtailments for unscheduled flow transmission relief on a Qualified Path within its Reliability Coordinator Area, per requirement R1, will have evidence that it approved or denied that request within five minutes of receipt. Evidence may include, but is not limited to documentation of either an active or passive approval.

R2. Each Balancing Authority receiving an approved request for unscheduled flow transmission relief on a Qualified Path per Requirement R1, shall perform any ~~combination~~ of the following actions ~~meeting the Relief Requirement upon receiving a request for relief as described in Requirement R1~~to meet that request: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

- Approve curtailment requests to the schedules as submitted
- Implement alternative actions

~~C. Measures~~

~~**M1.** The Reliability Coordinator shall~~ **M2.** Each Balancing Authority receiving an approved request for unscheduled flow transmission relief on a Qualified Path per Requirement R1, will have evidence that it ~~approved or denied~~performed the ~~request within five minutes of receiving a request for relief,~~actions allowed in ~~accordance with Requirement R1. Evidence may include, but is not limited to, documentation of either an active or passive approval.~~

~~Each Balancing Authority shall have evidence that it provided the Relief~~ Requirement ~~through Contributing Schedules curtailments, alternative actions, or a combination that collectively meets the Relief Requirement as directed in Requirement R.2.~~R2, to meet that request.

C. ~~D.~~ Compliance

1. Compliance Monitoring Process~~:~~

1.1. Compliance Enforcement Authority:

- ~~Regional Entity~~
- ~~If the Responsible Entity works for the Regional Entity, then the Regional Entity will establish an agreement with the ERO or another entity approved by the ERO and FERC (i.e., another Regional Entity) to be responsible for compliance enforcement.~~

~~If the Responsible Entity is also a Regional Entity, the ERO or a Regional Entity approved by the ERO and FERC or other applicable governmental authorities shall serve as the~~ 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~~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 ~~complaint~~compliant for the full ~~-~~-time period since the last audit.

~~Each Balancing Authority and Reliability Coordinator~~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 Balancing Authority and~~ Each Reliability Coordinator and each Balancing Authority shall ~~retain~~keep data or evidence to show compliance with Requirements R1 and R2, for three calendar years or for the duration of any Compliance Enforcement Authority investigation~~;~~, whichever is longer.
- If ~~a Balancing Authority or~~ the Reliability Coordinator or Balancing Authority is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the duration specified above, whichever is longer.

1.3. Compliance Monitoring and Enforcement Program

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

Violation Severity Levels

	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL

~~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:~~

~~Compliance shall be determined by a single event, per path, per calendar month (at a minimum) provided at least one event occurs in that month.~~

~~R1~~	Real Time Operations	Medium	Not Applicable	Not Applicable	Not Applicable	There shall be a Severe level of non-compliance if there is one instance during a calendar month in which the

						Reliability Coordinator approved (actively or passively) or denied a request for unscheduled flow transmission relief on a Qualified Path, greater than five minutes after receipt that request.
R2	Real Time Operations	Medium	There shall be a Lower Level of non-compliance if there is less than 100% relief requirement provided but greater than or equal to 90% relief requirement provided or the relief requirement was less than 5 MW and was not fully provided.	There shall be a Moderate Level of non-compliance if there is less than 90% relief requirement provided but greater than or equal to 75% relief requirement provided.	There shall be a High Level of non-compliance if there is less than 75% relief requirement provided but greater than or equal to 60% relief requirement provided.	There shall be a Severe Level of non-compliance if there is less than 60% relief requirement provided.

D. Regional Variances

None.

E. Associated Documents

Western Interconnection Unscheduled Flow Mitigation Plan, (WIUFMP)

Version History

Version	Date	Action	Change Tracking
1	April 16, 2008	Permanent Replacement Standard for IRO-STD-006-0	
1	February 10, 2009	Adopted by NERC Board of Trustees	
1	March 17, 2011	FERC Order 746 issued by FERC approving IRO-006-WECC-1 (FERC approval effective on May 24, 2011)	
1	May 2, 2012	Updated the requirements to R1. and R2. instead of R.1. and R1.2.	
1	July 1, 2011	Effective Date	No ~~change~~Change
2	February 7, 2013	Adopted by NERC Board of Trustees	
2	May 13, 2014	FERC letter order issued approving IRO-006-WECC-2 (effective July 1, 2014).	
3	TBD		Five-year review. Defined term "Qualified Transfer Path" changed to "Qualified Path" as included in the Western Interconnection Unscheduled Flow Mitigation Plan, as approved by FERC. The following defined terms were retired: 1) Qualified Transfer Path, 2) Contributing Schedule, 3) Qualified Controllable Device, 3) Relief Requirement, 4) Transfer Distribution Factor.

Attachment E
Project Roadmap

WECC-0130 IRO-006-WECC-3
Qualified Transfer Path Unscheduled Flow (USF) Relief
Five-year Review

Project Roadmap

Description of Current Draft

Per the WECC Reliability Standards Development Procedures (Procedures), this is a mandated five-year review. The WECC-0130 Standard Authorization Request (SAR) did not identify any specific concerns, other than addressing definitions.

This project proposes to:

- Clarify the Purpose statement.
- Revise Requirement R1 to account for multiple Reliability Coordinators in the Western Interconnection.
- Update the document to the currently approved NERC Reliability Standards template.
- Replace and retire several defined terms. (See Attachment F—Implementation Plan.)
- Update the Measures to conform with NERC's current drafting conventions.
- Add a Measure for Requirement R2.
- Update the Compliance section.
- Update the Violation Severity Level table.

In drafting this project, the WECC-0130 Drafting Team (DT) concluded that addressing changes based on the Enhanced Curtailment Calculator (ECC) efforts that are underway in the Western Interconnection would be premature. This project does not preclude an iterative Standard Authorization Request for that purpose.[1]

[1] The ECC objectives are broader than Qualified Paths address in the WECC Interconnection Unscheduled Flow Mitigation Plan (WIUFMP) and are not fully developed as of the conclusion of this project. The primary objectives of the ECC: 1) provide operators with the ability to see exactly what is contributing to flows on the transmission system (including generation, load, interchange schedules) to better enable efficient and reliable actions for mitigating excessive flows contributing to SOL exceedances; 2) provide updated tool to support the Unscheduled Flow Mitigation Plan (UFMP) requirements with increased accuracy achieved by using real-time topology, load, and generation, 3) provide operators with a tool for being predictive by looking into future hours to understand expected transmission flows, and, 4) provide users with the ability to take appropriate actions, such as curtail schedules or adjust generation, in a fair and equitable manner to mitigate SOL exceedances.

Actions Completed	Date Completed
Standards Authorization Request (SAR) received/deemed complete	January 12, 2018
WECC Standards Committee (WSC) approved the SAR	January 23, 2018
Notice of Solicitation—WECC-0130 Drafting Team	January 31, 2018
Drafting Team (DT) meeting	April 10, 2018
Drafting Team (DT) meeting	April 17, 2018
Drafting Team (DT) meeting	May 8, 2018
Drafting Team (DT) meeting	May 15, 2018
Posting 1—Opened	May 22, 2018
Posting 1—Closed	June 22, 2018
Drafting Team (DT) meeting	June 28, 2018
Posting 2—Opened	July 18, 2018
Posting 2—Closed	August 20, 2018
Drafting Team (DT) meeting	September 6, 2018
Drafting Team (DT) meeting	September 14, 2018
WSC approved for ballot	September 20, 2018
Notice of Ballot Pool Forming/Notice of Ballot	September 25, 2018
Ballot Pool opened	September 27, 2018
Notice of Standards Briefing	September 28, 2018
Ballot Pool closed	October 11, 2018
Standards Briefing	October 17, 2018
Ballot opened	October 19, 2018
Ballot closed	November 2, 2018
WSC approves forwarding to WECC Board of Directors (Board)	November 27, 2018
Board approves for NERC/FERC disposition	December 5, 2018
Posting 1—NERC 45 days—open	December 14, 2018
Posting 1—NERC 45 days—closed	January 28, 2019
WECC filed with NERC	January 31, 2019

Anticipated Actions	Target Date
NERC Board of Trustees	February 7, 2019
FERC disposition	TBD

Attachment F
Implementation Plan
WECC-0130 IRO-006-WECC-3
Qualified Transfer Path Unscheduled Flow (USF) Relief
Five-year Review

Standards Authorization Request

WECC-0130 IRO-006-WECC-3 Five-year Review SAR

Approvals Required

- WECC Board of Directors — December 5, 2018
- NERC Board of Trustees — Pending
- FERC — Pending

Applicable Entities

4. Applicability

4.1 Reliability Coordinator

4.2 Balancing Authority

Conforming Changes to Other Standards and the NERC Glossary of Terms Used in Reliability Standards

No conforming changes to other standards are required to implement this project; however, changes to the NERC Glossary of Terms Used in Reliability Standards (Glossary) will be required.

Of the six following terms, the first five would be retired because they are no longer used in any NERC Standards. The sixth term, "Qualified Transfer Path," would be retired and replaced with the term "Qualified Path" included in the FERC-approved Western Interconnection Unscheduled Flow Mitigation Plan (WIUFMP).

1. Contributing Schedule
2. Qualified Controllable Device
3. Relief Requirement
4. Transfer Distribution Factor
5. Qualified Transfer Path Curtailment Event[1]

[1] This term was added to the Implementation Plan in response to comments received in Posting 2.

6. Qualified Transfer Path

The proposed definition for Qualified Path, as currently used in the FERC-approved WIUFMP, is as follows:

"Qualified Path (QP): A transmission element, or group of transmission elements that has qualified for inclusion into the Western Interconnection Unscheduled Flow Mitigation (WIUFMP).[2]

Proposed Effective Date

The Effective Date is proposed to be the first day of the second quarter following applicable regulatory approval.

Justification

The WECC-0130, IRO-006-WECC-3, Qualified Transfer Path Unscheduled Flow (USF) Relief, Five-year Review Drafting Team (DT) reviewed NERC Standards, both in effect and those standards approved by the NERC Board of trustees but pending regulatory disposition. The DT concluded that the proposed changes would have no impact on peripheral standards, nor would the changes add any new burden to the Applicable Entities.

Consideration of Early Compliance

The drafting team foresees no concerns with early compliance.

Required Retirements

The currently approved standard (IRO-006-WECC-2) should be retired immediately prior to the Effective Date of this version, IRO-006-WECC-3. No other retirements or modifications to standards are needed.

Please refer to the above section *Conforming Changes to Other Standards and NERC Glossary of Terms Used in Reliability Standards* for details on adjustments to Glossary terms.

[2] Additional details on proposed Glossary changes are contained in WECC-0130 IRO-006-WECC-3, Five-year Review, Attachment R2 – Posting 2 Response to Comments.

Attachment G
VRF and VSL Justification

WECC-0130 IRO-006-WECC-3
Qualified Transfer Path Unscheduled Flow (USF) Relief
Five-year Review

The Violation Risk Factors did not change.

The Violation Severity Levels (VSL) for Requirements R1 and R2 were updated reflecting prose and syntax changes and the proposed retirement of the defined term "Relief Requirement." The severity *levels* did not change.

	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Real-~~-t~~Time Operations	Medium	Not Applicable	Not Applicable	Not Applicable	There shall be a Severe level of non-compliance if there is one instance during a calendar month in which the Reliability Coordinator approved (actively or passively) or denied a request for unscheduled flow transmission relief ~~from the Transmission Operator of a~~ on a Qualified ~~Transfer~~ Path, greater than five minutes after receipt of that request.~~notification from the Transmission Operator of a Qualified Transfer Path.~~
R2	Real-t-~~T~~ime Operations	Medium	There shall be a Lower Level of non-compliance if there is less than 100% r~~R~~elief r~~R~~equirement provided but greater than or equal to 90% r~~R~~elief r~~R~~equirement provided or the r~~R~~elief r~~R~~equirement was less than 5 MW and was not fully provided.	There shall be a Moderate Level of non-compliance if there is less than 90% r~~R~~elief r~~R~~equirement provided but greater than or equal to 75% r~~R~~elief r~~R~~equirement provided.	There shall be a High Level of non-compliance if there is less than 75% r~~R~~elief r~~R~~equirement provided but greater than or equal to 60% r~~R~~elief r~~R~~equirement provided.	There shall be a Severe Level of non-compliance if there is less than 60% r~~R~~elief r~~R~~equirement provided.

Regional Reliability Standard Submittal
Request Attachment H

Region:	**Western Electricity Coordinating Council**
Regional Standard Number:	**IRO-006-WECC-3**[1]
Regional Standard Title:	**Qualified Transfer Path Unscheduled Flow (USF) Relief**
Date Submitted:	**January 31, 2019**
Regional Contact Name:	**Steven Rueckert**
Regional Contact Title:	**Director of Standards**
Regional Contact Telephone Number:	**(801) 883-6878**

Request (check all that apply):

- ☐ Retirement of WECC Regional Reliability Standard
- ☐ Interpret an Existing Standard
- ☐ Approval of a new standard
- ☒ Revision of an existing standard: IRO-006-WECC-2
- ☐ Withdrawal of an existing standard
- ☐ Urgent Action

Has this action been approved by your Board of Directors:

- ☒ Yes
- ☐ No

(If no please indicate date standard action is expected along with the current status (e.g., third comment period with anticipated board approval on mm/dd/year)):

December 5, 2018, Board of Directors Resolution:

[1] Numbering is subject to NERC assignment.

Board Resolution
Resolved, that the Western Electricity Coordinating Council (WECC) Board of Directors (Board), acting upon the recommendation of the WECC Standards Committee (WSC) at the meeting of the Board on December 5, 2018, hereby approves IRO-006-WECC-3, Qualified Path Unscheduled Flow (USF) Relief, as presented and attached hereunto.
[Note: The purpose of the remaining questions is to provide NERC with the information needed to file the regional standard(s) with FERC. The information provided may to a large degree be used verbatim. It is extremely important for the entity submitting this form to provide sufficient detail that clearly delineates the scope and justification of the request.]

Concise statement of the basis and purpose (scope) of request:	IRO-006-WECC- "2" was approved by FERC on May 13, 2014, via letter order, with an effective date of July 1, 2014. Docket No. RD14-9-000. In accordance with the WECC Reliability Standards Development Procedures (Procedures), the WECC Standards Committee shall ensure that each Regional Reliability Standard (RRS) is reviewed at least once every five years from the effective date of the most recent version of the RRS. This project is a result of the required five-year review. The following changes are proposed: • Clarify the Purpose statement. • Update the document to the currently approved NERC Reliability Standards template. • Minor Revisions to R1 to address multiple Reliability Coordinators in the Western Interconnection. • Update the Measures to conform with NERC's current drafting conventions. • Add a Measure for Requirement R2. • Update the Compliance section. • Update the Violation Severity Level table. • Replace and retire several defined terms. (See Attachment F Implementation Plan for greater detail.) Of the six following terms, the first five would be retired because they are no longer used in any NERC Standards. The sixth term, "Qualified Transfer Path," would be retired and replaced with the

	term "Qualified Path" included in the FERC-approved Western Interconnection Unscheduled Flow Mitigation Plan (WIUFMP). 1. Contributing Schedule 2. Qualified Controllable Device 3. Relief Requirement 4. Transfer Distribution Factor 5. Qualified Transfer Path Curtailment Event 6. Qualified Transfer Path The proposed definition for Qualified Path, as currently used in the FERC-approved WIUFMP, is as follows: "Qualified Path (QP): A transmission element, or group of transmission elements that has qualified for inclusion into the WIUFMP."[2]
Concise statement of the justification of the request:	Notes for Petition WECC-0130 IRO-006-WECC-3 Five-year Review 1. This project is required as a mandatory five-year review per the WECC Reliability Standards Development Procedures (Procedures). 2. This project seeks approval of regional Reliability Standard IRO-006-WECC-3 (Qualified Path Unscheduled Flow (USF) Relief), modification and retirement of multiple regional definitions, an implementation plan, modification to the Violation Severity Levels (VSL), and the retirement of regional Reliability Standard IRO-006-WECC-2. 3. The purpose of regional Reliability Standard IRO-006-WECC-3 is to mitigate flows on Qualified Paths to reliable levels during real-time operations. 4. This project seeks retirement of the six terms currently defined in the NERC Glossary of Terms Used in Reliability Standards (Glossary).

[2] Additional details on proposed Glossary changes are contained in WECC-0130 IRO-006-WECC-3, Five Year Review, Attachment R2 – Posting 2 Response to Comments.

	Of the six following terms, the first five would be retired because they are no longer used in any NERC Standards. The sixth term, "Qualified Transfer Path," would be retired and replaced with the term "Qualified Path" included in the FERC-approved Western Interconnection Unscheduled Flow Mitigation Plan (WIUFMP). [3] 1. Contributing Schedule 2. Qualified Controllable Device 3. Relief Requirement 4. Transfer Distribution Factor 5. Qualified Transfer Path Curtailment Event[4] 6. Qualified Transfer Path The proposed definition for Qualified Path, as currently used in the FERC-approved WIUFMP, is as follows: "Qualified Path (QP): A transmission element, or group of transmission elements that has qualified for inclusion into the Western Interconnection WIUFMP."[5] 4. This project seeks to update the VSL's to reflect the proposed retirement of the NERC defined term "Relief Requirement" and syntax adjustments made to associated requirements. The VSL *levels* have not been altered. 5. The project seeks an Effective Date of the first day of the second quarter following applicable regulatory approval. 6. Regional Reliability Standard IRO-006-WECC-3 is more comprehensive than the existing continent-wide

[3] The currently approved definition of "Qualified Transfer Path" would be retired in favor of "Qualified Path" as currently used in the FERC-approved WECC Interconnection Unscheduled Mitigation Plan (WIUFMP).
The term "Qualified Transfer Path" is defined as, "[A] transfer path designated by the WECC Operating Committee as being qualified for WECC unscheduled flow mitigation." *See Glossary of Terms Used in NERC Reliability Standards* (updated April 5, 2013) (NERC Glossary). The term "Qualified Path" is defined as, "A transmission element, or group of transmission elements that has qualified for inclusion into the Western Interconnection Unscheduled Flow Mitigation Plan (WIUFMP)." *WECC Interconnection Unscheduled Flow Mitigation Plan, as approved by FERC, effective January 1, 2016.*
[4] This term was added to the Implementation Plan in response to comments received in Posting 2.
[5] Additional details on proposed Glossary changes are contained in WECC-0130 IRO-006-WECC-3, Five-Year Review, Attachment R2—Posting 2 Response to Comments.

	Reliability Standard addressing transmission loading relief, IRO-006-5, in that the regional Reliability Standard includes additional requirements such as requiring the Reliability Coordinator to respond within five minutes of receiving a request for unscheduled flow transmission relief. However, the additional requirement of the regional Reliability Standard does not increase the reporting burden for entities that operate within the Western Interconnection when compared to the current regional Reliability Standard IRO-006-WECC-2.

Attachment I
Order 672 Criteria

WECC-0130 IRO-006-WECC-3
Qualified Transfer Path Unscheduled Flow (USF) Relief
Five-year Review

The North American Electric Reliability Corporation (NERC) is responsible for ensuring that the Reliability Standards, Violation Risk Factors (VRF), Violation Severity Levels (VSL), definitions, Variances, and Interpretations developed by drafting teams are developed in accordance with NERC processes. These standards must also meet NERC's benchmarks for Reliability Standards, as well as criteria for governmental approval.

In Federal Energy Regulatory Commission (FERC) Order No. 672,[1] FERC identified criteria that it will use to analyze proposed Reliability Standards for approval to ensure they are just, reasonable, not unduly discriminatory or preferential, and in the public interest. The discussion below identifies these factors, and explains how the proposed Reliability Standard meets or exceeds the criteria:

1. Proposed Reliability Standards must be designed to achieve a specified reliability goal.

The proposed Reliability Standard must address a reliability concern that falls within the requirements of Section 215 of the Federal Power Act. That is, it must provide for the reliable operation of Bulk Power System facilities. It may not extend beyond reliable operation of such facilities or apply to other facilities. Such facilities include all those necessary for operating an interconnected electric energy transmission network, or any portion of that network, including control systems. The proposed Reliability Standard may apply to any design of planned additions or modifications of such facilities that is necessary to provide for reliable operation. It may also apply to Cybersecurity protection. Order No. 672 at P 321.

Further, 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. NERC Reliability Principles[2]

The Purpose of WECC IRO-006-WECC-3 is to "mitigate flows on Qualified Paths to reliable levels during real-time operations."

[1] FERC Order 672
[2] NERC Reliability Principles

Of the eight NERC Reliability Principles, this standard addresses Reliability Principle 1, which states:

Reliability 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.

2. Proposed Reliability Standards must contain a technically sound method to achieve the goal.

The proposed Reliability Standard must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve this goal. Although any person may propose a topic for a Reliability Standard to the Electric Reliability Organization (ERO), in the ERO's process, the specific proposed Reliability Standard should be developed initially by persons within the electric power industry and community with a high level of technical expertise and be based on sound technical and engineering criteria. It should be based on actual data and lessons learned from past operating incidents, where appropriate. The process for ERO approval of a proposed Reliability Standard should be fair and open to all interested persons. Order No. 672 at P 324.

Standard Development

This proposed Reliability Standard was developed using the NERC and Western Electricity Coordinating Council (WECC) Standards development processes approved by FERC and in effect at each point in the process. Among other things, these processes include drafting of the standard by a drafting team composed of subject matter experts (SME); biographies of those SMEs are provided with this filing.

These processes also include repeated public iterative comment/response cycles whereby comments are received from the industry, and responses to those comments are provided by the drafting team.

Technically Sound

On March 17, 2011, FERC approved IRO-006-WECC-1 with an effective date of May 24, 2011.[3] The purpose of the standard was to "mitigate transmission overloads due to unscheduled flow on a transfer path designated by WECC as being qualified for unscheduled flow mitigation."[4] After due diligence, FERC concluded that IRO-006-WECC-1 represented an improvement to reliability.[5]

On May 13, 2017, FERC held that Version 2 of the standard (IRO-006-WECC-2) was just, reasonable, not unduly discriminatory or preferential, in the public interest, and that the standard would "protect and improve reliability in the Western Interconnection by mitigating transmission overloads due to unscheduled flow on Qualified Transfer Paths."[6]

[3] FERC Order 746
[4] FERC Order 746, Summary
[5] FERC Order 746, P28
[6] FERC Letter Order. Docket No. RD14-9-000, P9

IRO-006-WECC-3 retains the reliability related content of its predecessor while updating the document's template, syntax, structure, and eliminating obsolete definitions.

3. Proposed Reliability Standards must be applicable to users, owners, and operators of the bulk power system, and not others.

The proposed Reliability Standard may impose a requirement on any user, owner, or operator of such facilities, but not on others. Order No. 672 at P 322.

The Applicability section of the proposed standard is as follows:

4. Applicability[7]

4.1. Reliability Coordinator

4.2 Balancing Authority

4. Proposed Reliability Standards must be clear and unambiguous as to what is required and who is required to comply.

The proposed Reliability Standard should be clear and unambiguous regarding what is required and who is required to comply. Users, owners, and operators of the Bulk Power System must know what they are required to do to maintain reliability. Order No. 672 at P 325.

This project was developed using the WECC Reliability Standards Development Procedures (Procedures) as approved by WECC/NERC and FERC. Per the Procedures, the project was posted for two 30-day public comment periods.[8] None of the comments received raised the issue of ambiguity. Each requirement continues to state the Applicable Entity required to act and the act that is required.

All comments received on the project can be viewed in their original format on the WECC-0130 project page under the "Submit and review Comments" accordion.[9]

5. Proposed Reliability Standards must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation.

The possible consequences, including range of possible penalties, for violating a proposed Reliability Standard should be clear and understandable by those who must comply. Order No. 672 at P 326.

This project makes no changes to the Violation Risk Factors.

This project makes no change to the *levels* of the Violation Severity Levels (VSL); however, the syntax in the VSL table was updated and use of the defined term Relief Requirement was converted to a lowercase use because the defined term is proposed for retirement.

[7] In Version 2, the order of Applicable Entities is Balancing Authority followed by Reliability Coordinator. The order is reversed in Version 3 to match the order in which the entities appear in the Requirements.
[8] Posting 1 opened May 22, 2018 and closed June 22, 2018. Posting 2 opened July 18, 2018 and closed August 20, 2018.
[9] https://www.wecc.biz/Standards/Pages/WECC-0130.aspx

6. Proposed Reliability Standards must identify a clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non-preferential manner.

There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. It should contain or be accompanied by an objective measure of compliance so that it can be enforced and so that enforcement can be applied in a consistent and non-preferential manner. Order No. 672 at P 327.

In IRO-006-WECC-2, Requirement R2 lacked a designated Measure.

In IRO-006-WECC-3, Measure M1 was adjusted to current drafting conventions and a designated Measure was added for Requirement R2.

7. Proposed Reliability Standards should achieve a reliability goal effectively and efficiently - but does not necessarily have to reflect "best practices" without regard to implementation cost.

The proposed Reliability Standard does not necessarily have to reflect the optimal method, or "best practice," for achieving its reliability goal without regard to implementation cost or historical regional infrastructure design. It should however achieve its reliability goal effectively and efficiently. Order No. 672 at P 328.

IRO-006-WECC-3 does not represent an appreciable change in the practical application of the standard. During the two posting periods, no concerns were raised regarding implementation costs or historical regional infrastructure.

IRO-006-WECC-3 reaches its goals effectively and efficiently by using existing business practices. Through joint coordination of the Balancing Authority and the Reliability Coordinator, as required under the proposed standard, potential transmission overloading would be uniformly mitigated.

8. Proposed Reliability Standards cannot be "lowest common denominator," i.e., cannot reflect a compromise that does not adequately protect bulk power system reliability.

The proposed Reliability Standard must not simply reflect a compromise in the ERO's Reliability Standard development process based on the least effective North American practice—the so-called "lowest common denominator"—if such practice does not adequately protect Bulk Power System reliability. Although the Commission will give due weight to the technical expertise of the ERO, we will not hesitate to remand a proposed Reliability Standard if we are convinced it is not adequate to protect reliability. Order No. 672 at P 329.

IRO-006-WECC-3 does not represent an appreciable change in the practical application of the standard.

9. Proposed Reliability Standards may consider costs to implement for smaller entities but not at consequence of less than excellence in operating system reliability.

A proposed Reliability Standard may consider the size of the entity that must comply with the Reliability Standard and the cost to those entities of implementing the proposed Reliability Standard.

However, the ERO should not propose a "lowest common denominator" Reliability Standard that would achieve less than excellence in operating system reliability solely to protect against reasonable expenses for supporting this vital national infrastructure. For example, a small owner or operator of the Bulk Power System must bear the cost of complying with each Reliability Standard that applies to it. Order No. 672 at P 330.

During the development of the project, the industry raised no such concerns.

10. Proposed Reliability Standards must be designed to apply throughout North America to the maximum extent achievable with a single reliability standard while not favoring one area or approach.

A proposed Reliability Standard should be designed to apply throughout the interconnected North American Bulk Power System, to the maximum extent this is achievable with a single Reliability Standard. The proposed Reliability Standard should not be based on a single geographic or regional model but should take into account geographic variations in grid characteristics, terrain, weather, and other such factors; it should also take into account regional variations in the organizational and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard. Order No. 672 at P 331.

In the Order 740 Remand at P4, the Commission states that:

"Reliability Standards that the ERO proposes to the Commission may include Reliability Standards that are proposed to the ERO by a Regional Entity… When the ERO reviews a regional Reliability Standard that would be applicable on an interconnection-wide basis and that has been proposed by a Regional Entity organized on an interconnection-wide basis, the ERO must rebuttably presume that the regional Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest. In turn, the Commission must give "due weight" to the technical expertise of the ERO and of a Regional Entity organized on an interconnection-wide basis."

Further, regional entities may propose Regional Reliability Standards that set more stringent reliability requirements than the NERC Reliability Standard or cover matters not covered by an existing NERC Reliability Standard. NERC Rules of Procedure, Section 312, Regional Reliability Standards.

The proposed standard is applicable solely within the Western Interconnection.

The proposed standard is more stringent than existing NERC Reliability Standards.[10]

[10] It should be noted that IRO-006-WECC-3 continues the requirement to act within five minutes of a request, as previously contained in both Version 1 and Version 2. In approving Version 1, FERC stated in Order 746, P11:
"The Standard goes beyond the corresponding NERC Reliability Standard by requiring a reliability coordinator to approve or deny a transmission operator's curtailment request within five minutes."
"Accordingly, the Commission adopts the NOPR proposal and approves regional Reliability Standard IRO-006-WECC-1 as just, reasonable, not unduly discriminatory or preferential, and in the public interest."

The proposed standard addresses matter not covered in any existing NERC Reliability Standard by providing an alternative approach to meeting the same reliability objective based on physical differences in the Western Interconnection; specifically, Qualified Paths.

Version 3 proposes to delete the defined term "Qualified Transfer Path" from the NERC Glossary of Terms Used in Reliability Standards and replace it with the more viable term "Qualified Path" as used in the FERC-approved Western Interconnection Unscheduled Flow Mitigation Plan (WIUFMP). The proposed definition is as follows:

"Qualified Path (QP): A transmission element, or group of transmission elements that has qualified for inclusion into the WIUFMP."

11. Proposed reliability standards should cause no undue negative effect on competition or restriction of the grid.

As directed by section 215 of the FPA, the Commission itself will give special attention to the effect of a proposed Reliability Standard on competition. The ERO should attempt to develop a proposed Reliability Standard that has no undue negative effect on competition. Among other possible considerations, a proposed Reliability Standard should not unreasonably restrict available transmission capability on the Bulk Power System beyond any restriction necessary for reliability and should not limit use of the Bulk Power System in an unduly preferential manner. It should not create an undue advantage for one competitor over another. Order No. 672 at P 332

The assigned drafting team does not foresee any negative impacts on competition resulting from the changes proposed for this project.

During the development phase of this project, the industry raised no concerns regarding competition or restrictive use of the grid.

12. The implementation time for the proposed Reliability Standards must be reasonable.

In considering whether a proposed Reliability Standard is just and reasonable, the Commission will consider also the timetable for implementation of the new requirements, including how the proposal balances any urgency in the need to implement it against the reasonableness of the time allowed for those who must comply to develop the necessary procedures, software, facilities, staffing or other relevant capability. Order No. 672 at P 333

In accordance with the WECC Reliability Standards Development Procedures, an implementation plan for the proposed standard was included with Posting 1 of this project. The Implementation Plan is included as Attachment F of this filing.

The proposed effective date for this project is the first day of the second quarter following applicable regulatory approval.

The project drafting team concluded that the proposed changes: 1) would have no impact on peripheral standards, 2) would add no new burden to the Applicable Entities, and 3) could be implemented earlier than requested without resulting in any negative impact to reliability.

13. The Reliability Standard development process must be open and fair.

Further, in considering whether a proposed Reliability Standard meets the legal standard of review, we will entertain comments about whether the ERO implemented its Commission-approved Reliability Standard development process for the development of the proposed Reliability Standard in a proper manner, especially whether the process was open and fair. However, we caution that we will not be sympathetic to arguments by interested parties that choose, for whatever reason, not to participate in the ERO's Reliability Standard development process if it is conducted in good faith in accordance with the procedures approved by the Commission. Order No. 672 at P 334

WECC followed the WECC Reliability Standards Development Procedures (Procedures) approved by FERC in effect at the time of each step in the process.

In accordance with the Procedures, all drafting team meetings are open to the public.

All drafting team meetings were announced via the WECC Standards Email List for the period prescribed in the Procedures. Notice of the meetings was provided to NERC and posted on the WECC Calendar along with meeting minutes.

All meetings were supported by a telephone conference bridge associated with an on-line internet visual capability allowing all participants to see the document(s) as they were being developed. Further, this team held an open-mic Standards Briefing prior to balloting affording the industry an additional opportunity to have its questions addressed.

This project was posted twice for public comment at WECC.

Comments and the associated responses are posted on the WECC Web Site at the WECC-0130 project page on the Submitted and Review Comments accordion.[11] Response to Comments forms were provided with this filing.

In addition to posting under the WECC Procedures, this project was also posted by NERC for 45-days in accordance with NERC's Rules of Procedure and NERC's internal business practices.

14. Proposed Reliability Standards must balance with other vital public interests.

Finally, we understand that at times development of a proposed Reliability Standard may require that a particular reliability goal must be balanced against other vital public interests, such as environmental, social, and other goals. We expect the ERO to explain any such balancing in its application for approval of a proposed Reliability Standard. Order No. 672 at P 335

[11] https://www.wecc.biz/Standards/Pages/WECC-0130.aspx

WECC is not aware of any other vital public interests. No such balancing concerns were raised or noted.

15. Proposed Reliability Standards must consider any other relevant factors.

In considering whether a proposed Reliability Standard is just and reasonable, [FERC] will consider [several] general factors, as well as other factors that are appropriate for the particular Reliability Standard proposed. Order No. 672 at P 323

WECC is not aware of any other general factors in need of consideration.

Attachment J
Drafting Team Roster

WECC-0130 IRO-006-WECC-3
Qualified Transfer Path Unscheduled Flow Relief
Five-year Review

Below please find a biographical snapshot for the members of the WECC-0130 IRO-006-WECC-3, Qualified Transfer Path Unscheduled Flow Relief, Five-year Review Drafting Team.

Name	Background
Susan Millar, Bonneville Power Administration	Ms. Millar is a Senior Policy Advisor for System Operations at the Bonneville Power Administration. Qualifications include: • Senior Policy Advisor to System Operations on regulatory issues and internal and external initiatives affecting reliable operation of the Bulk Electric System (BES); • Transmission Provider Representative to the WECC Market Interface Committee; • Subject Matter Expert on Open Access Transmission (BPA and Pro-forma) Tariff, including Attachment J concerning Procedures for Parallel Flows; • Active participant in Task Force discussions developing Peak Reliability Enhanced Curtailment Calculator (ECC), including Phase 2, transition from webSAS to webIntegrity implementing the Unscheduled Flow Mitigation Plan (UFMP); and Phase 4, regarding the expansion of ECC tool application to multiple elements/facilities in the Western Interconnection greater than the UFMP Qualified Paths; and • Actively monitoring the entry of new Reliability Coordinator candidates in the Western Interconnection.
Jim Price, California Independent System Operator	Mr. Price is a Senior Advisor in Market Quality and Renewable Integration at the California Independent System Operator (CAISO). Qualifications include: • Bachelor of Science in Engineering and Applied Science from the California Institute of Technology;

	• Master of Science and a Doctor of Philosophy degree in Civil Engineering from Stanford University; • 19 years of experience at the California Public Utilities Commission; • 18 years at the CAISO in Market Operations, Market & Infrastructure Development, and Market Quality & Renewable Integration; • Member and vice chair of Peak Reliability's Enhanced Curtailment Calculator (ECC) Task Force; and • Former chair of the WECC Seams Issues Subcommittee and the Market and Seams Issues Subcommittee.
Gerardo Ugalde, Southwest Power Pool	Mr. Ugalde is a supervisor with the Southwest Power Pool (SPP) where he supervises the calculation of Available Flowgate Capability, Available Transmission Capability, and other related calculations in support of Transmission service and Flowgate capacity. His team works with neighboring systems to create policies determining what constitutes Firm versus Non-Firm, and to better coordinate congestion across the seams. His team also provides technical support to administer the Western Interconnection Unscheduled Flow Mitigation Plan for the Southwest Power Pool. Qualifications include: • Ten years of experience working for the Southwest Power Pool; • Five years of experience in Energy Management System modeling and Network application support; • Three years of experience in markets, primarily supporting congestion management and Security Constrained Economic Dispatch software; • Two years of experience in his current role; • Subject matter expert in evidence production in support of NERC MOD Standards MOD-001-1a, MOD-004-1, MOD-008-1, MOD-029-2a and MOD-030-3; and • Subject matter expert for the Seams group in which he monitors parallel loop flows on neighboring systems, and coordinates congestion management and use tools such as Market-to-Market (M2M) with the Midcontinent Independent System Operator and the IDC Transmission Loading Relief (TLR).

Kathee Downey, PacifiCorp	Ms. Downey is a Transmission Grid Operations Adviser at PacifiCorp. Qualifications include: • Continuing involvement in multiple WECC committees and associated drafting teams relating to WECC Interchange Scheduling and Accounting Sub-Committee (ISAS) and Federal Energy Regulatory Commission (FERC) Order 764; • Current representative on the WECC Operating Committee and ISAS; • Subject matter expert for NERC IRO-006-3, Reliability Coordination, and IRO-006-WECC-2, Qualified Transfer Path Unscheduled Flow Relief; and • Member of the Peak Enhanced Curtailment Calculator Task Force and an end user for the unscheduled flow tool.
Sean Erickson, Western Area Power Administration	Mr. Erickson is a Senior Power Operations Specialist at the Western Area Power Administration. Qualifications include: • Two years of experience as a WECC Reliability Coordinator (2009–2011); • Two years of experience as a WECC Reliability Coordination Operations Engineer (2007–2009); • Four years of experience as an Operations Engineer (2011–2015); • Currently serving as the Transmission Alternate on the WECC Operating Committee as well as the WECC Ballot Body representative for both WECC and NERC; • Previous member of the WECC Performance Work Group during the BAL-001 field trial evaluations; • Previous member of the Path Operator Task Force (POTF) (post-September 8, 2011, NERC/FERC findings and mitigation regarding Path Operations) and the POITF–Implementation Team for the Operational adoption of the POTF findings; and • Contributor to retiring TOP-007-WECC-1a, System Operating Limits.

Attachment K
Ballot Pool

WECC-0130 IRO-006-WECC-3
Qualified Transfer Path Unscheduled Flow (USF) Relief
Five-year Review

Ballot Name: **WECC-0130 IRO-006-WECC-2 Qualified Transfer Path Unscheduled Flow (USF) Relief**

Overview: This project is the result of a mandated five-year review per the WECC Reliability Standards Development Procedures. This project clarifies the Purpose statement, updates the document to the current template, replaces "Qualified Transfer Path" with "Qualified Path," and retires several terms from the NERC Glossary of Terms.

Title	Company	Sector	Vote	Comments	Created By
WECC-0130	Arizona Public Service Company	Load-Serving Entities (LSE)	Yes	0	Vivian Vo
WECC-0130	Arizona Public Service Company	Transmission Owners	Yes	0	Michelle Amarantos
WECC-0130	Arizona Public Service Company	Electric Generators	Yes	0	Kelsi Rigby
WECC-0130	Arizona Public Service Company	Electricity Brokers, Aggregators, and Marketers	Yes	0	Nicholas Kirby
WECC-0130	Balancing Authority of Northern California	Transmission Owners	Yes	0	Joe Tarantino
WECC-0130	Balancing Authority of Northern California	Electricity Brokers, Aggregators, and Marketers	Yes	0	Joe Tarantino

Title	Company	Sector	Vote	Comments	Created By
WECC-0130	Bonneville Power Administration	Electricity Brokers, Aggregators, and Marketers	Yes	0	Andrew Meyers
WECC-0130	Bonneville Power Administration	Transmission Owners	Yes	0	Kammy Rogers-Holliday
WECC-0130	Bonneville Power Administration	Load-Serving Entities (LSE)	Yes	0	Rebecca Berdahl
WECC-0130	British Columbia Hydro & Power Authority	Electric Generators	Yes	0	Adrian Andreoiu
WECC-0130	British Columbia Hydro & Power Authority	Load-Serving Entities (LSE)	Yes	0	Adrian Andreoiu
WECC-0130	British Columbia Hydro & Power Authority	Transmission Owners	Yes	0	Adrian Andreoiu
WECC-0130	California Independent System Operator	Regional Transmission Organizations (RTO) and Independent System Operators (ISO)	Yes	0	Richard Vine
WECC-0130	Idaho Power Company	Electric Generators	Yes	0	Laura Nelson
WECC-0130	Idaho Power Company	Transmission Owners	Yes	0	Laura Nelson
WECC-0130	Idaho Power Company	Load-Serving Entities (LSE)	Yes	0	Laura Nelson

Title	Company	Sector	Vote	Comments	Created By
WECC-0130	Los Angeles Department of Water and Power	Load-Serving Entities (LSE)	0	0	Pjoy Chua
WECC-0130	Los Angeles Department of Water and Power	Electricity Brokers, Aggregators, and Marketers	0	0	Pjoy Chua
WECC-0130	Los Angeles Department of Water and Power	Transmission Owners	0	0	Pjoy Chua
WECC-0130	Los Angeles Department of Water and Power	Electric Generators	0	0	Pjoy Chua
WECC-0130	Platte River Power Authority	Load-Serving Entities (LSE)	Yes	0	Jeff Landis
WECC-0130	Platte River Power Authority	Electricity Brokers, Aggregators, and Marketers	Yes	0	Sabrina Martz
WECC-0130	Platte River Power Authority	Transmission Owners	Yes	0	Matthew Thompson
WECC-0130	Platte River Power Authority	Electric Generators	Yes	0	Tyson Archie
WECC-0130	Public Service Company of Colorado (Xcel Energy)	Electric Generators	Yes	0	Gerry Huitt

Title	Company	Sector	Vote	Comments	Created By
WECC-0130	Public Service Company of Colorado (Xcel Energy)	Electricity Brokers, Aggregators, and Marketers	0	0	Carrie Simpson
WECC-0130	Public Service Company of New Mexico	Electric Generators	Yes	0	Laurie Williams
WECC-0130	Public Service Company of New Mexico	Transmission Owners	Yes	0	Laurie Williams
WECC-0130	Public Service Company of New Mexico	Load-Serving Entities (LSE)	Yes	0	Laurie Williams
WECC-0130	Public Service Company of New Mexico	Electricity Brokers, Aggregators, and Marketers	Yes	0	Laurie Williams
WECC-0130	Sacramento Municipal Utility District	Electric Generators	Yes	0	Joe Tarantino
WECC-0130	Sacramento Municipal Utility District	Transmission Dependent Utilities (TDU)	Yes	0	Joe Tarantino
WECC-0130	Sacramento Municipal Utility District	Transmission Owners	Yes	0	Joe Tarantino
WECC-0130	Sacramento Municipal Utility District	Load-Serving Entities (LSE)	Yes	0	Joe Tarantino
WECC-0130	Sacramento Municipal Utility District	Electricity Brokers, Aggregators, and Marketers	Yes	0	Joe Tarantino

Title	Company	Sector	Vote	Comments	Created By
WECC-0130	Salt River Project	Electricity Brokers, Aggregators, and Marketers	Yes	0	Bobby Olsen
WECC-0130	Salt River Project	Load-Serving Entities (LSE)	Yes	0	Robert Kondziolka
WECC-0130	Salt River Project	Electric Generators	Yes	0	Kevin Nielsen
WECC-0130	Seattle City Light	Transmission Dependent Utilities (TDU)	Yes	0	Hao Li
WECC-0130	Seattle City Light	Transmission Owners	0	0	Tuan Tran
WECC-0130	Seattle City Light	Load-Serving Entities (LSE)	0	0	Tuan Tran
WECC-0130	Seattle City Light	Electricity Brokers, Aggregators, and Marketers	0	0	Charles Freeman
WECC-0130	Tri-State Generation & Transmission - Reliability	Load-Serving Entities (LSE)	0	0	Janelle Gill
WECC-0130	Tucson Electric Power	Electric Generators	Yes	0	John Tolo
WECC-0130	Tucson Electric Power	Transmission Owners	Yes	0	John Tolo
WECC-0130	Tucson Electric Power	Load-Serving Entities (LSE)	Yes	0	John Tolo
WECC-0130	US Bureau of Reclamation	Transmission Owners	0	0	Wendy Center
WECC-0130	US Bureau of Reclamation	Electric Generators	0	0	Wendy Center

Title	Company	Sector	Vote	Comments	Created By
WECC-0130	Western Area Power Administration	Transmission Owners	Yes	0	sean er

Attachment L
Final Ballot Results

WECC-0130 IRO-006-WECC-3
Qualified Transfer Path Unscheduled Flow (USF) Relief
Five-year Review

Ballot Name: **WECC-0130 IRO-006-WECC-3 Qualified Transfer Path Unscheduled Flow (USF) Relief**

Overview: This project is the result of a mandated five-year review per the WECC Reliability Standards Development Procedures. This project clarifies the Purpose statement, updates the document to the current template, replaces "Qualified Transfer Path" with "Qualified Path," and retires several terms from the NERC Glossary of Terms.

Ballot Pool Open:	09/27/2018	Ballot Opened:	10/19/2018
Ballot Pool Closed:	10/11/2018	Ballot Closed:	11/05/2018
Total Ballot Pool:	49	Total Votes:	38
Quorum:	77.6%	Weighted Votes:	100%

Ballot Results: **Pass**

Voting Sectors	Total In Ballot Pool	In Pool Affiliates Excluded	Votes Non-Abstain	Sector Weight	Yes Votes	Weighted Segment Vote	No Votes	Abstain	Total Votes for Quorum	Didn't Vote
Transmission Owners	13		10	1	10	100.0%	0	0	10	3
Reg. Trans. Org. and Ind. Sys. Op.	1		1	0.1	1	10.0%	0	0	1	0
Load-Serving Entities (LSEs)	12		9	0.9	9	90.0%	0	0	9	3
Transmission Dependent Utilities (TDUs)	2		2	0.2	2	20.0%	0	0	2	0
Electric Gen.	11		9	0.9	9	90.0%	0	0	9	2
Elect. Brokers, Aggregators, and Marketers	10		7	0.7	7	70.0%	0	0	7	3
Large Electricity End Users	0		0	0	0	0.0%	0	0	0	0
Small Electricity Users	0		0	0	0	0.0%	0	0	0	0
Fed/State/Prov. Reg./Other Gov.	0		0	0	0	0.0%	0	0	0	0
Regional Entities	0		0	0	0	0.0%	0	0	0	0
Totals	49	0	38	3.8	38	**100.0%**	0	0	38	11

WECC
WESTERN ELECTRICITY COORDINATING COUNCIL
155 North 400 West, Suite 200
Salt Lake City, Utah 84103-1114

Attachment M
Minority Issues

WECC-0130 IRO-006-WECC-3
Qualified Transfer Path Unscheduled Flow (USF) Relief
Five-year Review

Following a ballot period from October 19, 2018, through November 5, 2018, the WECC Ballot Pool approved the requested changes to WECC-0130 IRO-006-WECC-3, Qualified Transfer Path Unscheduled Flow (USF) Relief.

This project passed with a 100 percent affirmative weighted approval.

There were no votes in opposition and no minority positions to address.

WECC

WESTERN ELECTRICITY COORDINATING COUNCIL
155 North 400 West, Suite 200
Salt Lake City, Utah 84103-1114

Attachment N1
Response to Comments

WECC-0130 IRO-006-WECC-3
Qualified Transfer Path Unscheduled Flow (USF) Relief
Five-year Review

Posting 1

The WECC-0130, IRO-006-WECC-3 Qualified Transfer Path Unscheduled Flow Relief Drafting Team (DT) thanks everyone who submitted comments on the proposed project.

Notice

On May 15, 2018, WECC dispatched notice to the WECC Standards Email List that this project was posted for comment from May 22 through June 22, 2018.

The DT asked stakeholders to provide feedback on the project through a standardized electronic template. WECC received comments from three entities as shown in the following table.

Location of Comments

All comments received on the project can be viewed in their original form on the WECC-0130 project page under the "Submit and Review Comments" accordion.

Changes in Response to Comment

The following two highlighted phrases were added to Requirement R1 and M1.

> **R1.** Each Reliability Coordinator receiving a request **for Curtailments** for unscheduled flow transmission relief on a Qualified Path **within its Reliability Coordinator Area** shall either approve or deny that request within five minutes of receipt. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

The word "on" was inserted into the predicate of the Violation Severity Levels table, Severe VSL column resulting in the following:

"…unscheduled flow transmission relief **on** a Qualified Path, greater than five minutes after receipt that request." (Emphasis added.)

Proposed Glossary Changes

In addition to updating the standard, the DT is proposing changes to the NERC Glossary of Terms Used in Reliability Standards (NERC Glossary).

The WECC-0130 Standard Authorization Request (SAR) calls for IRO-006-WECC-2 to be reviewed and updated. IRO-006-WECC-2, Requirement R1 uses the defined terms Qualified Transfer Path (QTP) and Relief Requirement (RR). RR is also used in Requirement R2.

As approved, QTP erroneously states the WECC Operating Committee designates which path is qualified for WECC unscheduled flow mitigation. RR not only incorporates the erroneous QTP by reference, it also incorporates Contributing Schedules that also incorporates the erroneous QTP, creating a flawed circular logic.

A review of the NERC Glossary shows the following terms are impacted by the erroneous incorporation by reference of either the QTP or other documents that no longer exist:

- Contributing Schedule
- Qualified Controllable Device
- Qualified Transfer Path
- Relief Requirement
- Transfer Distribution Factor

Because changes to these terms may have unintended impacts on the Western Interconnection Unscheduled Flow Mitigation Plan (WIUFMP), further discussions will take place to determine the best course of action.

Proposed Change to NERC Glossary: Qualified Path

At a minimum, the DT proposes retirement of the currently approved definition for QTP and replacement with the currently approved definition from the WIUFMP that states:

"Qualified Path (QP): A transmission element, or group of transmission elements that has qualified for inclusion into the WIUFMP."

The drafting team recognizes that replacement of QTP with QP may raise concerns about due process because of the incorporation by reference. Comments on the matter are solicited.

To eliminate the due process concern and any concerns regarding incorporation by reference of the WIUFMP, the DT specifically seeks proposed language to meet the needs of requirements R1 and R2, without referring to a defined term, should such an approach be possible.

Minority View

There was no minority view.

Effective Date and Implementation Plan

The WECC Reliability Standards Development Procedures (Procedures) require an implementation plan to be included in at least one iterative posting of projects developed under those Procedures. An Implementation Plan was posted with Posting 1. No comments were received impacting the Implementation Plan.

The proposed Effective Date is the first day of the second quarter following applicable regulatory approval. The DT foresees no concerns with early compliance.

Action Plan

On July 12, 2018, the WECC-0130 Qualified Transfer Path Unscheduled Flow Relief, Five-year Review Drafting Team (DT) agreed by majority vote to post Posting 2 of the project for a 30-day comment period.

The posting period will open July 18, 2018, and close August 20, 2018. The DT will meet on September 6, 2018, from 2:00 p.m. to 4:00 p.m. (MT) and September 13, 2018, from 10:00 a.m. to 12:00 p.m. (MT), as needed, to discuss disposition of the project.

Comments can be submitted using the green survey buttons located on the Submit and Review Comments accordion of the WECC-0130 project page.

Contacts and Appeals

If you feel your comment has been omitted or overlooked, please contact W. Shannon Black, WECC Consultant. In addition, the WECC Reliability Standards Appeals Process can be found in the Reliability Standards Development Procedures.

WECC Standards Comment Table

Commenter		Organization
1	Todd Komaromy	Arizona Public Service Company
2	Jeremy West	Peak Reliability
3	Jim Price[1]	California Independent System Operator

Index to Questions, Comments, and Responses

Question

1. The Drafting Team welcomes comments on all aspects of the document.

[1] The comments of the CAISO were not submitted via the standardized electronic portal. Rather, they were submitted directly to WECC staff by Mr. Jim Price of the CAISO, via email on June 22, 2018. Mr. Price is a WECC-0130 DT member and was unavailable to attend the June 28, 2018, meeting when comments were addressed.

1. Response Summary

Summary Consideration:	See summary in the preamble of this document.
Commenter / Comment	**Response**
AZPS	AZPS suggests removing the option in R2 to "implement alternative actions". Due to the sophistication of the solutions generated by the webSAS tool and that those solutions now comport with the FERC transmission priority rules, the ability for an entity to take equal and adequate alternative actions no longer seems to be a feasible option.
Thank you for your comments. **Background for Responses** As background for each of the following responses, the Western Interconnection Unscheduled Flow Mitigation Plan (WIUFMP) is a FERC-approved document with an Effective Date of January 1, 2016. The Relief Requirements called for in IRO-006-WECC-2, Requirements R1 and R2 were resident in IRO-006-WECC-1, Attachment 1, WECC Unscheduled Flow Mitigation Summary of Actions; however, that attachment was retired with version 1. **Implement Alternative Actions** It is the default expectation that entities would follow the prescribed action, but “alternate actions” are spelled out in the WIUFMP document, and to strike them would contradict the FERC approved procedure. (See WIUFMP, page 4. “alternate method”)	
Peak Reliability	Peak requests the WECC-0130 Drafting Team consider how the IRO-006 requirements support the potential industry changes with multiple RCs in the Western Interconnection. This evaluation should consider which RCs evaluate a UFMP request and what RC approvals are required (the RC with the Qualified Path in their footprint or more).

Summary Consideration:	See summary in the preamble of this document.		
Commenter / Comment			Response
Multiple RCs Please see response to CAISO that follows. The DT believes that IRO-014-3, Coordination Among Reliability Coordinators, Requirements R1 and R2, currently contains sufficient language to require coordination of multiple RCs. The DT believes that RC coordination activities are best covered in the WIUFMP and extrinsic documents without overly restricting remedial actions within a standard. An example of extrinsic coordination is found in the Western Interconnection Unscheduled Flow Mitigation Plan, (WIUFMP), at page 4, stating, "Upon request from a Transmission Operator to their Reliability Coordinator (RC) for WIUFMP mitigation of flows on a Qualified Path, the applicable RC *will review the request for reliability impacts, coordinate with other RCs as necessary,* and either approve or disapprove the request for Step 4 by thirty minutes after the hour for actions related to the next hour. (Emphasis added.)			
California Independent System Operator			In general, we support the new R1 for IRO-006, which states: "R1. Each Reliability Coordinator receiving a request for unscheduled flow transmission relief on a Qualified Path, shall either approve or deny that request within five minutes of receipt. [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]". A concern is that the current R1 is very specific in being applicable to requests "… that will result in the calculation of a Relief Requirement", i.e., it applies to requests for curtailment at USF step 4 and beyond. The new R1 eliminates that qualifier, so it essentially expands the applicability to USF steps 1, 2, and 3. Requests for curtailment at USF step 4 understandably have urgent timing that makes R1's 5-minute requirement for RC approval an appropriate requirement. Requests for USF steps 1, 2, and 3 should allow more time for the RC to determine the appropriate course of action, and R1's 5-minute requirement for RC

Summary Consideration:	See summary in the preamble of this document.
Commenter / Comment	Response
	approval is not the appropriate requirement. Further, demonstrating compliance regarding requests for schedule curtailments is straight-forward, as the ECC and webSAS tools have logged the time when requests are received and when the RC approves curtailments. The same logging does not occur for USF steps 1, 2, and 3, so it would be less clear how an RC can prove compliance in all instances. Thus, a phrase like the qualifier "... that will result in schedule curtailment" should be retained.

Thank you for your comment.

The following highlighted phrases have been added to the existing Requirement R1 and M1.

The DT believes this adds clarity in implementing unscheduled flow mitigation without incorporating by reference any extrinsic documents, without being overly prescriptive, and while allowing the applicable entity to timely address the need (i.e. the five-minute reference contained in Step 4 of the plan).

The addition of the second phrase "within its Reliability Coordinator Area" further clarifies which Reliability Coordinator (RC) is to act in the event multiple RCs are active in the Western Interconnection.

R1. Each Reliability Coordinator receiving a request **for Curtailments** for unscheduled flow transmission relief on a Qualified Path **within its Reliability Coordinator Area** shall either approve or deny that request within five minutes of receipt. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

Attachment N2
Response to Comments

WECC-0130 IRO-006-WECC-3
Qualified Transfer Path Unscheduled Flow (USF) Relief
Five-year Review

Posting 2

The WECC-0130, IRO-006-WECC-2 Qualified Transfer Path Unscheduled Flow Relief Drafting Team (DT) thanks everyone who submitted comments on the proposed project.

Notice

On July 13, 2018, WECC dispatched notice to the WECC Standards Email List that this project was posted for comment from July 18 through August 20, 2018.

The DT asked stakeholders to provide feedback on the project through a standardized electronic template. WECC received comments from one entity as shown in the following table.

Location of Comments

All comments received on the project can be viewed in their original form on the WECC-0130 project page under the Submit and Review Comments accordion.

Changes in Response to Comment

No changes were made to the standard; however, proposed changes to the WECC Regional Definitions (Regional Glossary) section of the NERC Glossary of Terms Used in Reliability Standards (NERC Glossary) were accepted as follows.

Modification of Qualified Transfer Path

Qualified Transfer Path (QTP) should be deleted and replaced with the Qualified Path definition as used in the Western Interconnection Unscheduled Flow Mitigation Plan (WIUFMP).

Deletion of Contributing Schedule

If the project is approved as proposed in Posting 2, Contributing Schedule (CS) should be deleted from the Regional Glossary because it will no longer be used in any WECC regional standards.

Deletion of Qualified Controllable Device[1]

Qualified Controllable Device (QCD) definitions vary from the Regional Glossary to the WIUFMP. Because the Regional Glossary definition is not used in any WECC regional standards; and, because the WIUFMP has its own FERC-approved definition, QCD should be deleted from the Regional Glossary.

Deletion of Relief Requirement

If the project is approved as proposed in Posting 2, Relief Requirement (RR) should be deleted from the Regional Glossary because it will no longer be used in any WECC regional standards.

Deletion of Transfer Distribution Factor

Transfer Distribution Factor (TDF) is defined differently in the NERC Glossary than in the Regional Glossary. TDF in the Regional Glossary incorporates by reference an extrinsic document that is no longer valid, QTP that is proposed for modification, and CS that is proposed for deletion. In addition to the definitional inaccuracy, if the project is approved as proposed in Posting 2, TDF should be deleted from the Regional Glossary because it will no longer be used in any WECC regional standards.

Deletion of the term from the Regional Glossary will have no impact on the same term in the NERC Glossary.

Deletion of Qualified Transfer Path Curtailment Event

Qualified Transfer Path Curtailment Event (QTPCE) incorporates by reference an extrinsic document that is no longer valid. In addition to the definitional inaccuracy, if the project is approved as proposed in Posting 2, QTPCE should be deleted from the Regional Glossary because it will no longer be used in any WECC regional standards.

Minority View

There was no minority view.

[1] "The WIUFMP process first uses the coordinated operation of Qualified Controllable Devices to change flows on the Qualified Paths. When more relief is required, curtailments may also be issued. Upon approval of a Step 4 request by the RC, the mitigation software will start a prescription of curtailments that will result in the relief requested by the Transmission Operator of the Qualified Path. Balancing Authorities (BA) that receive WIUFMP curtailment prescriptions may act to approve the curtailments, or may provide equivalent relief via an alternate method." Plan, page 3.

Effective Date and Implementation Plan

The WECC Reliability Standards Development Procedures (Procedures) require an implementation plan to be included in at least one iterative posting of projects developed under those Procedures. An Implementation Plan was posted with Posting 1. Retirement of QTPCE will be added to the Implementation Plan.

The proposed Effective Date is the first day of the second quarter following applicable regulatory approval. The DT foresees no concerns with early compliance.

Action Plan

On September 6, 2018, the WECC-0130 Qualified Transfer Path Unscheduled Flow Relief, Five-year Review Drafting Team (DT) agreed by majority vote to forward this project to the WECC Standards Committee with a request for ballot.

The WSC's next planned meeting is on September 20, 2018.

Contacts and Appeals

If you feel your comment has been omitted or overlooked, please contact W. Shannon Black, WECC Consultant. In addition, the WECC Reliability Standards Appeals Process can be found in the Reliability Standards Development Procedures.

WECC Standards Comment Table

Commenter		Organization
1	W. Shannon Black	WECC

Question and Response Summary

The Drafting Team welcomes comments on all aspects of the document.

Summary Consideration:	See summary in the preamble of this document.		
Commenter / Comment			**Response**
WECC			WECC recommends: Modification of the term Qualified Transfer Path. Deletion of: 1) Contributing Schedule, 2) Qualified Controllable Device, 3) Relief Requirement, 4) Transfer Distribution Factor, and 5) Qualified Transfer Path Curtailment Event. Because the software platform will not accommodate the full comments provided by WECC, WECC's comments were provided to each drafting team member via email as well as posted on the WECC-0130 Project Page on the Submit and Review Comments accordion.
The drafting team reviewed the full comments provided by WECC via email and as posted on the WECC-0130 Project Page. The drafting team agreed to adopt WECC's request for changes to the WECC Regional Definitions section of the NERC Glossary of Terms Used in Reliability Standards.			

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Regional Reliability Standards Announcement

Western Electricity Coordinating Council
IRO-006-WECC-3

Comment Period Open through January 28, 2019

Now Available

The Western Electricity Coordinating Council (WECC) requested that NERC post Regional Reliability Standard **IRO-006-WECC-3 - Qualified Path Unscheduled Flow (USF) Relief** for industry review and comment in accordance with the NERC Rules of Procedure.

Background

WECC conducted a mandatory five-year review of Regional Reliability Standard IRO-006-WECC-2. The WECC drafting team made the following changes:

- Clarified the purpose statement;
- Replaced defined term "Qualified Transfer Path" with "Qualified Path" as included in the Western Interconnection Unscheduled Flow Mitigation Plan, approved by the Federal Energy Regulatory Commission.
- Retired the following terms from the NERC Glossary of Terms Used in Reliability Standards because they are either no longer accurate or are no longer used in any standards:
    1. Qualified Transfer Path,
    2. Contributing Schedule,
    3. Qualified Controllable Device,
    4. Relief Requirement,
    5. Transfer Distribution Factor, and
    6. Qualified Transfer Path Curtailment Event.
- Conformed the standard to current drafting conventions and template.

Commenting

Use the Standards Balloting and Commenting System (SBS) to submit comments. If you experience any difficulties using the electronic form, contact Nasheema Santos. The form must be submitted by **8 p.m. Eastern, Monday, January 28, 2019.** 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. Although the technical aspects of this Regional Reliability Standard have been vetted through WECC'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 unofficial comment form.

Documents and information about this project are available on the WECC's Standards Under Development page.

For more information or assistance, contact Manager of Standards Information, Chris Larson (via email) or at (404) 446-9708.

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:** Qualified Path Unscheduled Flow (USF) Relief

2. **Number:** IRO-006-WECC-3

3. **Purpose:** To mitigate flows on Qualified Paths to reliable levels during Real-time operations.

4. **Applicability**

   4.1. Reliability Coordinator

   4.2 Balancing Authority

5. **Effective Date:** The first day of the second quarter following applicable regulatory approval. See Implementation Plan.

B. Requirements and Measures

R1. Each Reliability Coordinator receiving a request for Curtailments for unscheduled flow transmission relief on a Qualified Path within its Reliability Coordinator Area shall either approve or deny that request within five minutes of receipt. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M1. Each Reliability Coordinator receiving a request for Curtailments for unscheduled flow transmission relief on a Qualified Path within its Reliability Coordinator Area, per requirement R1, will have evidence that it approved or denied that request within five minutes of receipt. Evidence may include, but is not limited to documentation of either an active or passive approval.

R2. Each Balancing Authority receiving an approved request for unscheduled flow transmission relief on a Qualified Path per Requirement R1, shall perform any of the following actions to meet that request: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

- Approve curtailment requests to the schedules as submitted
- Implement alternative actions

M2. Each Balancing Authority receiving an approved request for unscheduled flow transmission relief on a Qualified Path per Requirement R1, will have

evidence that it performed the actions allowed in Requirement R2, to meet that request.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention:

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

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

- Each Reliability Coordinator and each Balancing Authority shall keep data or evidence to show compliance with Requirements R1 and R2 for three calendar years or for the duration of any Compliance Enforcement Authority investigation, whichever is longer.
- If the Reliability Coordinator or Balancing Authority is found noncompliant, it shall keep information related to the noncompliance until found compliant or for the duration specified above, whichever is longer.

1.3. Compliance Monitoring and Enforcement Program

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

Violation Severity Levels

	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Real-time Operations	Medium	Not Applicable	Not Applicable	Not Applicable	There shall be a Severe level of noncompliance if there is one instance during a calendar month in which the Reliability Coordinator approved (actively or passively) or denied a request for unscheduled flow transmission relief on a Qualified Path greater than five minutes after receipt that request.
R2	Real-time Operations	Medium	There shall be a Lower Level of noncompliance if there is less than 100% relief requirement provided but greater than or equal to 90% relief requirement provided or the relief requirement was less	There shall be a Moderate Level of noncompliance if there is less than 90% relief requirement provided but greater than or equal to 75% relief requirement provided.	There shall be a High Level of noncompliance if there is less than 75% relief requirement provided but greater than or equal to 60% relief requirement provided.	There shall be a Severe Level of noncompliance if there is less than 60% relief requirement provided.

	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			than 5 MW and was not fully provided.			

D. Regional Variances

None.

E. Associated Documents

Western Interconnection Unscheduled Flow Mitigation Plan (WIUFMP).

Version History

Version	Date	Action	Change Tracking
1	April 16, 2008	Permanent Replacement Standard for IRO-STD-006-0	
1	February 10, 2009	Adopted by NERC Board of Trustees	
1	March 17, 2011	FERC Order 746 issued by FERC approving IRO-006-WECC-1 (FERC approval effective on May 24, 2011)	
1	May 2, 2012	Updated the requirements to R1. and R2. instead of R.1. and R1.2.	
1	July 1, 2011	Effective Date	No Change
2	February 7, 2013	Adopted by NERC Board of Trustees	
2	May 13, 2014	FERC letter order issued approving IRO-006-WECC-2 (effective July 1, 2014).	
3	TBD		Five-year review. Defined term "Qualified Transfer Path" changed to "Qualified Path" as included in the Western Interconnection Unscheduled Flow Mitigation Plan, as approved by FERC. The following defined terms were retired: 1) Qualified Transfer Path, 2) Contributing Schedule, 3) Qualified Controllable Device, 4) Relief Requirement, 5) Transfer Distribution Factor, and 6) Qualified Transfer Path Curtailment Event.

A. ~~A.~~ Introduction

1. **Title:** Qualified ~~Transfer~~ Path Unscheduled Flow (USF) Relief

2. **Number:** IRO-006-WECC-~~2~~3

3. **Purpose:** ~~Mitigation of transmission overloads due to unscheduled flow~~To mitigate flows on Qualified ~~Transfer~~ Paths~~.~~ to reliable levels during real-time operations

4. **Applicability**

   4.1. ~~Balancing Authority~~

   ~~4.2~~ Reliability Coordinator

   4.2 Balancing Authority

5. **Effective Date:** ~~On the latter of the~~The first day of the ~~first~~second quarter ~~at least 45 days after Regulatory approval, or upon complete implementation of~~ following applicable ~~webSAS changes and FERC approval of this standard and the revised Unscheduled Flow Mitigation~~regulatory approval. See Implementation Plan ~~Documents.~~.

B. ~~B.~~ Requirements and Measures

R1. Each Reliability Coordinator receiving a request for Curtailments for unscheduled flow transmission relief on a Qualified Path within its Reliability Coordinator Area shall either approve or deny ~~a~~that request within five minutes of ~~receiving the request for unscheduled flow transmission relief from the Transmission Operator of a Qualified Transfer Path that will result in the calculation of a Relief Requirement.~~receipt. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M1. Each Reliability Coordinator receiving a request for Curtailments for unscheduled flow transmission relief on a Qualified Path within its Reliability Coordinator Area, per requirement R1, will have evidence that it approved or denied that request within five minutes of receipt. Evidence may include, but is not limited to documentation of either an active or passive approval.

R2. Each Balancing Authority receiving an approved request for unscheduled flow transmission relief on a Qualified Path per Requirement R1, shall perform any ~~combination~~ of the following actions ~~meeting the Relief Requirement upon receiving a request for relief as described in Requirement R1~~to meet that request: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

- Approve curtailment requests to the schedules as submitted
- Implement alternative actions

~~C. Measures~~

~~**M1.** The Reliability Coordinator shall~~ **M2.** Each Balancing Authority receiving an approved request for unscheduled flow transmission relief on a Qualified Path per Requirement R1, will have evidence that it ~~approved or denied~~performed the ~~request within five minutes of receiving a request for relief,~~actions allowed in ~~accordance with Requirement R1. Evidence may include, but is not limited to, documentation of either an active or passive approval.~~

~~Each Balancing Authority shall have evidence that it provided the Relief~~ Requirement ~~through Contributing Schedules curtailments, alternative actions, or a combination that collectively meets the Relief Requirement as directed in Requirement R.2.~~R2, to meet that request.

C. ~~D.~~ Compliance

1. Compliance Monitoring Process~~:~~

1.1. Compliance Enforcement Authority:

- ~~Regional Entity~~
- ~~If the Responsible Entity works for the Regional Entity, then the Regional Entity will establish an agreement with the ERO or another entity approved by the ERO and FERC (i.e., another Regional Entity) to be responsible for compliance enforcement.~~

~~If the Responsible Entity is also a Regional Entity, the ERO or a Regional Entity approved by the ERO and FERC or other applicable governmental authorities shall serve as the~~ 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~~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 ~~complaint~~compliant for the full ~~-~~-time period since the last audit.

~~Each Balancing Authority and Reliability Coordinator~~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 Balancing Authority and~~ Each Reliability Coordinator and each Balancing Authority shall ~~retain~~keep data or evidence to show compliance with Requirements R1 and R2, for three calendar years or for the duration of any Compliance Enforcement Authority investigation~~;~~, whichever is longer.
- If ~~a Balancing Authority or~~ the Reliability Coordinator or Balancing Authority is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the duration specified above, whichever is longer.

1.3. Compliance Monitoring and Enforcement Program

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

Violation Severity Levels

	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL

~~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:~~

~~Compliance shall be determined by a single event, per path, per calendar month (at a minimum) provided at least one event occurs in that month.~~

~~R1~~	Real Time Operations	Medium	Not Applicable	Not Applicable	Not Applicable	There shall be a Severe level of non-compliance if there is one instance during a calendar month in which the

						Reliability Coordinator approved (actively or passively) or denied a request for unscheduled flow transmission relief on a Qualified Path, greater than five minutes after receipt that request.
R2	Real Time Operations	Medium	There shall be a Lower Level of non-compliance if there is less than 100% relief requirement provided but greater than or equal to 90% relief requirement provided or the relief requirement was less than 5 MW and was not fully provided.	There shall be a Moderate Level of non-compliance if there is less than 90% relief requirement provided but greater than or equal to 75% relief requirement provided.	There shall be a High Level of non-compliance if there is less than 75% relief requirement provided but greater than or equal to 60% relief requirement provided.	There shall be a Severe Level of non-compliance if there is less than 60% relief requirement provided.

D. Regional Variances

None.

E. Associated Documents

Western Interconnection Unscheduled Flow Mitigation Plan, (WIUFMP)

Version History

Version	Date	Action	Change Tracking
1	April 16, 2008	Permanent Replacement Standard for IRO-STD-006-0	
1	February 10, 2009	Adopted by NERC Board of Trustees	
1	March 17, 2011	FERC Order 746 issued by FERC approving IRO-006-WECC-1 (FERC approval effective on May 24, 2011)	
1	May 2, 2012	Updated the requirements to R1. and R2. instead of R.1. and R1.2.	
1	July 1, 2011	Effective Date	No ~~change~~Change
2	February 7, 2013	Adopted by NERC Board of Trustees	
2	May 13, 2014	FERC letter order issued approving IRO-006-WECC-2 (effective July 1, 2014).	
3	TBD		Five-year review. Defined term "Qualified Transfer Path" changed to "Qualified Path" as included in the Western Interconnection Unscheduled Flow Mitigation Plan, as approved by FERC. The following defined terms were retired: 1) Qualified Transfer Path, 2) Contributing Schedule, 3) Qualified Controllable Device, 4) Relief Requirement, 5) Transfer Distribution

			Factor, and 6) Qualified Transfer Path Curtailment Event.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Unofficial Comment Form

Regional Reliability Standard | IRO-006-WECC-3

DO NOT use this form for submitting comments. Use the electronic form to submit comments on Regional Reliability Standard **IRO-006-WECC-3 Qualified Path Unscheduled Flow (USF) Relief.** The form must be submitted by **8 p.m. Eastern, Monday, January 28, 2019.** Documents and information about this project are available on the WECC's Standards Under Development page. If you have questions, contact Standards Development Manager, Chris Larson (via email) or at (404) 446-2564.

Background Information

The Western Electricity Coordinating Council (WECC) conducted a mandatory five-year review of Regional Reliability Standard IRO-006-WECC-2.

The WECC drafting team made the following changes:

- Clarified the purpose statement;
- Replaced defined term "Qualified Transfer Path" with "Qualified Path" as included in the Western Interconnection Unscheduled Flow Mitigation Plan, approved by the Federal Energy Regulatory Commission;
- Retired the following terms from the NERC Glossary of Terms Used in Reliability Standards because they are either no longer accurate or are no longer used in any standards:
    1. Qualified Transfer Path,
    2. Contributing Schedule,
    3. Qualified Controllable Device,
    4. Relief Requirement,
    5. Transfer Distribution Factor, and
    6. Qualified Transfer Path Curtailment Event.
- Conformed the standard to current drafting conventions and template.

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 Regional Reliability Standard and answer the following questions.

1. Do you agree the development of the Regional Reliability Standard 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 the Regional Reliability Standard 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 the Regional Reliability Standard 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 the Regional Reliability Standard 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 the Regional Reliability Standard 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 (WECC) | IRO-006-WECC-3
Comment Period Start Date:	12/14/2018
Comment Period End Date:	1/28/2019
Associated Ballots:	

There were 4 sets of responses, including comments from approximately 4 different people from approximately 4 companies representing 4 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree the development of the Regional Reliability Standard met the "Open" criteria as outlined above? If "No", please explain in the comment area below:

2. Do you agree the development of the Regional Reliability Standard met the "Inclusive" criteria as outlined above? If "No", please explain in the comment area below:

3. Do you agree the development of the Regional Reliability Standard met the "Balanced" criteria as outlined above? If "No", please explain in the comment area below:

4. Do you agree the development of the Regional Reliability Standard met the "Due Process" criteria as outlined above? If "No", please explain in the comment area below:

5. Do you agree the development of the Regional Reliability Standard 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 the Regional Reliability Standard met the “Open” criteria as outlined above? If “No”, please explain in the comment area below:	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1,3,5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

2. Do you agree the development of the Regional Reliability Standard met the “Inclusive” criteria as outlined above? If “No”, please explain in the comment area below:	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1,5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

3. Do you agree the development of the Regional Reliability Standard met the “Balanced” criteria as outlined above? If “No”, please explain in the comment area below:	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1,3,5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

4. Do you agree the development of the Regional Reliability Standard met the “Due Process” criteria as outlined above? If “No”, please explain in the comment area below:	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1,5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

5. Do you agree the development of the Regional Reliability Standard met the “Transparent” criteria as outlined above? If “No”, please explain in the comment area below:	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1,3,5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Exhibit F

Standard Drafting Team Roster

Drafting Team Roster

WECC-0130 IRO-006-WECC-3
Qualified Transfer Path Unscheduled Flow Relief
Five-year Review

Below please find a biographical snapshot for the members of the WECC-0130 IRO-006-WECC-3, Qualified Transfer Path Unscheduled Flow Relief, Five-year Review Drafting Team.

Name	Background
Susan Millar, Bonneville Power Administration	Ms. Millar is a Senior Policy Advisor for System Operations at the Bonneville Power Administration. Qualifications include: • Senior Policy Advisor to System Operations on regulatory issues and internal and external initiatives affecting reliable operation of the Bulk Electric System (BES); • Transmission Provider Representative to the WECC Market Interface Committee; • Subject Matter Expert on Open Access Transmission (BPA and Pro-forma) Tariff, including Attachment J concerning Procedures for Parallel Flows; • Active participant in Task Force discussions developing Peak Reliability Enhanced Curtailment Calculator (ECC), including Phase 2, transition from webSAS to webIntegrity implementing the Unscheduled Flow Mitigation Plan (UFMP); and Phase 4, regarding the expansion of ECC tool application to multiple elements/facilities in the Western Interconnection greater than the UFMP Qualified Paths; and • Actively monitoring the entry of new Reliability Coordinator candidates in the Western Interconnection.
Jim Price, California Independent System Operator	Mr. Price is a Senior Advisor in Market Quality and Renewable Integration at the California Independent System Operator (CAISO). Qualifications include: • Bachelor of Science in Engineering and Applied Science from the California Institute of Technology;

	• Master of Science and a Doctor of Philosophy degree in Civil Engineering from Stanford University; • 19 years of experience at the California Public Utilities Commission; • 18 years at the CAISO in Market Operations, Market & Infrastructure Development, and Market Quality & Renewable Integration; • Member and vice chair of Peak Reliability's Enhanced Curtailment Calculator (ECC) Task Force; and • Former chair of the WECC Seams Issues Subcommittee and the Market and Seams Issues Subcommittee.
Gerardo Ugalde, Southwest Power Pool	Mr. Ugalde is a supervisor with the Southwest Power Pool (SPP) where he supervises the calculation of Available Flowgate Capability, Available Transmission Capability, and other related calculations in support of Transmission service and Flowgate capacity. His team works with neighboring systems to create policies determining what constitutes Firm versus Non-Firm, and to better coordinate congestion across the seams. His team also provides technical support to administer the Western Interconnection Unscheduled Flow Mitigation Plan for the Southwest Power Pool. Qualifications include: • Ten years of experience working for the Southwest Power Pool; • Five years of experience in Energy Management System modeling and Network application support; • Three years of experience in markets, primarily supporting congestion management and Security Constrained Economic Dispatch software; • Two years of experience in his current role; • Subject matter expert in evidence production in support of NERC MOD Standards MOD-001-1a, MOD-004-1, MOD-008-1, MOD-029-2a and MOD-030-3; and • Subject matter expert for the Seams group in which he monitors parallel loop flows on neighboring systems, and coordinates congestion management and use tools such as Market-to-Market (M2M) with the Midcontinent Independent System Operator and the IDC Transmission Loading Relief (TLR).

Kathee Downey, PacifiCorp	Ms. Downey is a Transmission Grid Operations Adviser at PacifiCorp. Qualifications include: • Continuing involvement in multiple WECC committees and associated drafting teams relating to WECC Interchange Scheduling and Accounting Sub-Committee (ISAS) and Federal Energy Regulatory Commission (FERC) Order 764; • Current representative on the WECC Operating Committee and ISAS; • Subject matter expert for NERC IRO-006-3, Reliability Coordination, and IRO-006-WECC-2, Qualified Transfer Path Unscheduled Flow Relief; and • Member of the Peak Enhanced Curtailment Calculator Task Force and an end user for the unscheduled flow tool.
Sean Erickson, Western Area Power Administration	Mr. Erickson is a Senior Power Operations Specialist at the Western Area Power Administration. Qualifications include: • Two years of experience as a WECC Reliability Coordinator (2009–2011); • Two years of experience as a WECC Reliability Coordination Operations Engineer (2007–2009); • Four years of experience as an Operations Engineer (2011–2015); • Currently serving as the Transmission Alternate on the WECC Operating Committee as well as the WECC Ballot Body representative for both WECC and NERC; • Previous member of the WECC Performance Work Group during the BAL-001 field trial evaluations; • Previous member of the Path Operator Task Force (POTF) (post-September 8, 2011, NERC/FERC findings and mitigation regarding Path Operations) and the POITF–Implementation Team for the Operational adoption of the POTF findings; and • Contributor to retiring TOP-007-WECC-1a, System Operating Limits.

20190328-3048 FERC PDF (Unofficial) 03/28/2019

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

OFFICE OF ELECTRIC RELIABILITY

North American Electric Reliability Corporation
Docket No. RD18-3-000

March 28, 2019

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
Lauren A. Perotti
Counsel for North American Electric Reliability Corporation

Reference: Petition of the North American Electric Reliability Corporation and Western Electricity Coordinating Council for Approval of Retirement of Regional Reliability Standard PRC-004-WECC-2

Dear Mr. Elstein and Ms. Perotti:

On March 9, 2018, the North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) filed a joint petition seeking approval of the retirement of regional Reliability Standard PRC-004-WECC-2 (Protection System and Remedial Action Scheme Misoperation). On February 11, 2019, NERC and WECC filed a joint supplemental petition revising the proposed retirement effective date of the regional Reliability Standard to January 1, 2021.

NERC and WECC state that continent-wide Reliability Standards have been developed since the initial development of the regional Reliability Standard, thereby making the regional Reliability Standard redundant and no longer necessary for reliability. In particular, Reliability Standard PRC-012-2 (Remedial Action Schemes), approved by the Commission in Order No. 837, contains requirements for remedial action scheme analysis.[1] Reliability Standard PRC-012-2 will become effective in the United

[1] *Remedial Action Schemes Reliability Standard*, 160 FERC ¶ 61,071 (2017).

20190328-3048 FERC PDF (Unofficial) 03/28/2019

States on January 1, 2021. According to NERC and WECC, the regional Reliability Standard may therefore be retired at that time with no adverse effect on reliability.[2]

NERC's filing was noticed on March 15, 2018, with interventions, comments and protests due on or before April 16, 2018. Southern California Edison filed a timely motion to intervene, raising no issues. NERC's supplemental filing was noticed on February 12, 2019, with interventions, comments and protests due on or before March 4, 2019. No comments were received.

NERC's uncontested filings are hereby approved pursuant to the relevant authority delegated to the Director, Office of Electric Reliability under 18 C.F.R. § 375.303 (2018), 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 (2018)

Sincerely,

Andrew Dodge, Director
Office of Electric Reliability

[2] Joint Supplemental Petition at 2.

Document Content(s)

RD18-3-000.DOCX.....1-2

20190301-3025 FERC PDF (Unofficial) 03/01/2019

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

OFFICE OF ENERGY MARKET REGULATION

In Reply Refer To:
North American Electric Reliability
Corporation
Docket No. RR19-1-000

Issued: March 1, 2109

Edwin G. Kichline
North American Electric Reliability Corporation
1325 G Street, NW, Suite 600
Washington, DC 20005

Reference: Revised Appendix 4E to the North American Electric Reliability Corporation Rules of Procedure

On October 16, 2018, North American Electric Reliability Corporation (NERC) submitted revisions to Appendix 4E, the Compliance and Certification Committee (CCC) Hearing Procedures, and Mediation Procedures, of its Rules of Procedure. NERC states that the purpose of the proposed revisions is to align the rules and procedural steps of the Hearing Procedures used in the Compliance Monitoring and Enforcement Program as per the CCC Charter.

Notice of this filing was published in the *Federal Register*, with protests and interventions due on or before November 6, 2018. 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 adverse comments were received.

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, 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. § 375.307(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

20190301-3025 FERC PDF (Unofficial) 03/01/2019

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.

Issued by: Penny S. Murrell, Director, Division of Electric Power Regulation – Central

Document Content(s)

RR19-1-000.DOCX.....1-2

20190301-3027 FERC PDF (Unofficial) 03/01/2019

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

OFFICE OF ENERGY MARKET REGULATION

In Reply Refer To:
North American Electric Reliability
Corporation
Docket No. RR19-3-000

Issued: March 1, 2019

Alexander Kaplen
North American Electric Reliability Corporation
1325 G Street, NW, Suite 600
Washington, DC 20005

Reference: Amended Compliance and Certification Committee Charter

On November 30, 2018, North American Electric Reliability Corporation (NERC) submitted proposed revisions to the Compliance and Certification Committee (CCC) Charter. Specifically, NERC states that the proposed amendments to the CCC Charter were made to reflect the dissolution of the Southwest Power Pool Regional Entity (SPP RE) by removing SPP RE from the Regional Entity sector in the CCC membership structure found in Attachment A of the CCC Charter.

Notice of this filing was issued on December 3, 2018, with protests and interventions due on or before December 21, 2018. 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 adverse comments were received.

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, 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. § 375.307(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

20190301-3027 FERC PDF (Unofficial) 03/01/2019

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.

Issued by: Penny S. Murrell, Director, Division of Electric Power Regulation – Central

Document Content(s)

RR19-3-000.DOCX.....1-2

20190301-3026 FERC PDF (Unofficial) 03/01/2019

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

OFFICE OF ENERGY MARKET REGULATION

In Reply Refer To:
North American Electric Reliability
Corporation
Docket No. RR19-2-000

Issued: March 1, 2019

Lauren A. Perotti
North American Electric Reliability Corporation
1325 G Street, NW, Suite 600
Washington, DC 20005

Reference: Revised Standard Processes Manual

On November 19, 2018, North American Electric Reliability Corporation (NERC) submitted proposed amendments to Appendix 3A of the NERC Rules of Procedure, the Standard Processes Manual. NERC states that the proposed amendments (1) enhance processes for field tests to support standards development and for posting supporting technical documents; (2) improve processes for appeals and interpretations; (3) provide language to clarify existing standard processes; and (4) streamline language, correct capitalization or titles of documents, and make other necessary updates.

Notice of this filing was published in the *Federal Register*, with protests and interventions due on or before December 10, 2018. 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 adverse comments were received.

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, 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. § 375.307(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

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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.

Issued by: Penny S. Murrell, Director, Division of Electric Power Regulation – Central

Document Content(s)

RR19-2-000.DOCX.....1-2

20190430-3108 FERC PDF (Unofficial) 04/30/2019

167 FERC ¶ 61,095
FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

April 30, 2019

In Reply Refer To:
North American Electric Reliability Corporation
Florida Reliability Coordinating Council, Inc.
SERC Reliability Corporation
Docket No. RR19-4-000

North American Electric Reliability Corporation
3353 Peachtree Road, NE
Suite 600, North Tower
Atlanta, GA 30326

Florida Reliability Coordinating Council
3000 Bayport Drive
Suite 600
Tampa, FL 33607

SERC Reliability Corporation
3701 Arco Corporate Drive
Suite 300
Charlotte, NC 28273

Attention: Nina H. Jenkins-Johnston, Morvarid M. Jones, and Holly A. Hawkins

Dear Ms. Jenkins-Johnston, Ms. Jones, and Ms. Hawkins:

1. On February, 27, 2019, the North American Electric Reliability Corporation (NERC), Florida Reliability Coordinating Council, Inc. (FRCC), and SERC Reliability Corporation (SERC) (collectively, Petitioners) filed a joint petition requesting certain Commission approvals in connection with the dissolution of FRCC as a Regional Entity

20190430-3108 FERC PDF (Unofficial) 04/30/2019

and the transfer of registered entities within the FRCC footprint to SERC (Joint Petition).[1] In this order, we grant the requested approvals, as discussed below.

2. In their Joint Petition, Petitioners state that NERC and FRCC mutually agreed in October 2018 to terminate the responsibilities of FRCC as a Regional Entity.[2] Petitioners explain that the decision to dissolve FRCC as a Regional Entity stemmed from a review of FRCC's governance structure in response to NERC's determination that Regional Entities should be separate corporate entities from NERC registered entities. Petitioners explain that NERC and FRCC entered into a Termination Agreement setting forth each party's obligations in support of the termination of the Regional Delegation Agreement between NERC and FRCC and the transition of FRCC's delegated authority in a manner that maintains reliability and enhances the efficiency of the ERO Enterprise.[3]

3. Petitioners state that, under the Termination Agreement, NERC would be responsible for, *inter alia*, issuing a determination specifying that, by July 1, 2019, SERC shall be the transferee Regional Entity for all registered entities in the FRCC region. They state that FRCC would be responsible for transferring relevant files and documents pertaining to delegation-related activities to the transferee Regional Entity and for submitting certain financial information to NERC following termination of its Regional Entity activities.[4] Petitioners request that FRCC cease to exist as a Regional Entity and complete the wind down of its business on August 31, 2019.

4. Petitioners propose changes to the existing Regional Delegation Agreement between NERC and SERC to reflect the new, regional boundaries for SERC due to the transfers of FRCC registered entities. Petitioners state that the proposed transfers of registered entities are consistent with the Commission's general guidance regarding changes in a Regional Entity's boundary, in which the Commission has noted that such changes "should be carefully considered and should serve to improve the effectiveness or

[1] FRCC's governance structure includes a NERC Regional Entity division and a Member Services division. Petitioners seek approval to dissolve FRCC as a Regional Entity, but not FRCC Member Services. FRCC is a registered entity registered as a reliability coordinator and planning authority, and these functions are not affected by this filing.

[2] NERC filed an errata to its original submission on March 1, 2019, to correct Attachment 4 of the Joint Petition with a correct list of registered entities that NERC proposed to transfer from FRCC to SERC.

[3] Joint Petition at 4-5.

[4] *Id.* at 7, 9-10.

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efficiency of the Regional Entity's and NERC's administration of reliability, and should not merely benefit an individual registered entity."[5] Petitioners indicate that NERC relied upon the criteria in section 1208 of its Rules of Procedure in developing the revised boundaries for SERC.

5. Petitioners also seek approval of amendments to the SERC bylaws related to SERC's executive committee representatives.[6] Among other things, Petitioners propose to increase the number of representatives on SERC's board executive committee (BEC) from 12 to 15 to ensure that FRCC entities will be able to engage fully in SERC board of directors activities.[7] Petitioners also propose to amend the SERC bylaws to divide the BEC members into two groups and introduce staggered, two-year terms (i.e., alternating terms for Group 1 and Group 2) to avoid having the entire BEC membership turn over at the same time.[8]

6. Petitioners request the Commission's approval to provide for the funding of transitional and wind-down costs.[9] As a first step to fund wind-down costs, Petitioners state that they will use FRCC's expected available cash as of July 1, 2019. Petitioners indicate that SERC expects an increase in costs to integrate the transferred FRCC entities for 2019 and beyond, including the addition of 17 to 21 full-time equivalent staff members. Petitioners request that SERC apply the FRCC third and fourth quarter assessments in 2019 toward the costs of assuming FRCC's delegated authority.[10]

7. In addition, Petitioners request approval of a special assessment of up to $630,000 to assist with wind-down costs. Petitioners state that additional assessment funding may be needed if, during the course of the fiscal year, FRCC determines it does not or will not have sufficient funds to carry out its delegated functions and related activities.[11] Petitioners assert that they satisfy the "unforeseen and extraordinary circumstances"

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[5] *Id.* at 8 (quoting *North American Electric Reliability Corp.*, 133 FERC ¶ 61,061, at P 72 (2010)).

[6] *Id.* at 4.

[7] *Id.* at 15-16.

[8] *Id.* at 16.

[9] *Id.* at 4.

[10] *Id.* at 13.

[11] *Id.* at 9-10.

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criteria established in Order No. 672 for requesting emergency funding.[12] Petitioners state that the circumstance warranting this request for a special assessment was the October 30, 2018 FRCC board of trustees vote to wind down FRCC as a Regional Entity, which accelerated the maturation of FRCC's obligation to make retention agreement payments to 14 FRCC staff and nine key shared corporate staff upon dissolution of FRCC.[13]

8. Lastly, to the extent required, Petitioners request the Commission's approval to deviate from the application of penalty monies as specified in section 1107 of the NERC Rules of Procedure,[14] to permit the use of penalty payments for FRCC wind-down and SERC transition costs. As part of this request, Petitioners state that penalty monies processed and submitted to NERC between July 1, 2018 and July 1, 2019 would apply towards wind-down costs. Petitioners state that penalty monies processed and submitted between July 1, 2019, and December 31, 2019, or not otherwise applied towards wind-down costs, would be reimbursed to FRCC entities on a *pro rata* basis.[15]

9. Notice of Petitioners' February 27, 2019 filing was published in the *Federal Register*, 84 Fed. Reg. 8328 (2019), with interventions and protests due on or before March 20, 2019. Notice of the Errata to the Petitioners' February 27, 2019 filing was

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[12] *See Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, 114 FERC ¶ 61,104, at P 37, *order on reh'g*, Order No. 672-A, 114 FERC ¶ 61,328 (2006) and 18 C.F.R. § 39.4(d) (2018) ("On a demonstration of unforeseen and extraordinary circumstances requiring additional funds prior to the next [ERO] fiscal year, the [ERO] may file with the Commission for authorization to collect a special assessment.").

[13] Joint Petition at 10-11, 13.

[14] Section 1107.2 of the NERC Rules of Procedure provides that:

> All funds from financial Penalties assessed in the United States received by the entity initiating the compliance monitoring and enforcement process shall be applied as a general offset to the entity's budget requirement for the subsequent fiscal year, if received by July 1, or for the second subsequent fiscal year, if received on or after July 1. Funds from financial Penalties shall not be directly applied to any program maintained by the entity conducting the compliance monitoring and enforcement process.

[15] Joint Petition at 5, 11-12.

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published in the *Federal Register*, 84 Fed. Reg. 9320 (2019), with interventions and protests due on or before March 20, 2019. None were filed.

10. We grant the requested approvals needed for the dissolution of FRCC as a Regional Entity by August 31, 2019 and the transfer of its registered entities to SERC by July 1, 2019. We find that Petitioners have demonstrated that the proposal, including changes to the Regional Delegation Agreement between NERC and SERC to reflect the transfers of all FRCC registered entities to SERC, will "promote effective and efficient administration of bulk-power system reliability," in accordance with FPA section 215(e)(4).[16]

11. We find NERC's approach of transferring to SERC all FRCC registered entities is consistent with the criteria in section 1208 of NERC's Rules of Procedure governing individual requests to change a Regional Entity boundary, and with applicable Commission precedent. The Commission has previously found that "it is clear that the [s]ection 1208 criteria are designed to promote effective and efficient administration of Bulk-Power System reliability."[17] When approving the dissolution of the Southwest Power Pool Regional Entity and related registered entity transfers to Midwest Reliability Organization and SERC, the Commission determined that applying the section 1208 criteria was appropriate.[18] Therefore, we find that the use of the section 1208 criteria is also appropriate here in evaluating the transfer of FRCC registered entities to SERC.

12. Accordingly, we approve the Joint Petition's proposal to terminate the Regional Delegation Agreement between NERC and FRCC in accordance with the terms of the Termination Agreement, and to transfer the registered entities within FRCC to SERC. We also approve the proposed revisions to the Regional Delegation Agreement between NERC and SERC to reflect the change in regional boundaries due to the transfer of FRCC registered entities to SERC. Further, we find that Petitioners' proposed amendments to SERC's bylaws are appropriate to facilitate the transfer of FRCC registered entities to SERC.

13. In addition, we approve Petitioners' requests related to the funding of transitional and wind-down costs. In particular, we approve NERC's request to deviate from the requirements of section 1107 of the NERC Rules of Procedure to allow FRCC to apply

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[16] *See* 16 U.S.C. § 824o(e)(4) (2012) (the ERO may enter into an agreement to delegate authority to a regional entity if, *inter alia*, … "the agreement promotes effective and efficient administration of bulk-power system reliability").

[17] *North American Electric Reliability Corp.*, 134 FERC ¶ 61,179, at P 9 (2011).

[18] *North American Electric Reliability Corp.*, 163 FERC ¶ 61,094, at P 17 (2018).

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certain penalty funds received on or after July 1, 2018 for its wind-down activities, and to allow SERC to apply penalty monies toward the costs of assuming delegated authority over FRCC's registered entities.[19] We find that NERC's request is appropriate, in light of the dissolution of FRCC as a Regional Entity, and is consistent with section 1107.4 of the NERC Rules of Procedure, which allows Regional Entities to obtain a waiver of this requirement, if approved.[20] We also approve FRCC's request to make a special assessment of up to $630,000. We find that FRCC's request is appropriate, in light of the dissolution of its role as a Regional Entity and its contractual obligations to its employees, resulting in what we find to be an "unforeseen and extraordinary circumstance."[21]

By direction of the Commission.

Kimberly D. Bose,
Secretary.

[19] Joint Petition at 10-12.

[20] Section 1107.4 of the NERC Rules of Procedure provides that "[e]xceptions or alternatives to the foregoing provisions will be allowed if approved by NERC and by [the Commission]."

[21] *See* 18 C.F.R. § 39.4(d).

Document Content(s)

RR19-4-000.DOCX.....1-6

20190418-3038 FERC PDF (Unofficial) 04/18/2019

167 FERC ¶ 61,055

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 40

[Docket No. RM18-20-000]

Critical Infrastructure Protection Reliability Standard CIP-012-1 – Cyber Security – Communications between Control Centers

(April 18, 2019)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission (Commission) proposes to approve Reliability Standard CIP-012-1 (Cyber Security – Communications between Control Centers). The North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization, submitted the proposed Reliability Standard for Commission approval in response to a Commission directive. In addition, the Commission proposes to direct that NERC develop certain modifications to Reliability Standard CIP-012-1 to require protections regarding the availability of communication links and data communicated between bulk electric system control centers and, further, to clarify the types of data that must be protected.

DATES: Comments are due **[INSERT DATE 60 days after publication in the FEDERAL REGISTER].**

20190418-3038 FERC PDF (Unofficial) 04/18/2019

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:

Vincent Le (Technical Information)
Office of Electric Reliability
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426
(202) 502-6204
vincent.le@ferc.gov

Kevin Ryan (Legal Information)
Office of the General Counsel
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426
(202) 502-6840
kevin.ryan@ferc.gov

SUPPLEMENTARY INFORMATION:

20190418-3038 FERC PDF (Unofficial) 04/18/2019

167 FERC ¶ 61,055
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Critical Infrastructure Protection Reliability Standard CIP-012-1 – Cyber Security – Communications between Control Centers

Docket No. RM18-20-000

NOTICE OF PROPOSED RULEMAKING

(April 18, 2019)

1. Pursuant to section 215(d)(2) of the Federal Power Act (FPA),[1] the Commission proposes to approve Reliability Standard CIP-012-1 (Cyber Security – Communications between Control Centers). The North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization (ERO), submitted the proposed Reliability Standard for Commission approval in response to a Commission directive in Order No. 822.[2] Specifically, pursuant to section 215(d)(5) of the FPA, the Commission directed that NERC develop modifications to require responsible entities to implement controls to protect, at a minimum, communications links and sensitive bulk electric system data communicated between bulk electric system Control Centers "in a

[1] 16 U.S.C. 824o(d)(2) (2012).

[2] *Revised Critical Infrastructure Protection Reliability Standards*, Order No. 822, 154 FERC ¶ 61,037, at P 53, *order denying reh'g*, Order No. 822-A, 156 FERC ¶ 61,052 (2016).

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manner that is appropriately tailored to address the risks posed to the bulk electric system by the assets being protected (i.e., high, medium, or low impact)."[3]

2. Proposed Reliability Standard CIP-012-1 is intended to augment the currently-effective Critical Infrastructure Protection (CIP) Reliability Standards to mitigate cybersecurity risks associated with communications between bulk electric system Control Centers.[4] Specifically, proposed Reliability Standard CIP-012-1 supports situational awareness and reliable bulk electric system operations by requiring responsible entities to protect the confidentiality and integrity of Real-time Assessment and Real-time monitoring data transmitted between bulk electric system Control Centers.[5] Accordingly, the Commission proposes to approve proposed Reliability Standard CIP-012-1 based on a determination that the standard is largely responsive to the Commission's directive in Order No. 822 and improves the cybersecurity posture of applicable entities.

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[3] 16 U.S.C. 824o(d)(5); Order No. 822, 154 FERC ¶ 61,037 at P 53.

[4] BES Cyber System is defined as "[o]ne or more BES Cyber Assets logically grouped by a responsible entity to perform one or more reliability tasks for a functional entity." Glossary of Terms Used in NERC Reliability Standards (NERC Glossary), http://www.nerc.com/files/glossary_of_terms.pdf. The acronym BES refers to the bulk electric system.

[5] The NERC Glossary defines Real-time Assessment as "An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)" NERC Glossary of Terms Used in NERC Reliability Standards (July 3, 2018).

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3. However, we are concerned that there still may be certain cyber security risks associated with the protection of communications links and sensitive bulk electric system data communicated between bulk electric system Control Centers that are not adequately addressed in NERC's proposal. First, proposed Reliability Standard CIP-012-1 does not require protections regarding the availability of communication links and data communicated between bulk electric system Control Centers as directed in Order No. 822.[6] As discussed below, at this time, we are not persuaded by NERC's explanation that certain currently-effective CIP Reliability Standards address the issue of availability. Second, proposed Reliability Standard CIP-012-1 does not adequately identify the types of data covered by its requirements, due to, among other things, the fact that the term "Real-time monitoring" is not defined in the proposed Reliability Standard or the NERC Glossary. Clarification of the types of covered data is warranted.

4. To address these issues, pursuant to section 215(d)(5) of the FPA, the Commission proposes to direct that NERC develop modifications to the CIP Reliability Standards to: (1) require protections regarding the availability of communication links and data communicated between bulk electric system Control Centers; and (2) clearly identify the types of data that must be protected.

[6] Order No. 822, 154 FERC ¶ 61,037 at P 54.

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I. Background

A. Section 215 and Mandatory Reliability Standards

5. Section 215 of the FPA requires a Commission-certified ERO to develop mandatory and enforceable Reliability Standards, subject to Commission review and approval. Reliability Standards may be enforced by the ERO, subject to Commission oversight, or by the Commission independently.[7] Pursuant to section 215 of the FPA, the Commission established a process to select and certify an ERO,[8] and subsequently certified NERC.[9]

B. Order No. 822

6. In Order No. 822, the Commission approved seven modified CIP Reliability Standards and directed NERC to develop additional modifications to the CIP Reliability Standards.[10] Specifically, the Commission directed NERC to, among other things, develop modifications to the CIP Reliability Standards to require responsible entities to implement controls to protect, at a minimum, communications links and sensitive bulk

[7] 16 U.S.C. 824o(e).

[8] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, 114 FERC ¶ 61,104, *order on reh'g*, Order No. 672-A, 114 FERC ¶ 61,328 (2006).

[9] *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).

[10] Order No. 822, 154 FERC ¶ 61,037 at PP 1, 3.

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electric system data communicated between bulk electric system Control Centers "in a manner that is appropriately tailored to address the risks posed to the bulk electric system by the assets being protected (i.e., high, medium, or low impact)."[11] The Commission observed that NERC, as well as other commenters in that proceeding, "recognize that inter-Control Center communications play a critical role in maintaining bulk electric system reliability by . . . helping to maintain situational awareness and support reliable operations through timely and accurate communication between Control Centers."[12]

7. The Commission explained that Control Centers associated with responsible entities, including reliability coordinators, balancing authorities, and transmission operators, must be capable of receiving and storing a variety of bulk electric system data from their interconnected entities in order to adequately perform their reliability functions. The Commission, therefore, determined that "additional measures to protect both the integrity and availability of sensitive bulk electric system data are warranted."[13] The Commission also recognized that the data managed by responsible entities has different attributes that may require different information protection controls, and the Commission stated that NERC should consider the different attributes of bulk electric system data as it assesses appropriate information protection controls. The Commission

[11] *Id.* P 53.

[12] *Id.* P 54 (citing NERC Comments at 20).

[13] *Id.* P 54.

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concluded that NERC "should have flexibility in the manner in which it addresses the Commission's directive."[14]

8. In Order No. 822, the Commission found to be reasonable the following principles outlined in NERC's comments in that Commission proceeding regarding protections for communication links and sensitive bulk electric system data communicated between bulk electric system Control Centers:

> (1) should not have an adverse effect on reliability, including the recognition of instances where the introduction of latency could have negative results; (2) should account for the risk levels of assets and information being protected, and require protections that are commensurate with the risks presented; and (3) should be results-based in order to provide flexibility to account for the range of technologies and entities involved in bulk electric system communications.[15]

In addition, the Commission cautioned that "not all communication network components and data pose the same risk to bulk electric system reliability and may not require the same level of protection."[16] Therefore, the Commission determined that NERC should develop controls that reflect the risk being addressed in a reasonable manner.

C. NERC Petition and Proposed Reliability Standard CIP-012-1

9. On September 18, 2018, NERC submitted for Commission approval proposed Reliability Standard CIP-012-1 and the associated violation risk factors and violation

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[14] *Id.* P 55.

[15] *Id.*

[16] *Id.* P 56.

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severity levels, implementation plan, and effective date.[17] NERC states that the purpose of the proposed Reliability Standard is to help maintain situational awareness and reliable bulk electric system operations by protecting the confidentiality and integrity of Real-time Assessment and Real-time monitoring data transmitted between Control Centers.

10. NERC explains that, although the Commission directed modifications to Reliability Standard CIP-006-6, the standard drafting team determined to address the Commission's communications directive by developing a new Reliability Standard. According to NERC, the differences in the scope and applicability between the existing requirements of Reliability Standard CIP-006-1 and the Commission's directive necessitated the development of a new Reliability Standard. Specifically, NERC notes that while Reliability Standard CIP-006-6, Requirement R1, Part 1.10 mandates protections for nonprogrammable communication components outside a Physical Security Perimeter (PSP) but inside the same Electronic Security Perimeter (ESP) for certain Cyber Assets, proposed Reliability Standard CIP-012-1 "requires protections for communications between Control Centers that transmit certain data regardless of the location of Cyber Assets inside or outside a PSP or ESP."[18] In addition, NERC explains that unlike Reliability Standard CIP-006-6, which applies to high and medium impact

[17] Proposed Reliability Standard CIP-012-1 is not attached to this notice of proposed rulemaking (NOPR). The proposed Reliability Standards are available on the Commission's eLibrary document retrieval system in Docket No. RM18-20-000 and on the NERC website, www.nerc.com.

[18] NERC Petition at 9.

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BES Cyber Assets at Control Centers, proposed Reliability Standard CIP-012-1 applies to assets associated with communications between certain Control Centers.

11. NERC states that proposed Reliability Standard CIP-012-1 "requires Responsible Entities to develop and implement a plan to address the risks posed by unauthorized disclosure (confidentiality) and unauthorized modification (integrity) of Real-time Assessment and Real-time monitoring data while being transmitted between applicable Control Centers."[19] According to NERC, the required plan must include the following: (1) identification of security protections; (2) identification of where the protections are applied; and (3) identification of the responsibilities of each entity in case a Control Center is owned or operated by different responsible entities.[20]

12. NERC posits that, consistent with the Commission's directive in Order No. 822, the risks posed by different types of BES Control Centers and the associated data communicated between the Control Centers were considered by the standard drafting team to determine its appropriate scope and applicability.[21] With regard to functional entities and facilities, NERC states that proposed Reliability Standard CIP-012-1 applies to balancing authorities, generator operators, reliability coordinators, transmission operators and transmission owners that own or operate a Control Center. NERC explains that proposed Reliability Standard CIP-012-1 applies to all Control Centers, with one

[19] *Id.* at 10.

[20] *Id.* at 3.

[21] *Id.*

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exemption discussed below, "regardless of the impact level of BES Cyber Systems located at or associated with those control centers."[22] In that regard, NERC explains that the standard drafting team determined that the sensitivity of data communicated between Control Centers "is not necessarily dependent on the impact level of the BES Cyber Systems located at or associated with the Control Centers."[23] NERC states that the standard drafting team, instead, focused on the types of Real-time data a Control Center will communicate and whether the compromise of that data would pose a high risk to bulk electric system reliability.

13. As noted above, the types of data within the scope of proposed Reliability Standard CIP-012-1 consists of Real-time Assessment and Real-time monitoring data exchanged between Control Centers. NERC states that it is critical that this information is accurate since responsible entities operate and monitor the bulk electric system based on this Real-time information. However, NERC points out that proposed Reliability Standard CIP-012-1 exempts Control Centers "that transmit[] to another Control Center Real-time Assessment or Real-time monitoring data pertaining only to the generation resource of transmission station or substation co-located with the transmitting Control Center."[24] NERC explains that proposed Reliability Standard CIP-012-1 "excludes other data typically transferred between Control Centers, such as Operational Planning

[22] *Id.* at 10.

[23] *Id.*

[24] *Id.* at 11.

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Analysis data, that is not used by the Reliability Coordinator, Balancing Authority, and Transmission Operator in Real-time."[25] According to NERC, while Operational Planning Analysis data provides information for next-day operations, "entities adjust their operating actions during the current day based on the data from Real-time Assessments and Real-time monitoring."[26] NERC contends that if there is a risk that Operational Planning Analysis data has been compromised, the responsible entity has the opportunity to verify the data prior to any impact on Real-time operations. Therefore, NERC concludes that while "an Operational Planning Analysis factors into how an entity operates, there is less of a risk that an entity would act on compromised data from an Operational Planning Analysis given it will base its operating actions on Real-time inputs."[27]

14. NERC also indicates that data at rest and oral communications fall outside the scope of proposed Reliability Standard CIP-012-1. Regarding data at rest, NERC states that the standard drafting team determined that since data at rest resides within BES Cyber Systems, it is already protected by the controls mandated by Reliability Standards CIP-003-6 through CIP-011-2. According to NERC, oral communications are out of scope of proposed Reliability Standard CIP-012-1 "because operators have the ability to terminate the call and initiate a new one via trusted means if they suspect a problem with,

[25] *Id.* at 12.

[26] *Id.*

[27] *Id.* at 13.

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or compromise of, the communication channel."[28] NERC notes that Reliability Standard COM-001-3 requires reliability coordinators, balancing authorities, and transmission operators to have alternative interpersonal communication capability, which could be used if there is a suspected compromise of oral communication on one channel.

II. Discussion

15. Pursuant to section 215(d)(2) of the FPA, the Commission proposes to approve proposed Reliability Standard CIP-012-1 as just, reasonable, not unduly discriminatory or preferential, and in the public interest. The proposed Reliability Standard will enhance existing protections for bulk electric system reliability by augmenting the currently-effective CIP Reliability Standards to mitigate cybersecurity risks associated with communications between bulk electric system Control Centers. Specifically, consistent with the Commission's directive in Order No. 822, proposed Reliability Standard CIP-012-1 supports situational awareness and reliable bulk electric system operations by requiring responsible entities to protect the confidentiality and integrity of Real-time Assessment and Real-time monitoring data transmitted between bulk electric system Control Centers.

16. While the Commission proposes to approve Reliability Standard CIP-012-1, certain cyber security risks associated with communications between bulk electric system Control Centers may not be fully addressed even with the implementation of the proposed Reliability Standard. As discussed below, the Commission is concerned that a

[28] *Id.* at 14.

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significant cyber security risk associated with the protection of communications links and sensitive bulk electric system data communicated between bulk electric system Control Centers may persist because: (1) the CIP Reliability Standards do not address the availability of communication links and data communicated between bulk electric system Control Centers; and (2) proposed Reliability Standard CIP-012-1 does not adequately identify the types of data covered by its Requirements, due to, among other things, the fact that the term "Real-time monitoring" is not defined.

17. To address these gaps, the Commission seeks comment on proposals to direct NERC, pursuant to section 215(d)(5) of the FPA, to develop modifications to the CIP Reliability Standards to: (1) require protections regarding the availability of communication links and data communicated between bulk electric system Control Centers; and (2) clearly identify the types of data that must be protected.

18. Below, we discuss the following issues: (A) availability of bulk electric system communication links and data; and (B) scope of bulk electric system data that must be protected.

A. Availability of Bulk Electric System Communication Links and Data

Order No. 822

19. In Order No. 822, the Commission directed that NERC "should identify the scope of sensitive bulk electric system data that must be protected and specify how the confidentiality, integrity, and availability of each type of bulk electric system data should

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be protected while it is being transmitted or at rest."[29] In addition, the Commission clarified that "the directed modification should encompass communication links and data for intra-Control Center and inter-Control Center communications."[30]

20. Specifically, the Commission explained that bulk electric system Control Centers must be capable of exchanging and storing sensitive bulk electric system data from interconnected entities in order for responsible entities to adequately perform their reliability functions. The Commission determined "that additional measures to protect both the integrity and *availability* of sensitive bulk electric system data are warranted."[31] The Commission explained that protecting the availability of sensitive bulk electric system data involves ensuring that the data required for bulk electric system operations is available when needed. The Commission responded to concerns that the risks posed by bulk electric system communication networks do not justify the cost of implementing controls by explaining that communications between Control Centers are fundamental to reliable bulk electric system operations. The Commission, however, also recognized that "not all communication network components and data pose the same risk to bulk electric system reliability and may not require the same level of protection."[32] The Commission therefore determined that it expected NERC to develop controls that reflect the associated risk and that can be implemented in a reasonable manner.

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[29] Order No. 822, 154 FERC ¶ 61,037 at P 56.

[30] *Id.* P 58.

[31] *Id.* P 54 (emphasis added).

[32] *Id.* P 56.

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NERC Petition

21. NERC states that proposed Reliability Standard CIP-012-1, Requirement R1 mandates that:

> each Responsible Entity develop a plan to mitigate the risks posed by unauthorized disclosure and unauthorized modification of Real-time Assessment and Real-time monitoring data while being transmitted between and applicable Control Centers.[33]

NERC acknowledges that Order No. 822 directed that "NERC should develop measures to protect the confidentiality, integrity, and availability of sensitive [bulk electric system] data."[34] NERC states, however, that while proposed Reliability Standard CIP-012-1 requires protections for the confidentiality (i.e., unauthorized disclosure) and integrity (i.e., unauthorized modification) of Real-time Assessment and Real-time monitoring data, the availability of that data is addressed in currently-effective Reliability Standards.

22. Specifically, NERC maintains that Reliability Standard IRO-002-5 "requires redundant and diversely routed data exchange infrastructure within the Reliability Coordinator's primary Control Center in order to exchange Real-time data used in Real-time monitoring and Real-time Assessments with Balancing Authorities, Transmission Operators, and other entities the Reliability Coordinator deems necessary."[35] Similarly, NERC states that Reliability Standard TOP-001-4 "requires Balancing Authorities and

[33] Petition at 15-16.

[34] *Id.* at 17.

[35] *Id.* at 18.

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Transmission Operators to have redundant and diversely routed data exchange infrastructure to exchange Real-time data."[36] According to NERC, the "redundancy of data exchange infrastructure helps to ensure the availability of critical Real-time data for Control Centers."[37] Further, NERC notes that Reliability Standards IRO-010-2 and TOP-003-3 require reliability coordinators, transmission operators, and balancing authorities to use a mutually agreeable security protocol for exchange of Real-time data. NERC contends that, by agreeing on security protocols, entities communicate directly with the appropriate entities rather than having to translate different protocols, which helps to ensure the availability of Real-time data.

Discussion

23. We are not persuaded by the explanation in NERC's petition that currently-effective CIP Reliability Standard requirements address the availability directive in Order No. 822. Sensitive bulk electric system data generally includes monitoring, operational, and system planning data. Ensuring timely and reliable access to and use of this information is essential to the reliable operation of the bulk electric system. As the Commission noted in Order No. 822, bulk electric system Control Centers "must be capable of receiving and storing a variety of sensitive bulk electric system data from interconnected entities."[38] In particular, the Commission stated that additional

[36] *Id.*

[37] *Id.*

[38] Order No. 822, 154 FERC ¶ 61,037 at P 54.

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protections to address the availability of sensitive bulk electric system data are warranted.[39]

24. We are not persuaded that the currently-effective Reliability Standards cited in NERC's petition require responsible entities to protect the availability of sensitive bulk electric system data in a manner consistent with the directives in Order No. 822. For instance, Reliability Standards IRO-002-5 and TOP-001-4 require responsible entities to have redundant and diversely routed data exchange infrastructure *within* the Control Center environment, but do not pertain to communications *between* individual Control Centers, which was the subject of the Commission's directive in Order No. 822. Similarly, Reliability Standards IRO-010-2 and TOP-003-3 require responsible entities to have mutually agreeable security protocols for exchange of Real-time data, which may have the effect of contributing to greater availability; however, these requirements do not create an obligation, as directed in Order No. 822, to protect the availability of those communication capabilities and associated data by applying appropriate security controls. Creating an *obligation* to protect availability, while affording flexibility in terms of what data is protected and how, is distinct from relying on currently-effective Reliability Standards whose *effect* may be to improve availability.

25. Bonneville Power Administration (BPA) and CenterPoint Energy Houston Electric addressed this distinction during the standards development process when they responded to the standard drafting team's assertion that the availability directive is adequately

[39] *Id.*

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addressed by currently-effective CIP Reliability Standards. BPA explained that "[w]hile the requirements of TOP-001-4 and IRO-002-5 (redundant and diverse routing of data) can be used to achieve increased Availability, it can also be achieved through other equally effective methods . . . [and] [t]herefore, 'availability' is not adequately addressed by TOP-001-4 and IRO-002-5 and limits entities' options to address availability by other methods more appropriate to their systems."[40] CenterPoint stated that, "TOP-001-4 and IRO-002-5 do not ensure availability or communication of data between inter-entity and intra-entity Control Centers, but only the redundancy of infrastructure internal to the requesting entity's primary Control Center."[41]

26. Not addressing the availability of covered communication links and data could lead to unreliable operations resulting from the inability to communicate data between Control Centers. While NERC contends that currently-effective CIP Reliability Standards adequately protect the availability of sensitive bulk electric system data, there is no obligation on responsible entities to affirmatively protect the availability of such data. Moreover, while the Commission in Order No. 822 allowed NERC flexibility in what data is protected and how, NERC has not addressed the directive to protect the availability of sensitive bulk electric system data.

27. Accordingly, pursuant to section 215(d)(5) of the FPA, the Commission proposes to direct that NERC develop modifications to the CIP Reliability Standards to require

[40] NERC Petition at page 273 of pdf.

[41] *Id.* at page 274 of pdf.

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protections regarding the availability of communication links and data communicated between bulk electric system Control Centers. We seek comment on this proposal.

B. Scope of Bulk Electric System Data that Must Be Protected

Order No. 822

28. In Order No. 822, the Commission stated that NERC "should identify the scope of sensitive bulk electric system data that must be protected and specify how the confidentiality, integrity, and availability of each type of bulk electric system data should be protected while it is being transmitted or at rest."[42] In addition, the Commission clarified that "the directed modification should encompass communication links and data for intra-Control Center and inter-Control Center communications."[43]

NERC Petition

29. NERC states that proposed Reliability Standard CIP-012-1 applies to Real-time Assessment and Real-time monitoring data due to the critical nature of the information. NERC explains that:

> Reliability Coordinators and Transmission Operators must perform Real-time Assessments every 30 minutes to assess the conditions on the system and determine whether there are any actual or potential exceedances of System Operating Limits or Interconnection Reliability Operating Limits.[44]

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[42] Order No. 822, 154 FERC ¶ 61,037 at P 56.

[43] *Id.* P 58.

[44] NERC Petition at 12.

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In addition, NERC states that reliability coordinators, balancing authorities, and transmission operators must perform Real-time monitoring. NERC contends that since responsible entities "operate and monitor the [bulk electric system] according to this Real-time information, it is of critical importance that it is accurate."[45]

Discussion

30. Proposed Reliability Standard CIP-012-1 requires the protection of Real-time Assessment and Real-time monitoring data. While Real-time Assessment is broadly defined by NERC, Real-time monitoring data is not defined. Moreover, the proposed Reliability Standard does not specifically indicate the types of data to be protected. We are concerned that without further clarity, Reliability Standard CIP-012-1 may be implemented and enforced in an inconsistent manner.

31. In the Technical Rationale document appended to NERC's petition, NERC explained in more detail (relative to the language of the proposed Reliability Standard's requirements) what data should be protected under proposed Reliability Standard CIP-012-1:

> The SDT recognized the FERC reference to additional Reliability Standards and the responsibilities to protect the applicable data in accordance with NERC Reliability 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-012-1 requirements on the Real-time data specification elements 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

[45] *Id.*

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> under agreements executed with their [reliability coordinator (RC)], [balancing authority (BA)] or [transmission operator (TOP)]. Data requiring protection in CIP-012-1 consists of a subset of data that is identified by the RC, BA, and TOP in the TOP-003 and IRO-010 data specification standards, limited to Real-time Assessment data and Real-time monitoring data.[46]

The references to Reliability Standards TOP-003 and IRO-010 in the Technical Rationale document are not found in proposed Reliability Standard CIP-012-1. Instead Requirement R1 of proposed Reliability Standard CIP-012-1 only uses the terms "Real-time Assessment and Real-time monitoring data." In addition, as the Technical Rational indicates at the outset: "This Technical Rationale and Justification for CIP-012-1 is not a Reliability Standard and should not be considered mandatory and enforceable."[47]

32. Not clearly defining the types of data that must be protected under the proposed Reliability Standard could result in uneven compliance and enforcement. The term "Real-time Assessment" is broadly defined in the NERC Glossary of Terms, and the term "Real-time monitoring" is not defined at all. These terms, alone, may not be understood or enforced in a consistent manner. This concern arose during the standard drafting process in comments regarding an earlier version of the proposed Reliability Standard,

[46] NERC Petition, Exhibit F (Technical Rationale) at 1-2; *see also* Exhibit E (Draft Implementation Guidance) at 5 (providing similar context as to what data should be protected).

[47] NERC Petition, Exhibit F at iv; *see also* Exhibit E at 3 (indicating that the draft Implementation Guidance document only provides examples in achieving compliance).

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which was later modified.[48] Still relevant, however, are concerns raised regarding the potential ambiguities associated with enforcement of the scope of data that must be protected. In particular, while NERC identifies Reliability Standards IRO-002-5, Requirements R5 and R6, and TOP-001-4, Requirements R10 and R11 in discussing the parameters of Real-time monitoring data, the information outlined in the identified requirements is not included in the language of proposed Reliability Standard CIP-012-1 itself and, therefore, implementation and compliance concerns may arise.[49]

33. The compliance obligations imposed under proposed Reliability Standard CIP-012-1 should be clear in order for responsible entities to effectively and reasonably implement the required protections. The lack of clarity regarding the scope of Real-time monitoring data is inconsistent with principles outlined by the Commission in Order No. 672.[50] In particular, the lack of clarity may result in: (1) a failure to establish a clear and unambiguous requirement regarding the protection of Real-time monitoring data;[51] and (2) a failure to identify clear and objective criterion to facilitate consistent and non-preferential enforcement since responsible entities will not have a clear understanding of the Real-time monitoring data to be protected.[52] Since the controls required under

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[48] An early version of Requirement R1 of proposed Reliability Standard CIP-012-1 identified the scope of the data to be protected as "data used for Operational Planning Analysis, Real-time Assessments, and Real-time monitoring."

[49] *See* NERC Petition at page 505 of pdf.

[50] Order No. 672, 114 FERC ¶ 61,104, *order on reh'g*, Order No. 672-A, 114 FERC ¶ 61,328.

[51] *Id.* PP 322, 325.

[52] *Id.* P 327.

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Reliability Standard CIP-012-1 are plan-based, the scope of data to be protected should be clear and unambiguous so that responsible entities will accurately identify vulnerabilities or risks requiring mitigation.

34. Therefore, pursuant to section 215(d)(5) of the FPA, the Commission proposes to direct that NERC develop modifications to the CIP Reliability Standards to clearly identify the types of data that must be protected. We seek comment on this proposal. In particular, we seek comment on the specific information covered by the term "Real-time monitoring" and whether a NERC Glossary definition would assist with implementation and compliance.

III. Information Collection Statement

35. The FERC-725B information collection requirements contained in this notice of proposed rulemaking are subject to review by the Office of Management and Budget (OMB) under section 3507(d) of the Paperwork Reduction Act of 1995.[53] OMB's regulations require approval of certain information collection requirements imposed by agency rules.[54] Upon approval of a collection 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. The Commission solicits comments on the Commission's need for this information, whether

[53] 44 U.S.C. 3507(d) (2012).

[54] 5 CFR 1320.11.

the information will have practical utility, the accuracy of the burden estimates, ways to enhance the quality, utility, and clarity of the information to be collected or retained, and any suggested methods for minimizing respondents' burden, including the use of automated information techniques.

36. The Commission bases its paperwork burden estimates on the changes in paperwork burden presented by the newly proposed Reliability Standard CIP-012-1.

37. The NERC Compliance Registry, as of December 2017, identifies approximately 1,250 unique U.S. entities that are subject to mandatory compliance with Reliability Standards. Of this total, we estimate that 714 entities will face an increased paperwork burden under proposed Reliability Standard CIP-012-1. Based on these assumptions, we estimate the following reporting burden:

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Annual Changes Proposed by the NOPR in Docket No. RM18-20-000					
	No. of Respondents (1)	**No. of Responses [55] per Respondent (2)**	**Total No. of Responses (1)X(2)=(3)**	**Avg. Burden Hrs. & Cost Per Response[56] (4)**	**Total Annual Burden Hours & Total Annual Cost (3)X(4)=5**
Implementation of Documented Plan(s) (Requirement R1)[57]	714	1	714	128 hrs.; $10,496	91,392 hrs.; $7,494,144
Document Identification of Security Protection (Requirement R1.1)[57]	714	1	714	40 hrs.; $3,280	28,560 hrs.; $2,341,920
Identification of Security Protection Application (if owned by same Responsible Entity) (Requirement R1.2)[57]	714	1	714	20 hrs.; $1,640	14,280 hrs.; $1,170,960
Identification of Security Protection Application (if not owned by same Responsible Entity) (Requirement R1.3)[57]	714	1	714	160 hrs.; $13,120	14,240 hrs.; $9,367,680

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Maintaining Compliance (ongoing)	714	1	714	83 hrs.; $6,806	59,262 hrs.; $4,859,484
Total (one-time)			2,856		148,472 hrs.; $12,174,704
Total (ongoing)			714		59,262 hrs.; $4,859,484
TOTAL			3,570		207,734 hrs.; $17,034,188

38. The one-time burden for the FERC-725B information collection will be averaged over three years:

- 148,472 hours ÷ 3 = 49,491 hours/year over three years
- The number of one-time responses for the FERC-725B information collection is also averaged over three years: 2,856 responses ÷ 3 = 952 responses/year

[55] We consider the filing of an application to be a "response."

[56] The loaded hourly wage figure (includes benefits) is based on the average of the occupational categories for 2017 found on the Bureau of Labor Statistics website (http://www.bls.gov/oes/current/naics2_22.htm):

Information Security Analysts (Occupation Code: 15-1122): $42.84

Computer and Mathematical (Occupation Code: 15-0000): $44.02

Legal (Occupation Code: 23-0000): $143.68

Computer and Information Systems Managers (Occupation Code: 11-3021): $96.51

These various occupational categories' wage figures are averaged and weighted equally as follows: ($42.84/hour + $44.02/hour + $143.68/hour + $96.51/hour) ÷ 4 = $81.76/hour. The resulting wage figure is rounded to $82.00/hour for use in calculating wage figures in the NOPR in Docket No. RM18-20-000.

[57] This is a one-time reporting requirement.

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39. The responses and burden for one-time and ongoing burden for Years 1-3 will total respectively as follows:

- Year 1: 1,666 responses [952 responses (one-time) + 714 responses (ongoing)]; 108,753 hours [49,491 hours (one-time) + 59,262 hours (ongoing)]
- Year 2: 1,666 responses [952 responses (one-time) + 714 responses (ongoing)]; 108,753 hours [49,491 hours (one-time) + 59,262 hours (ongoing)]
- Year 3: 1,666 responses [952 responses (one-time) + 714 responses (ongoing)]; 108,753 hours [49,491 hours (one-time) + 59,262 hours (ongoing)]

40. Title: Mandatory Reliability Standards for Critical Infrastructure Protection [CIP] Reliability Standards.

Action: Proposed revision to FERC-725B information collection.

OMB Control No.: 1902-0248.

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

Frequency of Responses: On Occasion.

Necessity of the Information: This notice of proposed rulemaking proposes to approve the requested modifications to Reliability Standards pertaining to critical infrastructure protection. As discussed above, the Commission proposes to approve NERC's proposed Reliability Standard CIP-012-1 pursuant to section 215(d)(2) of the FPA because they improve upon the currently-effective suite of cyber security Reliability Standards.

Internal Review: The Commission has reviewed the proposed Reliability Standard and made a determination that its action is necessary to implement section 215 of the FPA.

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41. 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].

42. 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, 725 17th Street NW, 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 Docket Number RM18-20-000 and FERC-725B (OMB Control No. 1902-0248).

IV. Environmental Analysis

43. 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.[58] 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

[58] *Regulations Implementing the National Environmental Policy Act of 1969*, Order No. 486, FERC Stats. & Regs. ¶ 30,783 (1987) (cross-referenced at 41 FERC ¶ 61,284).

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not substantially change the effect of the regulations being amended.[59] The actions proposed herein fall within this categorical exclusion in the Commission's regulations.

V. Regulatory Flexibility Act Analysis

44. 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.[60] The Small Business Administration's (SBA) Office of Size Standards develops the numerical definition of a small business.[61] The SBA revised its size standard for electric utilities (effective January 22, 2014) to a standard based on the number of employees, including affiliates (from the prior standard based on megawatt hour sales).[62]

45. Proposed Reliability Standard CIP-012-1 is expected to impose an additional burden on 714 entities[63] (reliability coordinators, generator operators, generator owners, interchange coordinators or authorities, transmission operators, balancing authorities, and transmission owners).

[59] 18 CFR 380.4(a)(2)(ii).

[60] 5 U.S.C. 601-12 (2012).

[61] 13 CFR 121.101.

[62] 13 CFR 121.201, Subsection 221.

[63] Public utilities may fall under one of several different categories, each with a size threshold based on the company's number of employees, including affiliates, the parent company, and subsidiaries. For the analysis in this NOPR, we are using a 500 employee threshold due to each affected entity falling within the role of Electric Bulk Power Transmission and Control (NAISC Code: 221121).

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46. Of the 714 affected entities discussed above, we estimate that approximately 82% percent of the affected entities are small entities. We estimate that each of the 585 small entities to whom the proposed modifications to Reliability Standard CIP-012-1 apply will incur one-time costs of approximately $17,051 per entity to implement the proposed Reliability Standards, as well as the ongoing paperwork burden reflected in the Information Collection Statement (approximately $6,806 per year per entity). We do not consider the estimated costs for these 585 small entities to be a significant economic impact. Accordingly, we propose to certify that proposed Reliability Standard CIP-012-1 will not have a significant economic impact on a substantial number of small entities.

VI. Comment Procedures

47. 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. RM18-20-000, and must include the commenter's name, the organization they represent, if applicable, and address.

48. 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.

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49. 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.

50. 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

51. 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.

52. 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.

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53. 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.

Document Content(s)

RM18-20-000.DOCX.....1-33

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

SUNSHINE ACT MEETING NOTICE

April 11, 2019

The following notice of meeting is published pursuant to section 3(a) of the government in the Sunshine Act (Pub. L. No. 94-409), 5 U.S.C. 552b:

AGENCY HOLDING MEETING:	FEDERAL ENERGY REGULATORY COMMISSION
DATE AND TIME:	April 18, 2019 10:00 A.M.
PLACE:	Room 2C 888 First Street, N.E. Washington, D.C. 20426
STATUS:	OPEN
MATTERS TO BE CONSIDERED:	Agenda * NOTE - Items listed on the agenda may be deleted without further notice.
CONTACT PERSON FOR MORE INFORMATION:	Kimberly D. Bose Secretary Telephone (202) 502-8400 For a recorded message listing items struck from or added to the meeting, call (202) 502-8627.

This is a list of matters to be considered by the Commission. It does not include a listing of all documents relevant to the items on the agenda. All public documents, however, may be viewed on line at the Commission's website at http://ferc.capitolconnection.org/ using the eLibrary link, or may be examined in the Commission's Public Reference Room.

1054th - MEETING

OPEN MEETING

April 18, 2019

10:00 AM

Item No	Docket No.	Company
		ADMINISTRATIVE
A-1	AD19-1-000	Agency Administrative Matters
A-2	AD19-2-000	Customer Matters, Reliability, Security and Market Operations
A-3	AD19-11-000	State of the Markets 2018 Report
		ELECTRIC
E-1	EL19-11-000	American Wind Energy Association and The Wind Coalition v. Southwest Power Pool, Inc.
E-2	EL18-33-000	New York Independent System Operator, Inc.
E-3	EL18-34-000	PJM Interconnection, L.L.C.
E-4	OMITTED	
E-5	RM18-20-000	Critical Infrastructure Protection Reliability Standard CIP-012-1 - Cyber Security – Communications between Control Centers
E-6	ER17-1357-002	Duke Energy Carolinas, LLC and Duke Energy Progress, LLC
E-7	ER17-1568-002 ER17-1568-003 ER18-1854-001 ER18-2030-001 ER18-2058-001 ER19-261-001	Southwest Power Pool, Inc.
E-8	ER19-1112-000	Flat Ridge 2 Wind Energy LLC Fowler Ridge II Wind Farm LLC Southwestern Electric Power Company Indiana Michigan Power Company Ohio Power Company

E-9	ES19-15-000	El Paso Electric Company
E-10	ES19-14-000	South Carolina Electric & Gas Company South Carolina Generating Company, Inc.
E-11	EL19-42-000	City Utilities of Springfield, Missouri
E-12	EL18-205-000	Sunrun, Inc.

GAS

G-1	RM18-11-001 RP18-415-001	Interstate and Intrastate Natural Gas Pipelines; Rate Changes Relating to Federal Income Tax Rate American Forest & Paper Association
G-2	RP15-23-000	Transwestern Pipeline Company, LLC
G-3	RP19-810-000 RP19-811-000 RP19-812-000	Tallgrass Interstate Gas Transmission, LLC Trailblazer Pipeline Company LLC Rockies Express Pipeline LLC
G-4	IS18-228-002	Buckeye Pipe Line Company, L.P.
G-5	RP18-1038-003	Northern Border Pipeline Company
G-6	OR18-15-001	Andeavor Field Services, LLC v. Mid-America Pipeline Company, LLC and Enterprise Products Operating LLC

HYDRO

H-1	RM19-6-000	Hydroelectric Licensing Regulations Under the America's Water Infrastructure Act of 2018
H-2	P-2897-048 P-2932-047 P-2941-043 P-2931-042 P-2942-051	Sappi North America, Inc.
H-3	P-14655-001	Cat Creek Energy, LLC
H-4	P-2107-021	Pacific Gas and Electric Company
H-5	P-6461-027	City of Port Angeles, Washington
H-6	P-2079-080	Placer County Water Agency

CERTIFICATES

C-1	CP17-219-001	Southern Star Central Gas Pipeline, Inc.
C-2	CP17-117-000	Driftwood LNG LLC
	CP17-118-000	Driftwood Pipeline LLC
C-3	CP17-20-000	Port Arthur LNG, LLC and PALNG Common Facilities Company, LLC
	CP17-21-000	Port Authur Pipeline, LLC
	CP17-21-001	
	CP18-7-000	
C-4	OMITTED	

Kimberly D. Bose,
Secretary.

A free webcast of this event is available through http://ferc.capitolconnection.org/. Anyone with Internet access who desires to view this event can do so by navigating to www.ferc.gov's Calendar of Events and locating this event in the Calendar. The event will contain a link to its webcast. The Capitol Connection provides technical support for the free webcasts. It also offers access to this event via television in the DC area and via phone bridge for a fee. If you have any questions, visit http://ferc.capitolconnection.org/ or contact Shirley Al-Jarani at 703-993-3104.

Immediately following the conclusion of the Commission Meeting, a press briefing will be held in the Commission Meeting Room. Members of the public may view this briefing in the designated overflow room. This statement is intended to notify the public that the press briefings that follow Commission meetings may now be viewed remotely at Commission headquarters, but will not be telecast through the Capitol Connection service.

April 2019
Commission Meeting Summaries

These are summaries of orders voted by the Federal Energy Regulatory Commission at its April 18, 2019 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-2 & E-3 – Press Release
H-1 – Press Release
C-2 & C-3 – Press Release

FERC partially grants a complaint

E-1, *American Wind Energy Association and the Wind Coalition v. Southwest Power Pool, Inc.*, Docket No. EL19-11-000. This order partially grants a complaint, finding that SPP's membership exit fee as applied to non-transmission owners is unjust and unreasonable. The order directs SPP to eliminate the membership exit fee for non-transmission owners.

FERC proposes a rule

E-5, *Critical Infrastructure Protection Reliability Standard CIP-012-1 – Cyber Security – Communication between Control Centers*, Docket No. RM18-20-000. This Notice of Proposed Rulemaking (NOPR) proposes to approve Reliability Standard CIP-012-1 (Cyber Security – Communications between Control Centers), submitted by the North American Electric Reliability Corporation (NERC) in response to a Commission directive in Order No. 822. In addition, the NOPR proposes to direct NERC to develop and submit modifications to the NERC Reliability Standards to: (1) require protections regarding the availability of communication links and data communicated between bulk electric system Control Centers; and (2) clearly identify the types of data that must be protected.

FERC accepts an uncontested settlement agreement

E-6, *Duke Energy Carolinas, LLC*, Docket No. ER17-1357-002. The letter order accepts an uncontested settlement agreement among Duke Energy Carolinas, LLC and Duke Energy Progress, LLC (collectively, Duke), the Fayetteville Public Works Commission, the North Carolina Electric Membership Corporation, the North Carolina Eastern Municipal Power Agency, the North Carolina Municipal Power Agency Number 1, and the Piedmont Municipal Power Agency. The settlement addresses Duke's proposed amendment to its Joint Open Access Transmission Tariff to incorporate a revised methodology for calculating Real Power Loss factors.

FERC grants request for extension of effective dates

E-7, *Southwest Power Pool, Inc*., Docket No. ER17-1568-002, *et al.* This order grants SPP's request to defer the effective date for certain revisions to its tariff as a result of developmental delays to SPP's new Settlement Management System. The order directs SPP to submit an informational filing no less than 30 days prior to the implementation date of its new Settlement Management System.

FERC grants a filing

E-8, *Flat Ridge 2 Wind Energy LLC et al.*, Docket No. ER19-1112-000. The order grants Flat Ridge 2 and Fowler Ridge II Wind Farm LLC (together, Sellers) authorization to make affiliate sales under existing power purchase agreements (PPAs) with Southwestern Electric Power Company, Indiana Michigan Power Company, and Ohio Power Company (together, Purchasers). Sellers and Purchasers are not currently affiliates but are expected to become affiliated when AEP Clean Energy Resources, LLC acquires Sempra Renewables LLC's interests in Flat Ridge 2 and Fowler Ridge II (Proposed Transaction). The order authorizes continued sales under these PPAs after consummation of the Proposed Transaction. The order finds that the PPAs were negotiated at arms-length several years before the Proposed Transaction and, as such, satisfy the Commission's concerns regarding the potential for affiliate abuse.

FERC grants authorization to issue securities

E-9, *El Paso Electric Company*, Docket No. ES19-15-000. This order authorizes El Paso Electric, in accordance with section 204 of the Federal Power Act, to (1) issue common stock in an amount up to $200 million; (2) issue short-term debt under a revolving credit facility in an amount not to exceed $400 million; (3) issue long-term debt in an amount not to exceed $225 million; and (4) remarket up to $100.6 million of pollution control bonds or issue replacement debt of equal value in the form of senior notes.

FERC grants authorization to issue securities

E-10, *South Carolina Electric & Gas Company, South Carolina Generating Company, Inc*., Docket No. EC19-14-000. This order authorizes South Carolina Electric & Gas Company and South Carolina Generating Company, Inc., in accordance with section 204 of the Federal Power Act to issue short-term debt securities for one year.

FERC grants a waiver

E-11, *City Utilities of Springfield, Missouri*, Docket No. EL19-42-000. This order grants Springfield's request for a limited waiver of the *pro forma* Sponsored Upgrade Agreement of the Southwest Power Pool, Inc. tariff because, under the presented circumstances, the requirement to post financial security serves no useful purpose and is unnecessary as Springfield is both the project sponsor and transmission provider.

FERC grants a declaratory order

E-12, *Sunrun, Inc*., Docket No. EL18-205-000. This order grants Sunrun's petition for a declaratory order requesting a limited waiver of the qualifying facility certification filing requirements for individual separately-interconnected residential solar photovoltaic systems with individual maximum net power production capacities of 20 kilowatt or less that together may aggregate to over one megawatt (MW) within a one-mile radius and thus may exceed the otherwise-applicable one MW exemption from the qualifying facility certification filing requirement.

FERC denies rehearing requests

G-1, *Interstate and Intrastate Natural Gas Pipelines; Rate Changes Relating to Federal Income Tax Rate*, Order No. 849-A, Docket Nos. RM18-11-001 and RP18-415-001. The order denies the requests for rehearing and reaffirms the Commission's determinations in Order No. 849. Order No. 849, issued July 18, 2018, adopted procedures for determining which jurisdictional natural gas pipelines may be collecting unjust and unreasonable rates in light of the income tax reductions provided by the Tax Cuts and Jobs Act, the Commission's Revised Policy Statement, and precedent concerning tax allowances to address the double recovery issue identified by the 2016 ruling by a federal appeals court in *United Airlines v. FERC*.

FERC orders tariff revisions

G-2, *Transwestern Pipeline Company, LLC*, Docket RP15-23-000. This order responds to briefs addressing an issue reserved for Commission resolution by a prior settlement. The parties to that settlement asked the Commission to resolve whether Transwestern's interpretation and implementation of its tariff complied with the Commission's capacity

release policies. The order addresses the supplemental briefing of the parties on the reserved issue, finds that Transwestern has not been implementing its tariff as required by the Commission's capacity release policies, and, in accordance with section 5 of the Natural Gas Act, directs Transwestern to revise its tariff to conform to the Commission's policies.

FERC grants an extension of time

G-3, *Tallgrass Interstate Gas Transmission, LLC, et al.*, Docket Nos. RP19-810-000, *et al.* This order grants an extension of time until December 31, 2020 for Tallgrass Interstate, Trailblazer Pipeline Company, LLC, and Rockies Express Pipeline, LLC to comply with certain of the North American Energy Standards Board (NAESB) Version 3.1 business practice standards related to electronic processing.

FERC approves an uncontested settlement agreement

G-4, *Buckeye Pipe Line Company, L.P.,* Docket No. IS18-228-002. The order approves an uncontested settlement between Buckeye Pipe Line Company, L.P. and shippers to resolve issues regarding Buckeye's rates for transportation of refined petroleum products (1) on its Midwest Products System from various origins in Indiana, Michigan, Ohio, and Pennsylvania to destinations in the Pittsburgh, Pennsylvania market, and (2) on its Eastern Products System from various origins in New Jersey and Pennsylvania to destinations in the Pittsburgh and Harrisburg, Pennsylvania markets.

FERC dismisses requests for clarification and denies a request for rehearing

G-5, *Northern Border Pipeline Company*, Docket No. RP18-1038-003. This order dismisses a request for clarification and denies a request for rehearing of the Commission's August 30, 2018 order accepting Northern Border's proposed tariff records to revise its bid evaluation process for available firm capacity.

FERC denies request for rehearing

G-6, *Andeavor Field Services, LLC v Mid-America Pipeline Company, LLC and Enterprise Products Operating LLC*, Docket No. OR18-15-001. This order denies a request for rehearing of the Commission's June 21, 2018 order that declined to exercise primary jurisdiction over the parties' contractual dispute and, accordingly, dismissed Andeavor's complaint.

FERC approves license surrender and decommissioning of project features and amends certain other licenses

H-2, *Sappi North America, Inc.,* Project Nos. 2897-048, 2932-047, 2941-043,

2931-042 and 2942-051. The order approves Sappi's request to surrender its license for the Saccarappa Project No. 2897 and decommission project works. The order also approves Sappi's request to amend its licenses for the four projects immediately upstream of the Saccarappa Project: the Mallison Falls Project No. 2932, Little Falls Project No. 2941, Gambo Project No. 2931, and Dundee Project No. 2942. The order finds that Sappi's proposals are in the public interest.

FERC grants a four-year successive preliminary permit

H-3, *Cat Creek Energy, LLC,* Project No. 14655-001. The order issues a four-year successive preliminary permit to Cat Creek Energy for a proposed project that would be located on Bureau of Reclamation's Anderson Ranch Reservoir on the South Fork of the Boise River near Mountain Home in Elmore County, Idaho.

FERC grants request for rehearing

H-4, *Pacific Gas and Electric Company,* Project No. 2107-021. This order grants requests filed by PG&E and American Whitewater for rehearing of Commission staff's December 17, 2018 Order Issuing New License for the Poe Project in Butte County, California. The rehearing order: (1) extends the license term from 40 to 50 years; (2) clarifies the length of a road to be included within the project boundary; (3) removes a proposed hiking trail from the project boundary; (4) restates the capacity of the project to be 114 megawatts; and (5) makes minor corrections to a table in license article 401.

FERC denies request for rehearing

H-5, *City of Port Angeles, Washington,* Project No. 6461-027. The order denies the request filed by the Public Utility District No. 1 of Clallam County, Washington (District) seeking rehearing of staff's November 29, 2018 order approving the surrender of the City of Port Angeles's license for the Morse Creek Hydroelectric Project No. 6461, located on Morse Creek in Clallam County, Washington. The order denies rehearing on the grounds that the safety inspection conducted prior to surrender was adequate to conclude that the project works were safe and the minor maintenance issues identified during the inspection do not arise to dam safety issues that must be addressed as a condition of surrender. As such, the order concludes that no further safety inspection is necessary.

FERC grants a declaratory order

H-6, *Placer County Water Authority*, Project No. 2079-080. This order grants a petition for declaratory order filed by Placer County Water Authority, licensee for the Middle

Fork American Project No. 2079, located on the Middle Fork of the American and Rubicon Rivers and Duncan, North, and South Fork Long Canyon Creeks in Placer and El Dorado counties, California. The order finds, consistent with the *Hoopa Valley Tribe v. FERC* federal appeals court decision, that the California State Water Resources Control Board waived its authority under section 401(a)(1) of the Clean Water Act to issue water quality certification with respect to the relicensing of the project, based on the repeated withdrawal and refiling of certification applications.

FERC grants a request for rehearing

C-1, *Southern Star Central Gas Pipeline, Inc.,* Docket No. CP17-219-001. The order grants Southern Star's request for rehearing of the Commission's September 20, 2018 order granting, in part, Southern Star's application for a certificate of public convenience and necessity under section 7(c) of the Natural Gas Act to acquire additional property rights and expand the certificated boundaries of its Webb Storage Field in Grant County, Oklahoma. Specifically, the order grants Southern Star's request to expand the Webb Storage Field's certificated boundary to include an additional 80 acres in Section 1 of the North Nardin area, for the recovery of migrated storage gas.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Lesson Learned

Current Drone Usage

Primary Interest Groups
Transmission Owners (TOs)
Transmission Operators (TOPs)
Generation Owners (GOs)
Generation Operators (GOPs)

Introduction
Some entities have begun using unmanned aerial vehicles (UAVs), commonly called "drones," for various purposes, such as major storm damage survey, line repair, substation/switching station and line inspections, power plant inspections, wind farm, gas pipeline inspections, and security. Many transmission tasks currently done with helicopters can be completed by or supplemented with drones, resulting in reduced cost, increased safety, and more schedule flexibility. Additional uses and benefits are likely to develop through utilizing this emerging technology.

Photo courtesy of First Energy

Reliability & Resilience Benefits

Storm damage recovery
Like helicopters, drones can provide visual access to areas that are otherwise difficult to enter in order to accelerate assessment of damage and location of hazards. This allows the entity to efficiently allocate resources, prioritize needs, and estimate the time and material required to support a rapid recovery.

Photo courtesy of First Energy

From the Hurricane Harvey and Irma Reports: "Unmanned aerial drones were used to perform damage assessments on inaccessible transmission and distribution lines." "Aerial drones were effective to assess damage, evaluate work conditions, and enable real-time situational awareness. Infrared capabilities helped identify equipment that needed further inspection."

One entity assisting Puerto Rico's recovery from Hurricane Maria reported the development and use of a method to string lines between structures on either side of a canyon or otherwise uncrossable terrain. This method used a drone to fly a parachute cord leader from one structure to another that then allowed for a rope to pull the wire across the terrain.

Photo courtesy of Duke Energy

Line, Structure, and Substation Inspections

Like helicopters, drones may carry cameras (4k resolution is common) and/or other equipment that can facilitate the assessment of an entity's infrastructure to determine a variety of conditions related to asset health. Though previously used from the ground or a helicopter, many of the sensors that can be integrated into the UAV's payload have been used historically to assess the condition of various electrical components. Below are some examples of sensors that can be utilized:

- Infrared (IR) cameras can examine splices, insulators, bushings, and other equipment for hot spots.
- Corona cameras can check for small arcs and discharges
- RF noise detectors can identify internal issues.
- LIDAR can be used to gather survey grade data for analysis of site conditions including vegetation concerns.
- Visible light (RGB) cameras can be used to collect imagery data including:
  - Line assets
  - Station assets
  - Telecommunication towers/equipment
  - Right of way
  - Environmental surveys (i.e. wetlands, access roads, and avian protection)
  - Construction/restoration progress

Photo courtesy of Duke Energy

Drones have the ability to get closer to equipment and get into more congested spaces than a helicopter can and provide perspective not available from the ground, and this can provide higher quality inspection results for the entity and its customers. Drones have been used to produce 3D models of substations or construction sites and also perform difficult to access nameplate verifications.

Photo courtesy of Xcel Energy

Station Security

One entity is known to be using drones to evaluate substation security alarms prior to risking personnel entry. They drive up to an appropriate stand-off distance from the station and operate the drone from there to determine whether a threat remains in the station.

The entity reported a large reduction in CIP-014 assessment time for difficult locations (including a manned hydro plant, which has a hard to access station above the dam; another case involved accessing a station across a river with no nearby bridges).

The entity also occasionally assists local law enforcement and other first responders with aerial viewing to assess situations in real time.

Infrared cameras can see people, warm vehicles, and animals at night. (Note: night flight requires a waiver from the Federal Aviation Administration (FAA))

Generation Inspections

Drones can inspect dams, spillways, solar farms, and wind turbines faster and safer than people on rigging or helicopters.

(Note: indoor use of drones is permitted without regulation (e.g., internal boiler inspections, confined spaces, etc.))

Photo courtesy of Duke Energy

Lesson Learned

Current and potential drone uses are still being explored, so don't overpromise–drones have model-specific capabilities and limitations, as do operators. Government regulations and entity processes also impose limits.

- **Decision Makers Need Informed of Cost/Benefit**
  - To get approval to pursue a drone program there needs to be a determination of likely costs and benefits. Unless there is some experience to reference, the accuracy of those determinations are questionable.
  - One entity reports a very high return on investment when it used drones for survey photos (e.g., station new build and modification and other project planning, GIS overlay). Also, survey photo sharing with emergency preparedness personnel provides more current info than Google Maps.
  - Having an internal governance policy and procedures for drone use is important to stand up an effective, well managed drone program.
- **Rules one entity set for itself**
  - For determining causes of line outages, if unable to have a helicopter patrol a line, a drone can be used to patrol one mile sections of a line using visual line-of-sight methods.
  - During tower restoration, use drones to take pictures of each tower before and after replacement.
    - Provide updates to management on restoration progress
    - Show that access roads were removed and that the property was restored after they are no longer needed

  - Drones provide a safer method of viewing equipment that may otherwise need to be viewed by helicopter.
- Drones can review vegetation encroachment on transmission and distribution lines.
- Use drones to inspect nests that have been built on top of structures.
- Drones can survey wetlands before and after construction to show that it has not been disturbed as part of construction.
- Drones can patrol lines with a high operation rate to reduce future operations by inspecting poles, lines, insulator, and other equipment associated with the line.
- Use drones to inspect communication towers, stacks, cooling towers, and industrial buildings.
- Use drones to inspect the condition of wooden pole substations.

Photo courtesy of First Energy

- **When using drones for patrolling lines:**
  - Receive approval from TOPs prior to flying drones near lines that are 69kV and higher.
  - Stay 10 times further than the minimal approach distance of the line at all times to prevent coming into contact with the line or any energized equipment (cameras are high resolution with 30X optical zoom plus another 6X digital zoom that provide for excellent quality at these distances or greater).
  - Hovering over energized lines is not permitted.
  - Flying between phases of a line is not permitted.
  - Drones must be flown within visual line-of-sight as per present FAA regulations
  - Notify land owners, customers, et. al. that are in the affected area well in advance.

Photo courtesy of First Energy

- **Understand Drone limitations**
  - Many entities are testing with hobbyist-level drones whose flight times between recharging are 20 to 45 minutes, limiting their use. Those short flight times are acceptable for substation or generation plant inspections, but do not support lengthy line inspections. A commercial-grade drone (sometimes gasoline powered) is needed for longer flights and heavier payloads.
  - For safety, drones, piloted fixed-wing aircraft, and rotorcraft must be kept separated. Without specific flight plans and commercial drone pilot certification, utility drones cannot fly in controlled airspace. Drones (non-military) are only permitted to fly at or below 400 feet above ground level (AGL) or, if higher than 400 feet AGL, remain within 400 feet of a structure. FAA rules for deconflicting storm ravaged area airspace between search, rescue, emergency aid, and utility recovery efforts are still being refined.

- **Recovery on loss of guidance signal**
  - When flying too close to energized conductors, it is possible for GPS or operator communication signals to be interrupted due to electromagnetic interference, and operating a drone in manual mode can be challenging as the aircraft is much less stable.
  - Some drones have a return-to-home (or other waypoint) or hover feature when it loses connection with the pilot controller. The return-to-home routine often has a set altitude to which the drone will go to. This is generally safety-related routine; however, the starting position when a return-to-home routine is initiated is important.
    - If the return-to-home routine starts when an object is in the path, adverse results may occur. Planning the approach to electromagnetically noisy environments is therefore important (e.g., favorable choice of "home" location, distances to maintain from EM noise sources, staying out from under / between objects).
    - Low battery or low fuel may also initiate a return-to-home routine.
  - Loss of GPS would result in the aircraft unable to hold position, requiring more attention and control from the operator. Environmental factors, like wind, could push the aircraft around. The aircraft will stay in level flight, just not over a fixed point.
- **FAA Regulatory Requirements must be addressed**
  - FAA regulations under 14 CFR Part 107, the small drone rule for commercial and public agency operators, provide for certification and flight plans in controlled airspace for most drones capable of useful applications. Beyond visual line of sight (BVLOS) of the operator in command has more stringent FAA requirements, but really opens up the usefulness of drones for survey and line inspections. Through rigorous testing, the approved entity confirmed that flying drones BVLOS to perform line inspection is safe, accurate, and cost effective.
  - The ability to fly BVLOS is needed to perform long line inspections and extensive storm damage survey work. A few entities have their own certified drone pilots for BVLOS. Others have used contractors with BVLOS-certified pilots.
  - The FAA will issue waivers/authorizations to waive certain requirements of Part 107 if an applicant demonstrates they can fly safely under the waiver without endangering people or property on the ground or in the air. To request a Part 107 Waiver or Operation in Controlled Airspace, applications must currently be submitted on-line through FAA's Drone Zone Portal. There are cell phone apps for filing flight plans.
  - The FAA will strive to review and issue decisions on waiver/authorization requests within 90 days. Processing times will vary based on the complexity of the request. First responders and other entities responding to emergency situations may be eligible for expedited approval through the Special Governmental Interest process.
  - The Association for Unmanned Vehicle Systems International (AUVSI) is a non-profit organization that has the Trusted Operator Program, a new certification program available to remote pilots and unmanned aircraft system (UAS) training organizations. Through the Trusted Operator Program, operators and organizations can distinguish themselves in a growing marketplace by holding themselves to a "higher standard of safety and professionalism."

- Level 1 covers low-risk operations under the FAA's small UAS rule (Part 107)
- Level 2 is for operators who require a Part 107 waiver

Photo courtesy of First Energy

- Level 3 provides standards for operating in "safety-critical" areas, such as for inspection of infrastructure

Photo Courtesy of First Energy

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This document is designed to convey lessons learned from NERC's various activities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing Reliability Standards. Compliance will continue to be determined based on language in the NERC Reliability Standards as they may be amended from time to time. Implementation of this lesson learned is not a substitute for compliance with requirements in NERC's Reliability Standards.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Lesson Learned

Substation Fires: Working with First Responders

Primary Interest Groups
Transmission Owners
Generation Owners
Distribution Providers

Problem Statement
Two substation fire events occurred that highlight the importance of having an incident response procedure and command structure.

In the first case, a fire occurred due to an arc flash on a 12 kV feeder circuit breaker within an enclosed substation. Although the fire department was dispatched to extinguish the fire, the ability to respond to the substation fire was delayed.

In the second case, a 160 MVA, 230 kV/35 kV Transformer high-side bushing failed in an outdoor substation resulting in multiple operations removing the transformer, a 230 kV bus, and three transmission circuits in a large metropolitan city. An incident command post was established across the street promptly on the arrival of utility and fire department personnel.

Photo credit: Rick McClure

Details - Case 1
A fire resulted from an arc flash incident on a 12-kV feeder circuit breaker cabinet in an enclosed substation. Four technicians present in the substation heard an explosion and began evacuating. Per the safety procedure, they evacuated safely through the front entrance and called their supervisor and distribution operations after ensuring everyone was safe. Not knowing if the fire department was automatically notified, they called 9-1-1. Even though the fire department was dispatched to extinguish the fire, the response was delayed due to the following factors:

- The crew on-site initially thought that the station fire alarm had automatically notified the fire department. However, alarming to the third-party monitoring company about the fire did not operate as designed because the firmware on the alert system had not been updated.

- Having four different individuals from various workgroups in the substation led to confusion of who was the incident commander. Effective communication to the fire department was hampered because it was not clear who had the authority and responsibility to make the call. The operators, who had the responsibility to call the fire department, did not because the on-site crews told them incorrectly that the fire department was already notified and on their way.
- Normal station access was prevented when service for the substation was interrupted. It was discovered that a card reader had a secondary backup battery (unknown to personnel) and it failed to operate due to the battery being dead. Someone from the corporate office was asked to travel with a key to open the substation doors; however, before they could arrive, the fire department had to perform a forced entry into the substation.
- Even though the company had provided the fire department with training on how to respond to substation fires, it was not communicated back to the company that the fire fighters would not enter the substation without an escort. This miscommunication slowed the response of fire fighters to enter the facility.

Corrective Actions (for Case 1)

- The first person to discover a fire must report it via 911 regardless of any central station monitoring that may be present.
- Perform a review of the effectiveness of the fire entry procedure for indoor substations and update it as appropriate along with the applicable training.
- Expand the fire entry procedure to include situations where qualified personnel could already be present at the site. This procedure should addressing the following:
  - Who is the incident commander?
  - Who is supposed to call for the fire department?
  - What assistance if any do they provide the fire department?
- Review fire entry requirements with the fire department to clarify the requirement that utility personnel should not enter the building prior to the fire department declaring the building safe.
- Coordinate with the fire department to establish the practice of immediately mobilizing a foam unit in the case of substation and switchgear fires whether indoor or outdoor.
- Ensure expectations from the fire department are understood and documented on what assistance company personnel are supposed to do.
- Ensure additional equipment inside the substation is maintained. For example:
  - Replace battery backup for card readers
  - Perform maintenance on Fire Alert system including any firmware or software upgrades
- Ensure fire alarms at all substations work on the operator human machine interface (HMI) screen and are audible.
- The third-party fire alarm monitoring company reported that they did not receive automated notification of the fire alarm due to an error in the fire alarm panel's communication system, and

thus did not call the fire department. The alarm panel communication to the monitoring company was last tested successfully during an annual fire system inspection by the third-party monitoring company. There should be periodic reviews of the fire alarm panel's operation and review communication systems at other facilities managed by the third-party monitoring company.

Details - Case 2

Photo credit: Rick McClure

A 160 MVA, 230 kV/35 kV transformer tripped and locked out on differential protection. Initially, the fault was C-phase-to-ground, but evolved into a 3-phase fault. The fault magnitude was 25,000 amps at 230 kV and it cleared in four cycles. The transformer bank protection operated as intended, but the fault caused the 230 kV C-phase bushing to burst into flames and ignite mineral oil in the transformer. The fault also caused the transformer's 230 kV C-phase lead to drop onto the 230 kV Bus 1, resulting in Bus 1 tripping on differential protection as intended, open-ending three additional 230 kV transmission lines.

As utility personnel arrived on the scene, they found the transformer on fire and the local fire department setting up a command post across the street. People nearby were trying to record everything, which made it harder for company personnel to get where they were needed.

As the utility could not initially determine how long it would take until they could restore power, there were concerns about people gathering in the area and potential looting, so the police department was called in to patrol the area.

After utility personnel had a brief discussion with the local fire department and performed an inspection of the station, it was determined that the transformer failure had caused a loss of the AC station service power supply, and a DC system ground.

The entire station needed to be de-energized along with an additional 230 kV line that was strung over the top of the failed transformer (but did not terminate inside the substation). Utility personnel contacted the control center to report the conditions and began emergency switching remotely to de-energize the station.

After de-energizing all facilities at the station, all DC circuits needed to be de-energized as well due to the DC ground in order to preserve the station batteries (for later switching during post-fire recovery) since the station was without AC power for the battery chargers. Note: This also removed the station phone from service.

The utility personnel explained to the fire department what was on fire and the amount and type of oil involved. There was a danger that, if the de-energized transformer's fire was simply put out with a water fog, the retained heat in the coils could cause a second fire for up to a few days, so smothering with foam or a longer term fogging and cooling was necessary. The local fire department did not have a foam truck, and the nearest one was over an hour away.

Photo credit: Rick McClure

When explaining the situation to the fire department, the utility personnel used a google maps overhead view of the station. This was useful to the fire department's planning their approach and actions. They used a water fog on the transformer to bring down the heat. The use of water fog rather than a stream helped reduce, but did not eliminate, concerns that soot and water would get into the storm drain that leads to the river and that the oil containment could overflow. The foam would have been better if it had been available. Utility personnel used an infrared camera to make sure the equipment was cooled and would not reignite. It took approximately two hours for the local fire department personnel to extinguish the fire.

Corrective Actions (for Case 2)

Approximately 13 hours after the initial fault, all station load was restored by making temporary repairs of station equipment and picking up the load from substation bus-ties. The utility had a new 160 MVA transformer to replace the damaged one plus a temporary 60 MVA transformer stored at the site prior to the incident that expedited permanent repairs (approximately 30 days after the transformer failure).

Lessons Learned (from both events)

1. Before a substation fire occurs, establish a working relationship with local fire departments. Discuss the hazards present in substations and exchange information on how to address substation fires. This document can be a starting point for that conversation.
2. In the first case study, the protocol for assuming the Incident Commander role, as outlined in the company's fire entry procedure, was not clearly understood by some of the utility personnel who were present and responded to the incident.
    a. **Emergency Notifications:** Even though the station may be equipped with central station monitoring, the generic notification to the fire department does not properly prepare them for the conditions they may face.

FEMA's National Incident Management System (NIMS) defines the **Incident Command System (ICS)** as "a standardized approach to the command, control, and coordination of on-scene incident management that provides a common hierarchy within which personnel from multiple organizations can be effective." The NIMS approach is scalable and works across industries. A discussion of ICS for utilities is here. There is ICS training available at several levels. ICS 100 provides a baseline level.

i. The first person to discover a fire is responsible to report it via 911 regardless of any central station monitoring that may be present (this is often a local law). Verbal notifications can convey actual conditions and the number of personnel present whereas central station notifications to 911 are generic. The 911 call from personnel at the site may provide information on what is fire, whether a hazmat company will be needed, whether specialty apparatuses (e.g., a foam tender) will be needed, or whether an ambulance needed (note that many locations automatically dispatch one with the fire dispatch). 911 call minimum content can be memorialized into a checklist and reinforced with training.

ii. Facilities that have central monitoring should have a sign stating words to the effect of: "The fire detection system in this station is centrally monitored. Any inspection testing or maintenance work on this system requires notification to the alarm company to prevent inadvertent dispatch of fire department. In the event of a fire, 911 must also be notified in parallel that there is a fire within the station."

iii. All station fire alarms must be working to design criteria set forth under NFPA 72

b. **Incident Command:** In order to have the best alignment with first responders' training and expectations (or to work across other industry interfaces in larger scale events) use the framework of the Incident Command System, which provides clear linear paths for communication that surround an organization chart. Entity personnel responding to a substation fire should be trained to the basic ICS 100 level.

c. **Predetermine an Access Plan:** Fire service personnel, in many cases, are not fully trained or prepared to deal with the electrical/industrial hazards found in a substation. Any entry into the station must have an escort; preferably a station operator who is capable of not only explaining the hazards but mitigating such hazards where applicable, such as performing switching.

i. Develop a joint access procedure with the local fire department. This should define who is authorized to provide an escort from the utility and a means to identify the utility representative in charge. The procedure should further define command and control steps for implementing ICS and assigning roles and responsibilities to meet incident objectives.

ii. A substation operator is likely to be the initial POC for the fire services until qualified management arrive on site; however, in the absence of an operator, the most senior personnel at the site should be the single voice for the company. Note: If the individual is not an operator, the discussion should be limited to personnel accountability and evacuation.

"The Hat" – Identifying the Point of Contact / Incident Commander: Some entities use a different hard hat color identify its POC/IC for first responders. Standard NIMS ICS vests can also be used. During an emergency, the station operator or senior personnel onsite don that different colored hard hat (and /or vest) to stand out from the other company employees. Through prior communication and training, members of the first response community have been conditioned to seek out the "Hat" on arrival to a substation emergency. In addition, the fire services are clearly instructed NOT to take any tactical direction from anyone unless they are wearing that color of hard hat. Entity personnel should be trained to direct all question from members of the first response community to the "Hat" and refrain from providing their own opinions to ensure there is one clear and consistent message.

iii. During an incident, at least one dedicated district operator should be assigned to the incident to expedite switch moves in support of mitigation and recovery efforts.

iv. If possible, the operations group should dedicate multiple transmission system operators for the duration of the incident. One operator can coordinate and communicate amongst the control center, works crews, and the incident commander. The second operator can handle logging of event times, issue work authorizations, deliver accident prevention tags, and make reports to the first operator. A third operator can assist with switching under the direction of the operator in charge.

v. The fire services should be directed to find a safe staging area until the arrival of qualified personnel who can direct tactical operations. The location of the safe staging area is defined by smoke or PCB inhalation hazard and the potential for secondary explosions.

vi. Remember, the fire department's primary concern is life safety. Once all personnel have been accounted for the sense of urgency ramps down. Fire conditions and proximity to neighboring properties may cause the fire department to take defensive actions to protect these exposures. This is perfectly acceptable; however, they should be reminded that, during this process, water streams should not contact station equipment.

vii. Consider each mode of failure that could occur within a station along with the hazards that result. Discuss these with the local fire department to determine response tactics necessary for mitigation and any gaps in necessary equipment and resources.

3. **Forced Entry/Company Escort:** In most substation fire cases, personnel can be easily accounted for and whatever is burning cannot be saved. As such, there is no value in forcing entry to these locations. These are low frequency, high-hazard locations that should not be entered without an escort.

   a. Fire department personnel do not encounter enough substation incidents to sharpen their skill set to the degree they can operate within these facilities alone. Fire department members are escorted by the incident commander (See "The Hat") or a fire brigade member designated by the incident commander if conditions require that level of PPE.

   b. Access Systems:

      i. Card readers that are used as the primary means of station access must be maintained in good working order.

      ii. Consideration should be given to the installation of a mechanical locking system for emergency access. As opposed to a traditional key access system, a push-button combination system would could be a viable alternative. The access code during an emergency could be obtained from the local control center and changed following an emergency to prevent bypass of card reader systems.

Alleviating Forced Entry: Forcing entry into a staffed substation is a problem. Forcing entry to an unstaffed substation is a recipe for disaster. Condition your fire department to stay out and take defensive roles in protected exposures as need be.

Substations in urban settings with discreet exterior facades need special signage: how does the fire department know that there is a high-hazard substation on the other side of the door? There is an entity that has arranged to use a sign on its doors that is a replica of the local fire department's logo. This catches the attention of arriving fire department units and serves as a "STOP SIGN" cautioning against forced entry.

4. **Incident Size-Up:** On arrival, the incident commander should partner with the senior fire officer and conduct a size-up of the incident. The primary focus of the size-up is life safety. The central concern is not what's burning, but what's in service and being impinged by fire that can fail and injure employees and first responders. The first order of business is to evaluate equipment surrounding the fire in 360 degree pattern.
5. **Transformer fire contingencies:** If a transformer fire has been confirmed, the incident will span multiple operational periods. As such, consideration should be given to deploying basic equipment to the site even while the incident size up and needs assessment is being performed.
    a. As a priority, vacuum tankers and a frac tank (mobile liquid storage tank with a capacity of 20,000 gallons – vacuum tankers recover oil/water and send it to the frac tank). Light towers, bathrooms and a mobile office trailer may be needed.
    b. Consideration should be given to weather conditions. Transformer replacements usually come with a large staffing contingent. Tents with heat/ac work well for meals and safety briefings.
    c. A Transformer Fire rule of thumb – as you conduct the assessment, if you notice that the heat coming off the transformer is so intense it impacts your ability to walk through an area, then you should make a request to the fire services to set up a fog line between the transformer and equipment that needs protection. If so equipped, it may be prudent to set off deluge on adjacent transformers.
    d. A second consideration is the migration of flammable oil into trenches with control wiring. In addition to possibly shutting down station motor operated disconnects, it could cause motor operated disconnects to open under load.
6. **Command Center:** It is very useful to create a command center area with a way to map out and draw the station (use an easel, white board, tape paper to the side of a vehicle, etc.). The utility's operations group should provide the utility's incident commander of substation equipment fires to make sure that safety and the restoration of customer load are prioritized and not permanent repairs. Once a chain of command is established for all participating groups, the names need to be listed on an easel or white board at an established command center.
    a. Improve preparedness by installing a fire department lock box at important stations. The box should be mounted near the main exit of the facility where you would meet incoming first responders. Each lock box should have book which contains the following:
        i. Site plan: general equipment layout with entrance/exits, location of fire department connections and direction of grade for run-off of fire suppression agent

Polychlorinated biphenyls (PCBs):
PCBs are toxic, may cause cancer, and were once widely used as dielectric and coolant fluids in electrical equipment. In 1979, the Environmental Protection Agency banned the production and importation of PCBs and has had rules for its disposal since 1978.

Large electrical equipment built prior to the 1979 ban may continue to use PCBs for the life of the equipment as long as it does not leak. Therefore, there are some installations where PCBs may still be found–not just utility owned, but industrial sites also (some were 'retired in place'). While these are generally older installations, reuse of older equipment at newer sites does happen.

>1 PPM / PCB's is a health hazard. In response, fire department personnel should wear structural firefighting gear and SCBA while operating at any utility fire where reasonable contact with smoke and liquid can occur.

For emergency response purposes consider all smoke and liquid above >1 PPM/PCB's.

ii. Chemical/SDS data: Such as transformer oil, dielectric fluid, eidisol XT (cap bank), sulfur hexafluoride, sulfuric acid (station batteries)

iii. An aerial photo: To support staging of fire apparatus and identify potential areas that may need to be evacuated based on wind

iv. The highest station voltage and safe standoff distances for approach and the application of water based suppression agents: (examples)

(1) 138,000 Volts: 75' Straight Stream – 15' 30 Degree Fog

(2) 345,000 Volts: 125' Straight Stream – 25' Fog

v. A PCB Statement: indicating that all smoke and liquids should be treated as PCB's until sampling is completed (unless absolutely known that none are at the station). All members exposed to smoke or liquids should be deconned

vi. One line drawing of the station (electrical print)

Preparedness Drawings & Photos

The second case study demonstrated the importance of having a computer / tablet or photographs to display aerial views of the substation at the command center to help coordinate fire-fighting efforts with the local police and fire departments who were not familiar with the substation layout. It was also important to have a power system map to help illustrate the affected circuits during the outage to all participating groups. This information could be kept in the recommended "Lock Box."

b. To ensure integrity of information within lock box have a key box mounted on lock box. Glass on key box must be broken to access key for entry to lock box.

c. Identifying tools, such as ICS vests and a hard hat, for designating the Incident Commander should also be placed in the box. This will help identify the IC (and other positions) to first responders.

d. It is possible to purchase a "field command post" package with white boards as described in NIMS. This will allow you to display your incident response organization chart and the laminated site drawing to identify affected equipment and the means of egress. The board should also have an area to capture incident status and goals, track assets, and keep a list of responding emergency personnel police/fire.

e. The incident commander should meet with all lead members to create a list of goals and priorities on a white board or easel. The incident commander should make sure that all group leaders provide updates as goals or situations change so plans can be updated at the command center for everyone to review.

Temporary Station Power: In the first case study, the participating groups needed to use cell phones to communicate because the station phone system did not work when the substation DC was de-energized to save the batteries.

A basic response plan should be developed for substations in the event there is a loss of light & power that is also the charging supply for station batteries. The plan should outline generator size, cable size and sets per-phase, and the length of cables as it relates to point of connection.

Note: Load boards should be outfitted with tails that have phase indications, which is the most expeditious manner in connecting generator.

7. **Transformer and other oil fires:** Ensure a carbon dioxide (CO_2) or foam truck unit is dispatched to the substation in a timely manner.
   a. Not every fire department has CO_2 or foam trucks. However, if your department has the resources, this issue may be solved with scripted message during a notification to 911 for a fire that requests a foam tender for the fire services.
   b. Another option would be to purchase and store suppression agent at the substation
   c. Based on geographic locations of the stations, it may be more cost effective for entities to purchase a few foam trailers (see 'A Foam Initiative') that could be stored at entity facilities and towed out to a fire.
8. **Metal Switchgear:** The best immediate response tactic to an energized switchgear fire is to remove its power source. The station operator, not the fire department, will do that. Nearly everything is metal, so once the electrical source is removed, the fire usually goes out. Normally the only remaining isolated pockets of fire will be from burning insulation that can be suppressed with a CO2 extinguisher. These extinguishers are Class C rated and tested safe to 100,000 volts. If the switchgear was oil cooled or insulated, foam may also be needed.

A Foam Initiative:
Foam has the ability to quickly suppress the fire, cool substation equipment, capture combustion products and some oil. Its use reduces nearby equipment damage and contamination, environmental damage, and the time it takes for the facility to be remediated and recover from the fire. Many local fire departments do not have foam equipment and cannot afford it on their own.

How much foam is needed? Some fire engines carry 15-30 gallon of foam. There are formulas for how much may be needed. Use some face-to-face planning and Q&A sessions with the local fire department at important sites with large transformers and other oil-filled devices to determine the potential foam usage ahead of time, before you really need it.

One utility, recognizing the benefits of using foam over water, has taken the initiative to purchase and preposition "foam trailers" at several of its service centers. These are small trailers, containing 20 five gallon tanks of foam concentrate, an educator, hose, an assortment of the fittings required to use the foam with standard fire-fighting equipment, and an oil spill response kit. The trailer is towed by a utility pickup truck to the fire location for the fire department to use.

Photo credit Georgia Power

The utility driver may also provide necessary local switching and station access as well as coordinate communications between first responders and the utility.

Better than Foam?
There are firefighting copolymer gels that adhere to objects they are sprayed onto and can hold hundreds of times its own weight in water, making it able to absorb much more heat than foam. Not only can these be used suppress fires, these gels can be sprayed onto nearby structures and equipment to prevent fire spreading to or damaging them.

However, these gels cannot be used on class B fires; they sink due to weight and may raise burning oil above the edge of a berm, encouraging spread. Something like foam must be used as it floats on the surface of the fuel and smothers the fire.

Advice from an expert trainer to first responders:

1. **Transformer fire suppression is two-step process**: You must capture the main body of fire on top of the unit then conduct the 360 degree assessment of the bank with a thermal imaging gun to identify isolated pockets of fire remaining within the bank. Most think transformers are reigniting when in fact the fire was never fully extinguished during the first attempt.

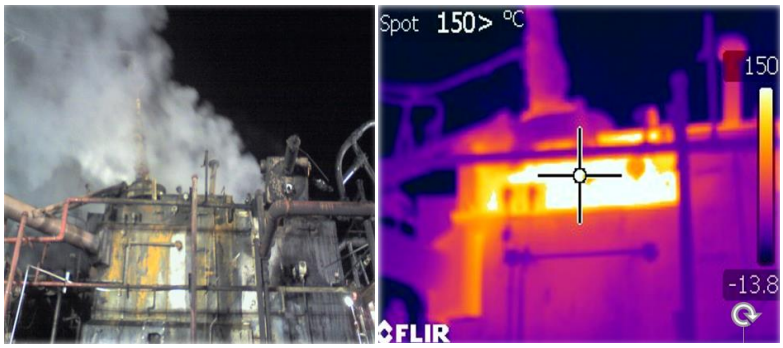

Photo Credit Anthony Natale / Consolidated Edison

2. **Switching:** The automatic opening operation of breakers on the high and low sides of the transformer should be confirmed. If at all possible, breakers should be blocked open. Isolation and grounding is not required to begin suppression operations. Suppression operations should consider a safe standoff distance based on contact voltage, a fog pattern that will eliminate leakage, a suppression agent low in conductivity, and a maximum induction pressure of 125 psi. Following that process, you would be able to hit a live conductor if overspray should occur or should a breaker reclose without adverse effects to the firefighter on the nozzle. Note: In most cases of catastrophic failures, the high and low sides are burned clear, islanding the bank so isolation and grounding is not feasible.
3. **Leakage to the Nozzle:** This refers to current flow back to the firefighter holding the nozzle during suppression operations. This process is directly influenced by the three P's. Pattern, product, and pressure.
4. **Pattern:** As you open the stream, the space between the water droplets increases and diminishes the currents ability to travel back through the stream to the nozzle. The most appropriate is a 30 degree fog pattern or power-cone.
5. **Pressure:** Increasing pressure increases conductivity. Most foam operations use 95 or 125 psi systems. Do not exceed 125 psi.
6. **Product:**
    a. **Water:** Never use water on a class B fire; based on its specific gravity, it will sink below the high-temperature transformer oil that is above the boiling temperature of water, causing a phenomena called a "boil over." This condition is NOT survivable. You will also lose the station due to rapid fire spread.
    b. **NFPA Agents:** Consideration should be given to using NFPA 11 foams or NFPA 18 water additives that can be delivered in a fog pattern. Certain foam products require a special applicator nozzle that delivers the product in a straight stream, which increases conductivity. Do not use any agent that must be delivered in this manner.
    c. **Dry-Chemical:** Most dry chemicals, such as purple-k, have a Class C rating, so they are safe to use in electrical environments. However, these agents offer no cooling value. The fire causes heat retention in the metal of the transformer, keeping the oil above its auto-ignition temperature. This makes these types of fire very persistent without the ability to cool the bank.

d. **Drafting:** In locations where hydrants/potable water do not exist, the fire services will draft from nearby water bodies. Salt water is EXTREMELY conductive and NOT recommended to be used with foam products. In addition, drafting from fresh water sources has never been evaluated. High mineral content may also increase conductivity. In locations with viable hydrants, a tanker task forces concept is recommended.

7. **Safe Standoff Distance:** The use of a fog pattern will allow you to reduce the standoff distance to the distance used for electrical contact. If the shape of the stream is narrowed, then leakage must be compensated with distance.
8. **Electrical Test Standard:** To determine if the product you intend to use is safe, use the test guide found in NFPA 18a – chapter 8 Section 8.5.

Fire Service Response Posture

- **Entity and Fire Department Preplanning**
  - Identify every failure scenario and work with the fire services to discuss the hazards and appropriate response tactics for each scenario
  - Memorialize these into a policies internally and externally. Policies should complement each other. These will also serve as the basis for training company employees and department personnel.
  - Develop critical information data sheets for each substation. This is basic information first due fire companies need on arrival this will define their initial action and behavior. In example: XXXX Substation – do not force entry – wait for the "[xxxx color] Hat" - 138,000 volts – consider all smoke and liquid to contain PCB's – do not raise tower ladder. 24 Hour control center number xxx-xxx-xxxx
  - Conduct familiarization tours with fire services.
  - As a result of familiarization, tour assist the fire company in developing a site-specific pre-incident guide. This will be used by chief officer during an incident to drive decision making.
- **Response**
  - DO NOT force entry.
  - Stage all fire apparatuses one block away. Staging should consider the hazards of smoke/ PCB inhalation and the potential for secondary explosions.
  - Go to the established meeting place and a utility rep will meet you there. DO NOT go to the fire area.
  - Utility personnel should obtain information from the "lock Box" and meet the fire department at a predetermined location to discuss the incident.
  - Have fire services take defensive action in protecting against fire. Communicate to neighboring properties if applicable.
  - Conduct a scene size-up with chief officer or their designee.
  - Identify alternate means of egress to support back-up evacuation plan if there is rapid fire spread.

- Capture and extinguish the main body of fire on top of bank.
- If applicable, conduction switching in parallel to isolate and ground equipment; the success path is to turn a class B/C fire into an easier to extinguish class B fire.
- Shoot the bank with a thermal imaging gun to identify isolated pockets of fire within.
- Use a tower ladder to drop 90 degree spray nozzle or Bresnan distributor into the primary or secondary bushing ports to extinguish isolated pockets of fire interior to the bank
- A vacuum truck should be recovering oil water run-off during suppression operations.

Photo credit Georgia Power

First Responder reviews and inputs to this document were provided by members of:
The International Association of Fire Chiefs (IAFC), and The National Volunteer Fire Council (NVFC)

Click here for: Lesson Learned Comment Form

For more Information please contact:

NERC – Lessons Learned (via email)	WECC Event Analysis
Source of Lesson Learned:	WECC
Lesson Learned #:	20190202
Date Published:	February 26, 2019
Category:	Transmission Facilities, Generation Facilities

This document is designed to convey lessons learned from NERC's various activities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing Reliability Standards. Compliance will continue to be determined based on language in the NERC Reliability Standards as they may be amended from time to time. Implementation of this lesson learned is not a substitute for compliance with requirements in NERC's Reliability Standards.

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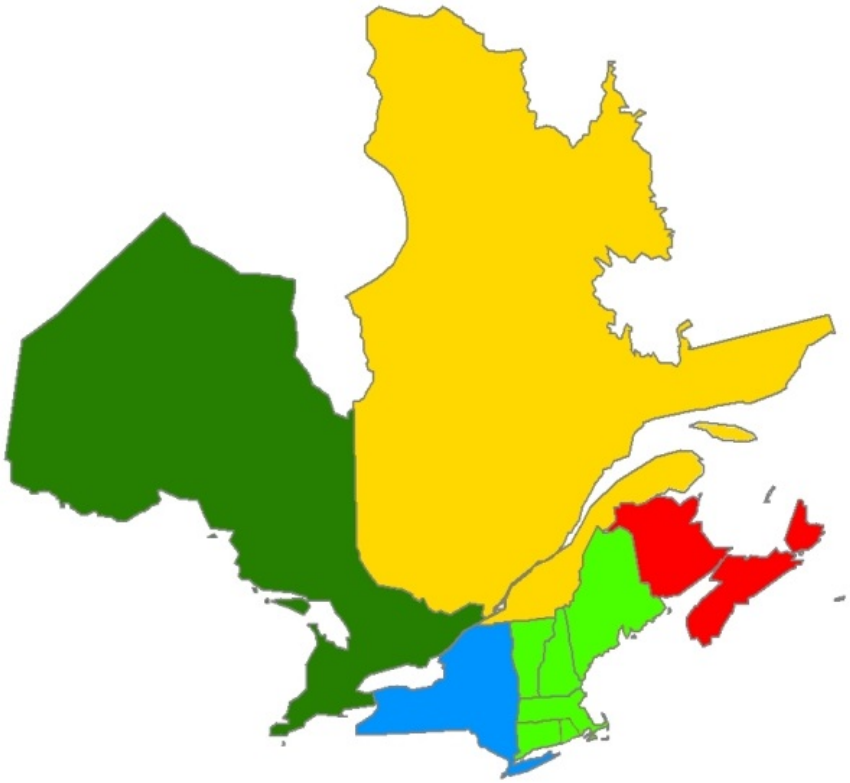
Northeast Power Coordinating Council, Inc. (NPCC)

2020 Business Plan and Budget



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Introduction

Total NPCC Resources (in whole dollars)	2020 Budget	U.S.	Canada	Mexico
Regional Entity Division FTEs	41.09			
Criteria Services Division FTEs	2.16			
Total FTEs	**43.25**			
Regional Entity Division Expenses	$16,431,647			
Criteria Services Division Expenses	$1,118,668			
Total Expenses	**$17,550,315**			
Regional Entity Division Inc(Dec) in Fixed Assets	**$170,000**			
Criteria Services Division Inc(Dec) in Fixed Assets	**$30,000**			
Total Inc(Dec) in Fixed Assets	**$200,000**			
Regional Entity Division Working Capital Requirement**	**($1,019,611)**			
Criteria Services Division Working Capital Requirement***	**($79,265)**			
Total Working Capital Requirement	**($1,098,876)**			
Total Regional Entity Division Funding Requirement	$15,582,037			
Total Criteria Services Division Funding Requirement	$1,069,402			
Total Funding Requirement	**$16,651,439**			
Regional Entity Division Assessments	**$15,338,737**	$XXX,XXX	$XXX,XXX	
Regional Entity Division Assessments Percentage	**100%**	XX.X%	XX.X%	
Criteria Services Division Membership Fees	**$1,065,202**	$XXX,XXX	$XXX,XXX	
Total NPCC Assessments & Membership Fees	**$16,403,939**	$XXX,XXX	$XXX,XXX	
NEL	XX	XX	XX	
NEL %	100%	XX.XX%	XX.XX%	

** Refer to Table B-1 on page 57 in Section B.
*** Refer to the Reserve Analysis on page 74 in Section C.

2020 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 to increase its total operating budget and assessments by 2.1% comprising a Regional Entity increase of 2.2% and a Criteria Services division increase of 0.6%. Additional 2020 succession implementation costs will be funded through existing Business Continuity Reserves, having no impact on assessments, and are excluded from the operating budget increase calculation. The proposed 2020 funding requirements will be satisfied by a Regional Entity division assessment of $15,338,737 and Criteria Services division fees of $1,065,202, for a total of $16,403,939. The total NPCC assessments and fees represent an increase of 2.1% compared to the 2019 total assessments and fees of $16,062,277. 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 46% U.S. and 54% 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 2020 targeted staffing level of 43.25 power industry professionals and support personnel. Details of the 2020 business plans and budget for each program area are included in Section A for the Regional Entity division. The 2020 Regional Entity division schedules are shown in Section B. Section C details the 2020 Criteria Services division business plan and budget.

Membership and Governance

NPCC monitors approximately 215 registered entities and some 448 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.

Under the Criteria Services division, NPCC will seek out and evaluate for membership, entities involved in emerging technologies to assure that those entities that have an impact on Bulk Electric System reliability are included in appropriate NPCC activities.

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 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 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.

2020 Key Goals and Key Deliverables

NERC and the Regional Entities collaborated in the development of a common operating model with complementary roles and responsibilities, an ERO Enterprise Long-term Strategy and an ERO Enterprise Operating Plan. Links to these documents, which incorporated risks identified by the Reliability Issues Steering Committee, are included in the NERC 2020 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. For example, key goals and deliverables within the Reliability Standards program area include supporting the development of risk-responsive Reliability Standards as well as facilitating a Distributed Energy Resources (DER) Forum. Within the Compliance Monitoring and Enforcement and Organization Registration and Certification program, in addition to conducting objective, risk-informed compliance monitoring, enforcement and entity registration activities, this area will be addressing increased enforcement activities and implementing the ERO Enterprise CMEP IT tool (Align). The Reliability Assessment and Performance Analysis program will be focusing on reduction of known risks to reliability and the identification and assessment of emerging reliability risks, such as changing resource composition. In the Situation Awareness and Infrastructure Security area there is an increasing focus on the identification and reduction of cyber and physical security risks through expanded outreach. In an order to achieve these goals and expanded efforts, while minimizing increases in budget, significant reprioritization within the business plan and reallocation of resources were required.

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 bulk 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, in conjunction with NERC and the other Regional Entities, has developed and deployed an ERO Enterprise-wide Compliance Monitoring and Enforcement IT tool (Align) for gathering data, analysis, and tracking of compliance information to carry out these responsibilities in a consistent and 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.

2020 Overview of Regional Entity Division Cost Impacts

The proposed Regional Entity division assessment of $15,338,737, to support the Regional Entity division operating budget of $16,157,107, is an increase of 2.2% compared to the 2019 assessment of $15,003,411.

2019 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. 2019 Projections reflect expectations based on the first quarter variance report. It is anticipated that projections could change throughout 2019 and would be reflected in each subsequent quarter's variance report.

Statement of Activities Format

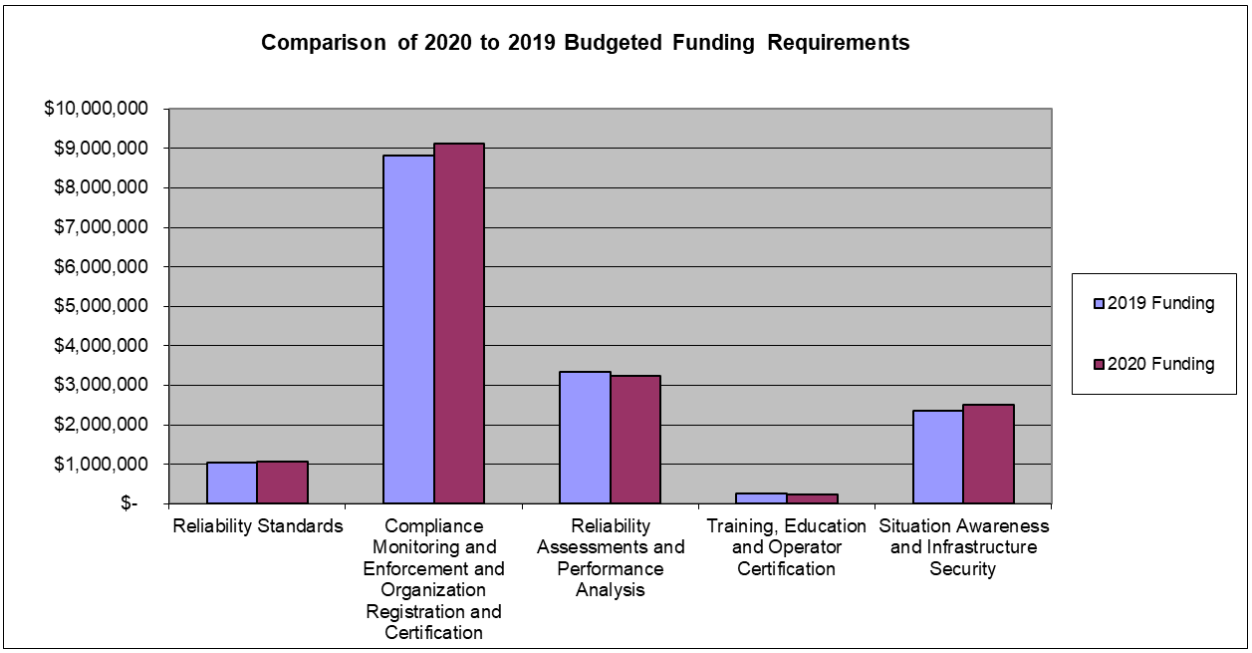
Beginning with the 2020 Business Plan & Budget (BP&B), NERC and the Regions are implementing format revisions to the Statement of Activities report. These revisions are intended to ensure that NERC and the Regions report information consistently from new accounting standards (e.g., leasing standards and right-of-use assets), provide enhanced transparency of financing activity (e.g., debt borrowing, leased-financed asset purchases, and principal payments), and streamline sections of the report related to non-cash expenses (primarily depreciation and amortization). The goal of the new format is to improve the effectiveness of the report to the reader and to provide a total budget amount that more closely reflects the amount of annual revenues required from assessments and other funding sources. One of the format revisions is that the Statements of Activities will no longer show an expense item for depreciation and an equal and offsetting credit for depreciation in fixed asset activity (which resulted in depreciation having no impact on funding requirements or actual results).

In the 2020 BP&B document, the 2019 budget has been restated to reflect the new statement of activities reporting format when comparing 2020 to 2019 to show the year-over-year budget changes on a comparable basis. As such, in the total entity and departmental Statements of Activities, depreciation expense has been removed from the 2019 operating expense budgets and projections, and an equal credit of depreciation expense has been removed from the 2019 fixed asset activity budgets and projections.

Summary by Program

Program	Budget 2019	Projection 2019	Budget 2020	Variance 2020 Budget v 2019 Budget	Variance %
Reliability Standards	$ 1,035,390	$ 1,035,390	$ 1,071,015	$ 35,625	3.4%
Compliance Monitoring and Enforcement and Organization Registration and Certification	$ 8,816,687	$ 8,671,687	$ 9,109,633	$ 292,946	3.3%
Reliability Assessments and Performance Analysis	$ 3,332,686	$ 3,332,686	$ 3,231,169	$ (101,517)	-3.0%
Training, Education and Operator Certification	$ 252,443	$ 252,443	$ 239,412	$ (13,031)	-5.2%
Situation Awareness and Infrastructure Security	$ 2,366,685	$ 2,366,685	$ 2,505,877	$ 139,192	5.9%
Total	$ 15,803,891	$ 15,658,891	$ 16,157,107	$ 353,216	2.2%

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 2019	Projection 2019	Direct FTEs 2020 Budget	Shared FTEs[1] 2020 Budget	Total FTEs 2020 Budget	Change from 2019 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	17.00	18.00	0.00	18.00	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	4.50	0.93	5.43	-0.40
Situation Awareness and Infrastructure Security	5.00	5.00	5.40	0.00	5.40	0.40
Total FTEs Operational Programs	**29.86**	**29.86**	**29.00**	**1.86**	**30.86**	**1.00**
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	0.23	2.73	0.23
Information Technology	2.00	2.00	2.00	0.00	2.00	0.00
Legal and Regulatory	1.00	1.00	2.00	0.00	2.00	1.00
Human Resources	1.00	1.00	1.00	0.00	1.00	0.00
Accounting and Finance	2.00	2.00	2.00	0.00	2.00	0.00
Total FTEs Administrative Programs	**9.00**	**9.00**	**10.00**	**0.23**	**10.23**	**1.23**
Total FTEs	**38.86**	**38.86**	**39.00**	**2.09**	**41.09**	**2.23**

[1]A shared FTE is defined as an employee who performs both Regional Entity and Criteria Services division functions.

2019 Budget and Projection and 2020 Budget Comparisons

Statement of Activities and Capital Expenditures
2019 Budget & Projection, and 2020 Budget

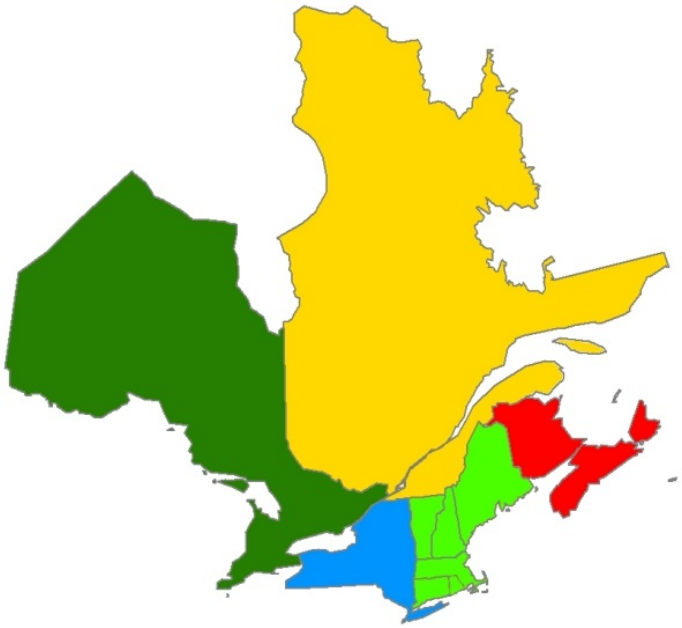
REGIONAL ENTITY DIVISION

		2019 Budget	2019 Projection	Variance[2] 2019 Projection v 2019 Budget Over(Under)	2020 Budget	Variance 2020 Budget v 2019 Budget Over(Under)
Funding						
ERO Funding						
	ERO Assessments	$ 15,003,411	$ 15,003,411	$ -	$ 15,338,737	$ 335,326
	Penalty Sanctions[1]	-	-	-	120,000	120,000
Total ERO Funding		**$ 15,003,411**	**$ 15,003,411**	**$ -**	**$ 15,458,737**	**$ 455,326**
	Membership Dues	-	-	-	-	-
	Testing Fees	-	-	-	-	-
	Services & Software	-	-	-	-	-
	Workshops & Misc Revenue	67,500	67,500	-	67,500	-
	Interest & Investment Income	-	-	-	55,800	55,800
Total Funding (A)		**$ 15,070,911**	**$ 15,070,911**	**$ -**	**$ 15,582,037**	**$ 511,126**
Expenses						
Personnel Expenses						
	Salaries	$ 7,332,280	$ 7,216,280	$ (116,000)	$ 7,704,262	$ 371,982
	Payroll Taxes	449,994	444,994	(5,000)	479,019	29,026
	Benefits	1,613,078	1,585,078	(28,000)	1,943,385	330,306
	Retirement Costs	853,511	837,511	(16,000)	882,950	29,440
Total Personnel Expenses		**$ 10,248,862**	**$ 10,083,862**	**$ (165,000)**	**$ 11,009,617**	**$ 760,754**
Meeting Expenses						
	Meetings & Conference Calls	$ 370,750	$ 406,750	$ -	$ 397,750	$ (9,000)
	Travel	845,900	845,900	-	845,900	-
Total Meeting Expenses		**$ 1,252,650**	**$ 1,252,650**	**$ -**	**$ 1,243,650**	**$ (9,000)**
Operating Expenses						
	Consultants & Contracts	$ 2,022,150	$ 2,002,150	$ (20,000)	$ 2,071,150	$ 49,000
	Office Rent	820,700	820,700	-	832,700	12,000
	Office Costs	676,347	676,347	-	685,981	9,634
	Professional Services	978,000	978,000	-	947,000	(31,000)
	Computer & Equipment Leases	-	-	-	-	-
	Miscellaneous	51,000	51,000	-	51,000	-
Total Operating Expenses		**$ 4,548,197**	**$ 4,528,197**	**$ (20,000)**	**$ 4,587,831**	**$ 39,634**
	Total Direct Expenses	**$ 16,049,709**	**$ 15,864,709**	**$ (185,000)**	**$ 16,841,098**	**$ 791,388**
Indirect Expenses		**$ (415,818)**	**$ (415,818)**	**$ -**	**$ (409,450)**	**$ 6,368**
Other Non-Operating Expenses		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)		**$ 15,633,891**	**$ 15,448,891**	**$ (185,000)**	**$ 16,431,647**	**$ 797,756**
Change in Assets		**$ (562,980)**	**$ (377,980)**	**$ 185,000**	**$ (849,611)**	**$ (286,630)**
Fixed Asset Additions (C)		**$ 170,000**	**$ 170,000**	**$ -**	**$ 170,000**	**$ -**
TOTAL BUDGET (=B+C)		**$ 15,803,891**	**$ 15,618,891**	**$ (185,000)**	**$ 16,601,647**	**$ 797,756**
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)		**$ (732,980)**	**$ (547,980)**	**$ 185,000**	**$ (1,019,611)**	**$ (286,630)**

[1] $120,000 of penalty sanctions collected to date and prior to June 30, 2019.

[2] 2019 Projections reflect expectations based on the first quarter statement of activities. It is anticipated that projections could change throughout 2019 and would be reflected in each subsequent quarter's statement of activities.

Section A – Regional Entity Division
2020 Business Plan and Budget



Section A — 2020 Regional Entity Division Business Plan and Budget

Reliability Standards Program

Reliability Standards Program Resources (in whole dollars)	2019 Budget	2020 Budget	Increase (Decrease)
Total FTEs	1.93	1.93	0.00
Direct Expenses	$665,870	$693,683	$27,813
Indirect Expenses	$359,634	$366,700	$7,066
Other Non-Operating Expenses	$0	$0	$0
Fixed Asset Additions	$10,988	$10,632	($356)
Total Funding Requirement	$1,036,492	$1,071,015	$34,523

Program Scope and Functional Description

The NPCC Reliability Standards Program Area operates in accordance with NPCC's filed and approved Regional Delegation Agreement and NERC Rules of Procedure Section 300. The program supports the ERO Standards Program Area roles and responsibilities, the ERO Enterprise Operating Plan, the ERO Enterprise Long-Term Strategy and aligns with NPCC Board of Director goals and strategies. NPCC's Reliability Standards Program Area provides an efficient and effective mechanism for stakeholders to provide input and facilitate the development of, and improvement to, NERC and Regional 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 and Regional variances which establish "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 also responsive to FERC Directives and industry risk. NERC and Regional reliability standards must ensure the bulk electric system is planned, operated, and maintained in a manner that minimizes risks of cascading failures, system separation, and instability, and also 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, and ERO Standards Variances for the northeast as required. The NPCC Reliability Standards Program Area also provides oversight to ensure that NPCC's Regional Reliability Criteria contained in the form of Directories, are developed, approved, and maintained as necessary to implement, to augment, or to facilitate compliance with NERC Reliability Standards. NPCC's reliability criteria are not reliability standards but are mandatory and subject to enforcement as outlined in the NPCC *Amended and Restated Bylaws* and various ISO tariffs, and individual interconnection agreements, as well as other executed contractual agreements. Regional Reliability Criteria may also address issues not within NERC's statutory jurisdiction for Reliability Standards, such as resource adequacy, and conform to requirements in Section 313 of the NERC Rules of Procedure.

In addition, the NPCC Reliability Standards Program Area has initiated a Distributed Energy Resources (DER) Forum. As conventional fossil fuel units and nuclear retirements are increasingly being replaced by DER on the transmission system and with grid edge DER on the

distribution system, the reliable operation of the BES as defined in the legislation could be impacted. The control systems of DER introduce new capabilities that could enhance reliability and understanding interoperability issues between transmission and distribution systems will become increasingly important. NPCC is engaged in a number of areas to ensure reliable integration into the BES and opportunities to provide industry guidance for interconnecting DER.

2020 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 acting on recommendations of the various phases of the Standards Efficiency Review project, conducting periodic reviews on existing Reliability Standards to improve their content and quality, responding to identified risks to reliability (including those that may be identified through the implementation of risk-based Compliance Monitoring and Enforcement), and addressing 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 NERC Reliability Standards, NPCC's Regional Reliability Standard for Underfrequency Load Shedding "UFLS" 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 further 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 at a stable level, driven by requests that the Regional Entity may receive or reliability issues that are identified and not under consideration by NERC. Creation of Variances to NERC Reliability Standards to address reliability concerns or to recognize the unique topology and reliability considerations of the Northeast (i.e. Québec's recognition of an asynchronous interconnection within NPCC's footprint) will be performed as necessary.
- The number of NERC and Regional standards interpretations is expected to remain low. Compliance Implementation Guidance documents, which provide approaches to being compliant with NERC Reliability Standards may be developed using NPCC's open process and other industry vetting practices. These guidance documents are currently being developed by industry and the Standard Drafting Teams and the number of 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 redundancy to the ERO standards.

2020 Goals and Key Deliverables

- Participate in the annual development and revision of the NERC's 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, support ERO efforts to address outstanding FERC Directives, and provide input in the prioritization of standards development projects.
- Support further development of cost effectiveness principles processes 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 NERC Standards Efficiency Review Project future phases and resulting activities.
- Participate in the development of ERO Reliability Standards specified in NERC's three-year Reliability Standards Development 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 under development or revision by leveraging existing NPCC Task Forces and subject matter experts and coordinate NPCC comments for Northeastern North America.
- Participate in the Enhanced Periodic Review Standing Team's grading efforts and coordinate and represent the Regional and interregional input.
- Assist NERC's review of all industry "Requests for Interpretations" of NERC Reliability Standards.
- NPCC staff and Regional drafting team volunteers will participate in the drafting of ERO standards and provide support for development of improvements to standards. Those chosen to participate in drafting of standards will provide a point of contact for the NPCC Regional input to the standard being developed.
- NPCC and its members will review and coordinate 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.
- 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 when requested.
- Monitor the NERC Reliability Issues Steering Committee "RISC" activities as they identify emerging risks and develop recommended actions to mitigate such risks. 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), Geomagnetic Disturbances, High

Altitude Electromagnetic Pulse (HEMP), changes to standards driven by inverter based DERs, etc.

- Identify opportunities and initiate Regional Variances to the NERC Reliability Standards as soon as possible, allowing incorporation into the continent wide standard during the development process.
- Conduct 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.
- Identify potential reliability benefits and impacts to the BES as a result of DER penetration.
- Conduct ongoing DER Forum activities to solicit and identify both opportunities and challenges to enhancing reliability through education, promotion of awareness and developing guidance, particularly for interconnection of utility scale DER on the Distribution System.
- Identify opportunities to improve resilience of the BES.
- Identify and coordinate reliability related issues with local governmental authorities where jurisdictional issues may exist.
- Ensure the topics addressed by the Reliability Standards align with changing industry and reliability objectives.
- Participate in reliability metrics developmental 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 Review Team activities.
- Identify opportunities and processes for cost-effectiveness analysis activities to determine the need to revise a standard during the Periodic Review or Standards Grading efforts.
- Identify any emerging interconnection-wide reliability issues which may need standards solutions and forward to the NERC Reliability Issues Steering Committee for their consideration.
- Identify opportunities to increase reliability or mitigate emerging risk through the revision of standards and their associated requirements.
- Identify any North American Electric Standards Review Board (NAESB) activities which may impact ERO standards.
- Identify potential market related issues for Regional Standards through NPCC RSC coordination and reviews.
- Participate in NPCC Compliance and Standards Workshops and any NERC workshops and webinars to promote industry awareness.

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

- No significant changes.

Reliability Standards Program

Funding sources and related expenses for the Reliability Standards section of the 2019 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 2019 Budget & Projection, and 2020 Budget						
Reliability Standards						
		2019 Budget	2019 Projection	Variance 2019 Projection v 2019 Budget Over(Under)	2020 Budget	Variance 2020 Budget v 2019 Budget Over(Under)
Funding						
ERO Funding						
	ERO Assessments	$ 1,035,390	$ 1,035,390	$ -	$ 1,063,510	$ 28,120
	Penalty Sanctions	-	-	-	7,505	7,505
Total ERO Funding		**$ 1,035,390**	**$ 1,035,390**	**$ -**	**$ 1,071,015**	**$ 35,625**
	Membership Dues	-	-	-	-	-
	Testing Fees	-	-	-	-	-
	Services & Software	-	-	-	-	-
	Workshops & Misc Revenue	-	-	-	-	-
	Interest & Investment Income	-	-	-	-	-
Total Funding (A)		**$ 1,035,390**	**$ 1,035,390**	**$ -**	**$ 1,071,015**	**$ 35,625**
Expenses						
Personnel Expenses						
	Salaries	$ 382,872	$ 382,872	$ -	$ 400,744	$ 17,872
	Payroll Taxes	22,735	22,735	-	23,034	298
	Benefits	106,764	106,764	-	110,172	3,408
	Retirement Costs	41,599	41,599	-	43,833	2,234
Total Personnel Expenses		**$ 553,970**	**$ 553,970**	**$ -**	**$ 577,783**	**$ 23,813**
Meeting Expenses						
	Meetings & Conference Calls	$ 7,000	$ 7,000	$ -	$ 5,000	$ (2,000)
	Travel	94,900	94,900	-	90,900	(4,000)
Total Meeting Expenses		**$ 101,900**	**$ 101,900**	**$ -**	**$ 95,900**	**$ (6,000)**
Operating Expenses, excluding Depreciation						
	Consultants & Contracts	$ 10,000	$ 10,000	$ -	$ 20,000	$ 10,000
	Office Rent	-	-	-	-	-
	Office Costs	-	-	-	-	-
	Professional Services	-	-	-	-	-
	Computer & Equipment Leases	-	-	-	-	-
	Miscellaneous	-	-	-	-	-
Total Operating Expenses		**$ 10,000**	**$ 10,000**	**$ -**	**$ 20,000**	**$ 10,000**
	Total Direct Expenses	**$ 665,870**	**$ 665,870**	**$ -**	**$ 693,683**	**$ 27,813**
Indirect Expenses		**$ 375,014**	**$ 375,014**	**$ -**	**$ 366,700**	**$ (8,313)**
Other Non-Operating Expenses		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)		**$ 1,040,884**	**$ 1,040,884**	**$ -**	**$ 1,060,383**	**$ 19,499**
Change in Assets		**$ (5,494)**	**$ (5,494)**	**$ -**	**$ 10,632**	**$ 16,126**
Fixed Asset Additions (C)		**(5,494)**	**(5,494)**	**-**	**10,632**	**16,126**
TOTAL BUDGET (=B+C)		**$ 1,035,390**	**$ 1,035,390**	**$ -**	**$ 1,071,015**	**$ 35,625**
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)		**$ (0)**	**$ (0)**	**$ -**	**$ 0**	**$ 0**

Compliance Monitoring and Enforcement and Organization Registration and Certification Program

Compliance Monitoring and Enforcement and Organization Registration and Certification Program Resources (in whole dollars)	2019 Budget	2020 Budget	Increase (Decrease)
Total FTEs	17.00	18.00	1.00
Direct Expenses	$5,561,849	$5,590,473	$28,624
Indirect Expenses	$3,167,761	$3,420,003	$252,241
Other Non-Operating Expenses	$0	$0	$0
Fixed Asset Additions	$96,785	$99,157	$2,372
Total Funding Requirement	$8,826,396	$9,109,633	$283,237

Program Scope and Functional Description

The NPCC Compliance Monitoring and Enforcement and Organization Registration and Certification Program (CORC) Program Area operates in accordance with NPCC's filed and approved Regional Delegation Agreement, the NERC Rules of Procedure, and individual Canadian Provincial MOUs and/or Agreements. The program supports Compliance Enforcement (Section 400) and Organization Registration and Certification (Section 500), the ERO Enterprise Operating Plan, the ERO Enterprise Long-Term Strategy, and aligns with NPCC Board of Director goals and strategies.

The CORC Program Area 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) IT Tool (Align) in the United States, including the compliance monitoring, assessment and enforcement of NERC Reliability Standards and Regional Reliability Standards;
3) In accordance with the relevant memorandums of understanding (MOU's), the implementation of the risk-based NERC CMEP in Ontario and Nova Scotia, including the assessment and enforcement of NERC Reliability Standards and Regional Reliability Standards effective in those jurisdictions,
4) The implementation of the Québec Reliability Standards Compliance Monitoring and Enforcement Program (QCMEP), including the compliance monitoring, assessment and enforcement of NERC Reliability Standards and Regional Reliability Standards effective in Quebec, and
5) The implementation of the New Brunswick Compliance Monitoring and Enforcement Program (NBCMEP) in New Brunswick, including the compliance monitoring, assessment and enforcement recommendations of the NERC Reliability Standards and Regional Reliability Standards effective in New Brunswick.

Through the CORC Program Area, NPCC strives to be a strong enforcement authority that is objective, fair, and promotes a culture of reliability excellence through risk-informed compliance monitoring, mitigation, enforcement, and registration. To accomplish this goal, CORC is

divided into three sub-program areas: Compliance Fundamentals; Compliance Audits and Investigations; and Compliance Mitigation and Enforcement.

Compliance Fundamentals

The Compliance Fundamentals sub-program area is responsible for registration and certification activities and for general compliance activities that span across the other three sub-program areas. The Compliance Fundamentals sub-program area:

- Identifies and registers the BES owners, operators, and users that are required to comply with the NERC and Regional Reliability Standards,
- Conducts Certifications in accordance with the NERC ROP,
- Leads the development of the annual implementation plans (ERO Enterprise, NPCC, Quebec, New Brunswick),
- Implements the ERO Enterprise CMEP IT tool (Align),
- Responds to any Complaints submitted to NPCC,
- Maintains any NPCC specific compliance tools or programs needed, and;
- Conducts outreach, training, and education to support the implementation of Reliability Standards.
- Conducts Inherent Risk Assessments (IRA) on registered entities,
- Conducts Internal Controls Evaluations (ICE) on volunteering registered entities,
- Assists with the development of the annual CMEP implementation plans, and;
- Provides the basis for each registered entity's Compliance Oversight Plan.

Compliance Audits and Investigations

The Compliance Audits and Investigations sub-program area is responsible for conducting all compliance monitoring activities. The Compliance Audits and Investigations sub-program area is focused on the most significant risks to the BPS. The Compliance Audits and Investigations sub-program area:

- Conducts NPCC compliance monitoring activities, including audits, spot checks, and guided self-certifications,
- Incorporates the results of the IRA and ICE into its compliance monitoring process,
- Issues reports, including audit reports, spot check reports, guided self-certification reports, and;
- Implements and maintains the Critical Infrastructure Protection (CIP) Standards Technical Feasibility Exceptions process.

Compliance Mitigation and Enforcement

The Compliance Mitigation and Enforcement sub-program area is responsible for undertaking enforcement activities in accordance with risk-based approaches and conducting technical assessments of registered entities' plans and activities to mitigate noncompliance. Depending on the jurisdiction, enforcement either makes official recommendations to the appropriate regulatory authority or assists and coordinates with NERC to make such official recommendations. The Compliance Mitigation and Enforcement sub-program area:

- Determines the relevant facts and circumstances necessary to understand each noncompliance,
- Evaluates and assigns a risk level to each noncompliance,
- Evaluates and approves the mitigation activities or Mitigation Plan for each noncompliance,
- Assesses the relevant compliance history for each noncompliance,
- Determines the disposition method for each noncompliance,

- Calculates penalty sanctions in consistent fashion, and
- Evaluates registered entities for the self-logging program.

2020 Key Assumptions and Cost Impacts

2019	Projected 2020
5 On-Site Audits	8 On-Site O&P Audits
8 On-Site CIP Audits	10 On-Site CIP Audits
28 Off-Site Audits	40 Off-Site O&P Audits
24 Off-Site CIP Audits	25 Off-Site CIP Audits
15 Spot Checks	10 Spot Checks
18 Guided self-certifications	40 Self-certifications
33 Inherent Risk Assessments	50 Inherent Risk Assessments
4 On-site O&P Internal Control Evaluations	7 On-site O&P Internal Control Evaluations
5 On-site CIP Internal Control Evaluations	10 On-Site CIP Internal Control Evaluations
216 Violations (Estimated)	225 Violations (Estimated)
Settlements Covering 50 Violations	Settlements Covering 80 Violations
0 Hearings (Unbudgeted)	1 Hearings (Unbudgeted)
1 CI (Estimated)	1 CI (Estimated)
3 Entity Certifications	2 Entity Certifications

- Compliance Monitoring activities are projected to increase in 2020 from 2019 and will be cost effectively addressed with the addition of one FTE on the compliance staff, which is offset by a decrease in contract audit costs.
- The 2020 Business Plan projects increases in Enforcement Processing activities over the 2019 Budget. It is expected that the increase in violation processing will continue in 2021. This is partly due to the increase in the number of cyber systems that are in scope for compliance in most jurisdictions.
- One Compliance Investigation is projected for 2020. Compliance Investigations are manpower intensive for NPCC staff (requiring allocation of more resources and potentially higher than normal costs).

2020 Goals and Key Deliverables

- Conduct scheduled compliance monitoring and enforcement activities pursuant to the 2020 Implementation Plans.
- Continue applying risk-based approaches for CMEP, registration, and certification activities.
- Identify potential issues related to NERC Reliability Standards as a result of compliance monitoring, enforcement and event analysis activities.
- Continue to implement compliance responsibilities in Canada based on the unique regulatory structure specific to each provincial and/or governmental jurisdiction.
- Evaluate monitoring, violation processing, risk-assessment, registration and certification program for sufficiency and effectiveness. Modify as needed.
- Collaborate within the ERO Enterprise to develop and implement a common and consistent CMEP IT tool (Align) for compliance processes, information systems, and methods among Regions.

- Provide education and outreach to the registered entities on all CMEP, registration, and certification topics, including the development and implementation of the ERO Enterprise Registration and CMEP software reporting systems and tools.
- Conduct two in-person Compliance Workshops.
- Develop annual reports for QCMEP/CMEP activity in Québec and New Brunswick.
- Develop and/or provide input on 2020 CMEP Implementation Plans (ERO Enterprise, NPCC, Québec, New Brunswick).
- Attend training necessary and/or beneficial to performing Registration, Certification, Entity Risk Assessment, Monitoring, and Enforcement activities.
- Assure that NPCC staff is appropriately trained to conduct Certification and Auditing activities.
- Provide detailed responses to oversight activity performed by NERC, FERC, and other relevant authorities.
- Continue to perform and update IRAs for registered entities.
- Continue to perform an ICE for registered entities that volunteer for such an assessment.
- Continue to assess internal controls during monitoring engagements
- Conduct 2020 Compliance Engagement Schedule based on risk to the BPS 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 updated Inherent Risk Assessment as necessary for all scheduled engagements and performing an Internal Controls Evaluation for all entities that volunteer.
- Continue to perform comprehensive enforcement investigations to determine the relevant facts and circumstances necessary to understand each noncompliance, assess the risk, and evaluate the mitigation activities or Mitigation Plan for each noncompliance. Determine the disposition method in accordance with established risk-based approaches (i.e. Compliance Exceptions, FFTs, Simplified Identification Correction Method (Québec), Settlements, etc.)
- Evaluate the mitigation activities or Mitigation Plan for each noncompliance, track the progress and verify the completion of each Mitigation Plan.
- As necessary, represent NPCC during any enforcement hearings before the NPCC Hearing Body, the NERC Hearing Body, the Régie, or the NBEUB.
- Evaluate registered entities for the self-logging program.
- Analyze noncompliance trends and associated risks in order to develop guidance to registered entities in support of a culture of reliability.
- Perform outreach (webinars, workshops) to educate entities on noncompliance root causes and on techniques for noncompliance assessment and communication associated with self-reporting to NPCC; including the provision of guidance on the development of mitigation activities that will prevent recurrence.
- Assess evolving cyber security risks for opportunities to develop internal control flow diagrams in order to provide entity guidance

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 56% of its resources on this activity.

Resource Requirements

Personnel

- One additional FTE to increase in-house expertise rather than utilizing contractor labor. The increase in personnel expenses will be offset by a decrease in Consultants and Contracts.

Fixed Assets

- No new functionality is planned for the Compliance Issues Tracking System and CMEP Data Administration Application at this time based on the planned implementation of the ERO Enterprise CMEP IT Tool (Align).

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 2020 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
2019 Budget & Projection, and 2020 Budget
Compliance Monitoring and Enforcement and Organization Registration and Certification

		2019 Budget	2019 Projection	Variance 2019 Projection v 2019 Budget Over(Under)	2020 Budget	Variance 2020 Budget v 2019 Budget Over(Under)
Funding						
ERO Funding						
	ERO Assessments	$ 8,183,815	$ 8,183,815	$ -	$ 9,002,624	$ 818,809
	Penalty Sanctions	-	-	-	69,994	69,994
Total ERO Funding		**$ 8,183,815**	**$ 8,183,815**	**$ -**	**$ 9,072,617**	**$ 888,802**
	Membership Dues	-	-	-	-	-
	Testing Fees	-	-	-	-	-
	Services & Software	-	-	-	-	-
	Workshops & Misc Revenue	-	-	-	-	-
	Interest & Investment Income	-	-	-	-	-
Total Funding (A)		**$ 8,183,815**	**$ 8,183,815**	**$ -**	**$ 9,072,617**	**$ 888,802**
Expenses						
Personnel Expenses						
	Salaries	$ 2,815,882	$ 2,720,882	$ (95,000)	$ 2,928,438	$ 112,557
	Payroll Taxes	191,849	188,849	(3,000)	202,717	10,867
	Benefits	585,543	572,543	(13,000)	732,104	146,561
	Retirement Costs	301,025	287,025	(14,000)	314,664	13,638
Total Personnel Expenses		**$ 3,894,299**	**$ 3,769,299**	**$ (125,000)**	**$ 4,177,923**	**$ 283,624**
Meeting Expenses						
	Meetings & Conference Calls	$ 15,000	$ 15,000	$ -	$ 15,000	$ -
	Travel	295,400	295,400	-	300,400	5,000
Total Meeting Expenses		**$ 310,400**	**$ 310,400**	**$ -**	**$ 315,400**	**$ 5,000**
Operating Expenses, excluding Depreciation						
	Consultants & Contracts	$ 1,357,150	$ 1,337,150	$ (20,000)	$ 1,097,150	$ (260,000)
	Office Rent	-	-	-	-	-
	Office Costs	-	-	-	-	-
	Professional Services	-	-	-	-	-
	Computer & Equipment Leases	-	-	-	-	-
	Miscellaneous	-	-	-	-	-
Total Operating Expenses		**$ 1,357,150**	**$ 1,337,150**	**$ (20,000)**	**$ 1,097,150**	**$ (260,000)**
	Total Direct Expenses	**$ 5,561,849**	**$ 5,416,849**	**$ (145,000)**	**$ 5,590,473**	**$ 28,624**
Indirect Expenses		**$ 3,303,230**	**$ 3,303,230**	**$ -**	**$ 3,420,003**	**$ 116,772**
Other Non-Operating Expenses		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)		**$ 8,865,080**	**$ 8,720,080**	**$ (145,000)**	**$ 9,010,476**	**$ 145,396**
Change in Assets		**$ (681,264)**	**$ (536,264)**	**$ 145,000**	**$ 62,141**	**$ 743,406**
Fixed Asset Additions (C)		**$ (48,392)**	**$ (48,392)**	**$ -**	**$ 99,157**	**$ 147,550**
TOTAL BUDGET (=B+C)		**$ 8,816,687**	**$ 8,671,687**	**$ (145,000)**	**$ 9,109,633**	**$ 292,946**
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)		**$ (632,872)**	**$ (487,872)**	**$ 145,000**	**$ (37,016)**	**$ 595,856**

Reliability Assessment and Performance Analysis Program

Reliability Assessment and Performance Analysis Program Resources (in whole dollars)	2019 Budget	2020 Budget	Increase (Decrease)
Total FTEs	5.83	5.43	-0.40
Direct Expenses	$2,216,468	$2,169,556	($46,912)
Indirect Expenses	$1,086,356	$1,031,701	($54,655)
Other Non-Operating Expenses	$0	$0	$0
Fixed Asset Additions	$33,192	$29,913	($3,279)
Total Funding Requirement	$3,336,016	$3,231,169	($104,847)

Program Scope and Functional Description

NPCC, through its top technical committee, the Reliability Coordinating Committee (RCC), integrates the deliverables of its Task Forces' and Working Groups' Reliability Assessment and Performance Analysis (RAPA) related activities.

Seasonal assessments of the overall NPCC resource adequacy 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 criteria 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.

2020 Key Focus Areas

In collaboration with NERC, Key Focus Area activities for 2020 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.
- 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 ERO activities to identify key reliability risks and appropriate projects designed to enhance reliability and/or mitigate risks.
- Providing technical resources to support NERC special reliability assessments which focus on specific reliability risk areas in geographic areas with specific identified reliability concerns.
- Advancing analytical capabilities for identifying and determining reliability risks and conducting associated related reliability assessments.

Eastern Interconnection Reliability Assessment Group (ERAG)

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 Committee. These assessment-related activities support ERO Goal 3: "*Reduction of Known Risks to Reliability*" and 4 "*Identification and Assessment of Emerging Reliability Risks*."

NPCC RAPA staff participates with the ERAG Committee as one of the four Eastern Interconnection Regional Entities, and acts as the liaison between the ERAG MMWG and the NPCC SS-37 Working Group.

ERAG Committee Activities 2020 Goals and Deliverables

- Transition the steady state and dynamic simulation base case data compilation and development work from ERAG to the Eastern Interconnection Planning Collaborative (EIPC).
- Support EIPC designation and certification as the Eastern Interconnection MOD-032, Requirement R4 Designee.
- During a transition period oversee the steady state and dynamic simulation base case data compilation and development.
- Oversee the ERAG assessment plan and coordinate assessment efforts with NERC Assessment Program staff. Determine the targeted ERAG assessment topic for 2020. Determine to method of assessment: analytical study, research effort, peer review.
- Make appropriate revisions, as necessary, to the ERAG Strategic Direction (i.e. anticipated new developments in MMWG process and system assessments).
- Develop and approve the ERAG activity budgets.

Multi-Regional Modeling Working Group 2020 Goals and Deliverables

- During a transition period of the Eastern Interconnection base case development MOD-032-1, Requirement 4 Designee period from ERAG to EIPC facilitate the completion of the steady state and dynamic simulation base case data compilation and development for the 2020 series of cases.
- Check and confirm that the dynamic model data passes all applicable checks and acceptance criteria.
- Incorporate dispatch information into the future and seasonal MMWG base cases so that the dispatches are more closely aligned with economic dispatch practices.
- Continue to improve the representations of the governor-turbine plant control models.
- 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.

ERAG System Assessments 2020 Goals and Deliverables

- Determine an appropriate topic of focus for the 2020 ERAG Assessment. In recent years, ERAG has conducted peer reviews on select topics in lieu of conducting assessments. Conduct the 2020 ERAG Assessment and prepare any associated documentation.
- 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.

Bulk Electric System Notification and Exception (BESnet) application and Exception Request (ERs)

NPCC supports maintenance of the BESnet application and the processing of the Regional BES Exception Requests (ERs), including periodic certifications that the basis for an Element being included or excluded in the BES through the Exception remains valid. No NPCC Exception Requests are due for recertification in 2020. Analysis of an Exception Request from a New Brunswick entity may extend into 2020.

2020 NERC Activities

NPCC will provide the Regional perspective with appropriate NPCC RAPA staff participation on selective NERC Technical Committees and key related NERC Subcommittees, Task Forces and Working Groups, including:

- Event Analysis Subcommittee (EAS)
- Inverter-Based Resource Performance Task Force (IRPTF)
- Performance Analysis Subcommittee (PAS)
  - Demand Response Availability Data System Working Group (DADSWG)
  - Battery Availability Data System Working Group (BADSWG)
  - Generating Availability Data System Working Group (GADSWG)
  - Misoperation Information Data Analysis System (MIDASWG)
  - Transmission Availability Data System Working Group (TADSWG)
- Reliability Assessment Subcommittee (RAS)
  - Probabilistic Assessment Working Group (PAWG)
- System Analysis and Modeling Subcommittee (SAMS)
  - Load Modeling Task Force (LMTF)
  - Power Plant Model Verification Task Force (PPMVTF)
  - Node Breaker Modeling Group (NBMG)
- System Protection and Control Subcommittee (SPCS)
- Synchronized Measurement Subcommittee (SMS)
- System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG)
- Battery and Storage Task Force (BASTF)

ERO – Executive Management Group (EMG) 2020 Activities

Provide analytic support for the ERO-EMG:

- Operations Leadership Team;
- Bulk Electric System Exception Process Working Group, under Organization Registration and Certification Group (ORCG);
- ERO-RAPA Group; and,
- Other activities as directed by the ERO-Executive Management Group.

2020 Goals and Key Deliverables

NPCC Task Force activities support 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.*"

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.

TFCP Reliability Assessment and Performance Analysis 2020 Goals and Deliverables

- Coordinate NPCC responses to the approved 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 the recommendations are addressed.
- Coordinate the development of additional NPCC Criteria as necessary and track any new and developing Regional NPCC Standards through the NPCC Regional Standards Committee.
- Monitor industry practices and make recommendations to the NPCC Regional Standards Committee regarding related NERC Standards.
- Oversee the NPCC Directory No. 1 Implementation Plan (Dated: September 30, 2015).
- Oversee the activities of the NPCC CP-8 Working Group.
- Evaluate and recommend RCC approval of NPCC Area Transmission Reviews.
- Evaluate and recommend RCC approval of NPCC Area Reviews of Resource Adequacy.
- Coordinate, monitor, review, and make recommendations on the retirement of existing in-service and/or implementation of proposed or modified Special Protection Systems Remedial Action Schemes.
- Coordinate the NPCC transition from SPS to RAS in accordance with PRC-012-2.
-
- Lead the NPCC Task Forces in conducting the review of the reliability and cost benefit of Directory No. 1, Design and Operation of the BPS.
- Support related reliability activities, including consideration of any requests for sub-regional assessments.
- Keep informed on studies and developments in neighboring systems which might impact NPCC reliability.
- 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 related NPCC documents.

TFSS Reliability Assessment and Performance Analysis 2020 Goals and Deliverables

- Review and recommend approval of Area Transmission Reviews.
- Review and classify new and modified Remedial Action Schemes.
- Review and Implement the NPCC A-10 Criteria.
- Perform annual review and update of the Major Project List.
- 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 Bulk Electric System risks as identified by the NERC Reliability Issues Steering Committee.

- Review existing NPCC Regional Criteria and procedures for validation of data used in power flow and dynamic simulations; propose changes to provide for adequate data validation.
- Perform investigation of Distributed Energy Resources modeling practices.
- Annually develop a library of power flow base cases and associated dynamic cases.
- Enable the annual review of the NPCC event replication procedure and ensure the preparedness of the NPCC Planning Coordinators to develop base cases for a required investigation of a major system event in or affecting NPCC and support the performance of event replication by benchmarking simulations against actual system performance.
- Work with software vendors and NERC to enhance the capability for dynamic simulations.
- Continue to investigate the use of dynamic load models for transient stability studies.
- Investigate the use of load monitoring equipment to aid in the benchmarking of dynamic load models used in transient stability studies.

Task Force on System Protection

The primary 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 NPCC protection systems.

TFSP Reliability Assessment and Performance Analysis 2020 Goals and Deliverables

- Assess proposed protection systems and Special Protection Systems/Remedial Action Schemes.
- Participate and/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.
- Participate in the ongoing development and submission of NPCC inputs/comments into the development of related NERC Reliability Standards.
- Monitor the NPCC metric on protection system Misoperation Risk Index Score calculations.
- Review mitigations and/or progress reports for Bulk Power System Risk Reduction Implementation.
- Provide support and technical input for related protection system risks as identified by the NERC Reliability Issues Steering Committee.
- Conduct review/development of related NPCC Directories.
- Consistent with the TFSP's scope, conduct joint meeting with other Regions to share best practices and experiences.
- Review ongoing changes to the North American Reliability Corporation Critical Infrastructure Protection Standards and evaluate impacts to Registered Entities Protection Systems, SCADA, and Monitoring Systems.

Task Force on Coordination of Operation

The NPCC Task Force on Coordination of Operation (TFCO) primarily facilitates the coordination of operations among the NPCC Reliability Coordinator areas and adjacent NERC Regions to enhance the reliability of the bulk power system.

TFCO Reliability Assessment and Performance Analysis 2020 Goals and Deliverables

- Prepare and conduct the spring and autumn NPCC System Operator Seminars.
- Develop and securely disseminate the annual compilation of "Facilities for Notification."
- Support and take part in the biennial, continent-wide Grid Security Exercise, including a review of the associated reports and Lessons Learned.
- Complete a triennial review of the individual RC Areas' restoration plans.
- 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.
- Conduct reviews of applicable NPCC Directories, Criteria, Guides and Procedures in accordance with their applicable review dates.
- Coordinate system awareness among NPCC Reliability Coordinators through periodic conference calls.
- Monitor the trends and impacts of the changing resource mix and the effects of the proliferation of the new resources on real-time operations, as well as behavior during and impacts on recovery and restoration plans.
- Provide assistance to the NERC Event Analysis Process and evaluate the operational applicability of the identified Lessons Learned.
- Review a biennial summary of operating tool failures and lessons learned for the preceding study period.
- Review and analyze the performance of Simultaneous Activation of Reserve (SAR) implementation following an event to enhance the process.

NPCC Regulatory/Governmental Affairs Advisory Group

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 reliability matters.

The Regulatory/Governmental Affairs Advisory Group activities indicated below are done in support of ERO Goal No. 3 "*Reduction of Known Risks to Reliability*" and ERO Goal No. 4 "*Identification and Assessment of Emerging Risks to Reliability*."

NPCC Regulatory/Governmental Affairs Advisory Group 2020 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, Distributed Energy Resource integration).
- 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 20% of its resources on these activities.

Resource Requirements

Personnel

- Decrease of 0.40 FTE represents reallocation of staff to situation awareness to address shift in focus areas.

Consultants and Contracts

- Increase in consultants and contracts expense is associated with increase in inherent risk and emerging risk reliability assessments.

Reliability Assessment and Performance Analysis Program

Funding sources and related expenses for the Reliability Assessment and Performance Analysis section of the 2019 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 2019 Budget & Projection, and 2020 Budget Reliability Assessment and Performance Analysis						
		2019 Budget	2019 Projection	Variance 2019 Projection v 2019 Budget Over(Under)	2020 Budget	Variance 2020 Budget v 2019 Budget Over(Under)
Funding						
ERO Funding						
	ERO Assessments	$ 3,332,686	$ 3,332,686	$ -	$ 3,210,055	$ (122,632)
	Penalty Sanctions	-	-	-	21,115	21,115
Total ERO Funding		**$ 3,332,686**	**$ 3,332,686**	**$ -**	**$ 3,231,169**	**$ (101,517)**
	Membership Dues	-	-	-	-	-
	Testing Fees	-	-	-	-	-
	Services & Software	-	-	-	-	-
	Workshops & Misc Revenue	-	-	-	-	-
	Interest & Investment Income	-	-	-	-	-
Total Funding (A)		**$ 3,332,686**	**$ 3,332,686**	**$ -**	**$ 3,231,169**	**$ (101,517)**
Expenses						
Personnel Expenses						
	Salaries	$ 1,135,264	$ 1,135,264	$ -	$ 1,006,128	$ (129,136)
	Payroll Taxes	69,027	69,027	-	64,023	(5,004)
	Benefits	219,655	219,655	-	218,787	(868)
	Retirement Costs	123,322	123,322	-	109,418	(13,904)
Total Personnel Expenses		**$ 1,547,268**	**$ 1,547,268**	**$ -**	**$ 1,398,356**	**$ (148,912)**
Meeting Expenses						
	Meetings & Conference Calls	$ 23,000	$ 23,000	$ -	$ 22,000	$ (1,000)
	Travel	216,200	216,200	-	216,200	-
Total Meeting Expenses		**$ 239,200**	**$ 239,200**	**$ -**	**$ 238,200**	**$ (1,000)**
Operating Expenses, excluding Depreciation						
	Consultants & Contracts	$ 430,000	$ 430,000	$ -	$ 533,000	$ 103,000
	Office Rent	-	-	-	-	-
	Office Costs	-	-	-	-	-
	Professional Services	-	-	-	-	-
	Computer & Equipment Leases	-	-	-	-	-
	Miscellaneous	-	-	-	-	-
Total Operating Expenses		**$ 430,000**	**$ 430,000**	**$ -**	**$ 533,000**	**$ 103,000**
	Total Direct Expenses	**$ 2,216,468**	**$ 2,216,468**	**$ -**	**$ 2,169,556**	**$ (46,912)**
Indirect Expenses		**$ 1,132,814**	**$ 1,132,814**	**$ -**	**$ 1,031,701**	**$ (101,113)**
Other Non-Operating Expenses		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)		**$ 3,349,282**	**$ 3,349,282**	**$ -**	**$ 3,201,257**	**$ (148,025)**
Change in Assets		**$ (16,596)**	**$ (16,596)**	**$ -**	**$ 29,913**	**$ 46,508**
Fixed Asset Additions (C)		**$ (16,596)**	**$ (16,596)**	**$ -**	**$ 29,913**	**$ 46,508**
TOTAL BUDGET (=B+C)		**$ 3,332,686**	**$ 3,332,686**	**$ -**	**$ 3,231,169**	**$ (101,517)**
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)	2019 Budget	2020 Budget	Increase (Decrease)
Total FTEs	0.10	0.10	0.00
Direct Expenses	$233,297	$219,862	($13,435)
Indirect Expenses	$18,634	$19,000	$366
Other Non-Operating Expenses	$0	$0	$0
Inc(Dec) in Fixed Assets	$569	$551	($18)
Total Funding Requirement	$252,500	$239,412	($13,088)

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:

- potential operational problems for the coming season are discussed,
- physical layouts and electrical characteristics of the NPCC and PJM Areas are discussed,
- application of NPCC Directory and NERC Standard requirements pertinent to operation are discussed,
- major industry issues that are important for system operators are discussed,
- significant disturbances are reviewed for lessons learned; and
- table-top drills and communication and coordination exercises are conducted.

The seminars promote camaraderie and better communication among system operators from the NPCC and PJM Reliability Coordinator (RC) Areas and the Nova Scotia Balancing Authority (BA) area. PJM RC has significant interaction with the NPCC RCs and system operators from PJM have been regular participants at past seminars. Examples of specific topics addressed at recent seminars include: 1) additions and impacts to operations of renewable resources, 2) the development of conditions and violations related to major system Blackouts, 3) human performance related to system operations, 4) cybersecurity threats and system operator concerns, 5) system restoration approaches and tie-ins to neighboring systems and 6) application of NPCC Simultaneous Activation of Reserve. Usually, control center visits are included as part of the seminar activities.

This Program also provides for:

- sharing of RC/BA existing training program and system simulator area content;
- verification and sharing of training methods;
- evaluation of training and simulator aids as they become available;
- opportunities to consolidate training among the NPCC RCs and BAs, which includes opportunities to share training material and training sessions; and
- exchange of information on internal methods of system operator training.

The training activities indicated below are done in support of ERO Goals No. 3 "*Reduction of Known Reliability Risks*" and No. 6 "*Effective and Efficient Operation*". Related contributing activities to these goals include "Working with industry forums, expand communication and encourage sharing of good industry practices for increasing Human Performance (HP) effectiveness", "Acquire, engage, develop, and retain highly qualified talent with requisite technical expertise to execute the ERO Enterprise's statutory functions" and "Strengthen coordination among NERC, Regional Entities with cross-border footprints, and North American stakeholders in support of ERO Enterprise reliability and security priorities."

Funding Drivers and Reliability Benefits

- System operators participating in the Seminars: 1) share their approaches to addressing 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 PJM 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 and participate in these seminars;
- Seminar attendees also receive Continuing Education Hours (CEHs) (normally 3 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; 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 system operator awareness and knowledge of the standards, criteria and procedures that are applied in real time operation;
- Provide more sharing of 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 and COM standards;
- NPCC will conduct two Standards and Compliance workshops in 2020, 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).

2020 Key Assumptions

In addition to the Spring and Fall Standards and Compliance workshops, NPCC regularly conducts System Operators seminars, , specifically designed with table top exercises, targeted breakout classroom sessions and presentations on current industry related activities, to provide for the most efficient exchange of information between the NPCC and Areas' training staff, 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 and Areas' training staff members. To supplement these seminars and workshops, NPCC may develop webinars that will focus on specific topics pertinent to developments related to system operations, compliance program implementation, standards development or technical issues.

The System Operator seminars involve system operators' participants from the NPCC RC/BA Areas and PJM, and are held in early May and early November.

Training, Education and Operator Certification 2020 Goals and Deliverables

- Prepare and conduct the 2020 Spring and Fall NPCC System Operator Seminars.
- Continue collaboration and sharing of the intended RC/BA approaches, experiences and materials to task identification and training development
- As needed, enhance 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 Standards PER-003-1 "*Operating Personnel Credentials"* and PER-005-2 "*Operations Personnel Training.*"
- Develop on-line operational training webinars that focus on specific topics pertinent to compliance program implementation, standards development or technical issues.
- Conduct Spring and Fall 2020 Standards and Compliance workshops addressing the development of NERC and Regional Reliability Standards and the implementation of the Compliance Monitoring and Enforcement Program (CMEP).

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

- No significant changes.

Training, Education, and Operator Certification Program

Funding sources and related expenses for the training, education, and operator certification section of the 2020 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
2019 Budget & Projection, and 2020 Budget
Training, Education, and Operator Certification

		2019 Budget	2019 Projection	Variance 2019 Projection v 2019 Budget Over(Under)	2020 Budget	Variance 2020 Budget v 2019 Budget Over(Under)
Funding						
ERO Funding						
	ERO Assessments	$ 184,943	$ 184,943	$ -	$ 171,524	$ (13,420)
	Penalty Sanctions	-	-	-	389	389
Total ERO Funding		**$ 184,943**	**$ 184,943**	**$ -**	**$ 171,912**	**$ (13,031)**
	Membership Dues	-	-	-	-	-
	Testing Fees	-	-	-	-	-
	Services & Software	-	-	-	-	-
	Workshops & Misc Revenue	67,500	67,500	-	67,500	-
	Interest & Investment Income	-	-	-	-	-
Total Funding (A)		**$ 252,443**	**$ 252,443**	**$ -**	**$ 239,412**	**$ (13,031)**
Expenses						
Personnel Expenses						
	Salaries	$ 18,600	$ 18,600	$ -	$ 11,793	$ (6,807)
	Payroll Taxes	1,513	1,513	-	939	(575)
	Benefits	6,805	6,805	-	5,652	(1,153)
	Retirement Costs	2,379	2,379	-	1,478	(900)
Total Personnel Expenses		**$ 29,297**	**$ 29,297**	**$ -**	**$ 19,862**	**$ (9,435)**
Meeting Expenses						
	Meetings & Conference Calls	$ 189,000	$ 189,000	$ -	$ 185,000	$ (4,000)
	Travel	15,000	15,000	-	15,000	-
Total Meeting Expenses		**$ 204,000**	**$ 204,000**	**$ -**	**$ 200,000**	**$ (4,000)**
Operating Expenses, excluding Depreciation						
	Consultants & Contracts	$ -	$ -	$ -	$ -	$ -
	Office Rent	-	-	-	-	-
	Office Costs	-	-	-	-	-
	Professional Services	-	-	-	-	-
	Computer & Equipment Leases	-	-	-	-	-
	Miscellaneous	-	-	-	-	-
Total Operating Expenses		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
	Total Direct Expenses	**$ 233,297**	**$ 233,297**	**$ -**	**$ 219,862**	**$ (13,435)**
Indirect Expenses		**$ 19,431**	**$ 19,431**	**$ -**	**$ 19,000**	**$ (431)**
Other Non-Operating Expenses		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)		**$ 252,728**	**$ 252,728**	**$ -**	**$ 238,862**	**$ (13,866)**
Change in Assets		**$ (285)**	**$ (285)**	**$ -**	**$ 551**	**$ 836**
Fixed Asset Additions (C)		**$ (285)**	**$ (285)**	**$ -**	**$ 551**	**$ 836**
TOTAL BUDGET (=B+C)		**$ 252,443**	**$ 252,443**	**$ -**	**$ 239,412**	**$ (13,031)**
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)	2019 Budget	2020 Budget	Increase (Decrease)
Total FTEs	5.00	5.40	0.40
Direct Expenses	$1,409,379	$1,450,129	$40,750
Indirect Expenses	$931,695	$1,026,001	$94,306
Other Non-Operating Expenses	$0	$0	$0
Fixed Asset Additions	$28,466	$29,747	$1,281
Total Funding Requirement	$2,369,540	$2,505,877	$136,337

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 an event does occur, it is critical to provide a forum for active coordination of reliability and operation among the NPCC Reliability Coordinator areas and neighboring NERC Regions and to use an event as a learning opportunity to enhance the reliability of the interconnected bulk power system through the lessons 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 "*Reduction of Known Risks to Reliability*" and ERO Goal No. 5 – "*Identification and Reduction of Cyber and Physical Security Risks."* Related contributing activities to Goal 3 include "Analyzing system performance, events, and relationships among data sources to identify risks and mitigation strategies and provide recommendations and lessons learned, including those that are lower impact, to discover potential reliability trends early in their lifecycles" and "Promoting the use of NERC cause codes to establish a common understanding of HP triggers, collect and evaluate trends in data, and develop metrics as needed." Contributing activities to Goal 5 include "Working closely with industry, NERC's Critical Infrastructure Protection Committee (CIPC), governmental agencies, the national labs, industry forums, trade associations and other stakeholders, promote leading security practices, information sharing and analysis, and resilience."

Event Analysis Program Description

NERC, Regions and the industry analyze events, identify the lessons to be learned, and conduct a formal cause code analysis.

The Event Analysis Program recognizes that many events which occur on the bulk power system beyond those identified through NERC Reliability Standard EOP-004-4, "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 implementing a "bottom-up" approach to an event review within the framework of the NERC Event Analysis Program, consistency, comparability, flexibility, quality 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 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 is accomplished by performing 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 voluntary effort, the entity, the Region and NERC staff will collaborate to assess the NERC Brief Report or Event Analysis Report and perform a formal cause code analysis, identifying a root cause and publish any pertinent lessons learned gathered from the event.

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 a more detailed and in-depth analysis. Consistent with risk-based approach, only concise and succinct reviews are desired for more minor events. ERO EAP delineates the expectations, roles and responsibilities of the registered entities, NPCC and NERC in a uniform review of system events by the industry and promotes a 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 analysis of the lesser events on the system, learning from these events and developing recommendations, risk of larger events can be mitigated.

NPCC staff works step-by-step with the registered entity throughout the total event analysis process, permitting the entity to assume the primary role in the development of the initial event analysis, lessons learned, which may benefit the industry, along with assisting and overseeing the Standards sufficiency review and cause coding process 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.

2020 Key Assumptions

- The monitoring of Lessons Learned will continue to be a major focus of NERC and NPCC in 2020, including:
    - continued reporting, for applicable qualifying eventsin the voluntary Event Analysis Program, of more detailed information on station equipment failure, per recommendation of the AC Substation Equipment Task Force, to solicit and collect this data, to aid in future analysis of station equipment failures and to identify trends that may be a threat to the reliability of the Bulk Electric System,
    - Introduction of a new EAP categories, implemented to capture the effect of "non-consequential" loss of inverter type resources and similarly DC ties between two separate asynchronous systems,
    - continued utilization of a revised Category 1h - EMS/Loss of monitoring or control at a Control Center events Brief Report template and Addendum, developed with the input of the EMS Working Group to ensure continuation of analysis of such events to improve information collection related to such events and associated analysis, taking into account the modifications to the mandatory EOP-004-4 reporting requirements thresholds.
- NERC will post updates to the Critical Infrastructure Protection Standards to address the outstanding FERC Directives and the remaining industry concerns that were not satisfactorily responded to by the version 5 Transition Advisory Group, including:
    - The new CIP-008 reporting requirements
    - The supply chain standards, which become mandatory July 2020
    - CIP modification SDT effort on virtualization
    - Updates to CIP-002 and CIP-003
- TFIST will address cloud computing initiatives, through technical consensus comments and ballot recommendations, specifically on the topics of:
    - Cloud computing work on BES Cyber Systems Information updates to CIP-004 and CIP-011
    - Continued evaluation of coordination between CIP standards and Federal Risk and Authorization Management Program (FedRAMP) - an assessment and authorization process which U.S. federal agencies have been directed by the Office of Management and Budget to ensure security is in place when accessing cloud computing products and services
- Resource allocation to this program area will support expanded Events Analysis activities; coordination with NERC's evolving E-ISAC capabilities; and physical and cyber security outreach efforts.

Situation Awareness 2020 Goals and Deliverables

- NPCC will provide the Regional perspective and support through NPCC Event Analysis staff participation on selective NERC Technical Committees and key related NERC Subcommittees, Task Forces and Working Groups, including the Event Analysis Subcommittee, the ERO – Event Analysis/Situational Awareness Group; and utilization of The Event Analysis Management System (TEAMS).
- Work directly with applicable NPCC Task Forces and Working Groups to provide an in-depth assessment of Lessons Learned unique to the NPCC Members and NPCC Criteria.
- Promote NPCC's Event Analysis group's process for sharing and dissemination of the detailed Event Analysis Report information among industry participants (Registered Entities).
- Incorporate the Lessons Learned from participation in the GridEx V wide-area exercise.

- 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 within NPCC. Notify the Reliability Coordinators 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, 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 staff.
- Coordination and communication with the NERC Bulk Power System Awareness group in preparation for and during ongoing significant events in the NPCC's footprint and participation in the ERO Enterprise-wide Situation Awareness activities. Monitor the status of the bulk power system through the NERC Situational Awareness-FERC, NERC, Regions version 3 (SAFNRv3) tool, a near real-time operating display for the United States portion of the Reliability Coordinators footprints of North America, an enhanced visualization tool, providing more timely and accurate assessments of current conditions affecting the BPS, thus enabling NERC's and Regions' obligation to maintain situational awareness and facilitation of timely communications and collaboration with key stakeholders .

Infrastructure Security Objectives

NPCC's critical infrastructure security objectives are defined within the scope of the NPCC Task Force on Infrastructure Security & Technology, and include, but are not limited to:

- Providing a forum for NPCC review of proposed and posted documents from the NERC Critical Infrastructure Protection Committee; 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 physical and cyber security outreach efforts, will supplement infrastructure security objectives and support the ERO Enterprise contributing activity of "Working closely with industry, NERC's Critical Infrastructure Protection Committee (CIPC), governmental agencies, the national labs, industry forums, trade associations and other stakeholders, promote leading

security practices, information sharing and analysis, and resilience." NPCC's Physical Security Working Group – an NPCC group of physical security experts formed to discuss, in a secure environment, emerging threats, trends and new security technologies and strategies utilized by NPCC registered entities for the protection of their facilities in the physical arena. The Working Group is tasked with developing approaches to physical security that will enhance the reliability and resiliency of the BPS and further address any physical security issues that could challenge efficient operation of the BPS, including pertinent items identified in the biennial RISC report, under Physical and Cyber Security Vulnerabilities. The Group will function as a clearinghouse for intelligence information received from Federal, State and Local partners and will disseminate such information received to NPCC registered entities. In addition, the Working Group shall develop, review, and provide regional input on various industry physical security initiatives, working groups, and task forces, as appropriate.

NPCC's 2020 infrastructure security goals and objectives, support ERO Goal No. 5 – "*Identification and Reduction of Cyber and Physical Risks*." 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 "Leverage engagement with registered entities to encourage effective security practices and controls."

Infrastructure Security 2020 Goals and Deliverables

- Monitor the reliable implementation of the Cyber Security Standards.
- Monitor the Homeland Security Information Network, E- ISAC, NERC Alerts and Canadian Information Sharing and share information with the NPCC CO-8 Working Group, NPCC PSWG and NPCC members' cyber security experts.
- 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 review of cross border emergency telecommunications to verify each Area can communicate with each other.
- Provide support and technical input for Task Force related Bulk Electric System risks as identified by the NERC Reliability Issues Steering Committee. TFIST and PSWG will conduct a thorough review, provide comments as necessary and act on posted materials as directed and applicable.
- Support the NERC CIPC Grid Exercise Working Group in GridEx VI planning and simulation.
- 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.

- 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 2020 Goals and Deliverables

NPCC's system operations security objectives are defined within the scope of the NPCC Task Force on Coordination of Operation and include, but are not limited 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 ensuring cyber security concerns are addressed.

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 15% of its resources on this activity.

Resource Requirements

Personnel

- Increase of 0.40 FTE represents reallocation of staff to address shift in focus areas.

Situation Awareness and Infrastructure Security Program

Funding sources and related expenses for the situation awareness and infrastructure security section of the 2020 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
2019 Budget & Projection, and 2020 Budget
Situation Awareness and Infrastructure Security

		2019 Budget	2019 Projection	Variance 2019 Projection v 2019 Budget Over(Under)	2020 Budget	Variance 2020 Budget v 2019 Budget Over(Under)
Funding						
ERO Funding						
	ERO Assessments	$ 2,366,685	$ 2,366,685	$ -	$ 2,484,879	$ 118,195
	Penalty Sanctions	-	-	-	20,998	20,998
Total ERO Funding		**$ 2,366,685**	**$ 2,366,685**	**$ -**	**$ 2,505,877**	**$ 139,193**
	Membership Dues	-	-	-	-	-
	Testing Fees	-	-	-	-	-
	Services & Software	-	-	-	-	-
	Workshops & Misc Revenue	-	-	-	-	-
	Interest & Investment Income	-	-	-	-	-
Total Funding (A)		**$ 2,366,685**	**$ 2,366,685**	**$ -**	**$ 2,505,877**	**$ 139,193**
Expenses						
Personnel Expenses						
	Salaries	$ 832,408	$ 832,408	$ -	$ 924,110	$ 91,702
	Payroll Taxes	57,432	57,432	-	61,713	4,281
	Benefits	201,196	201,196	-	202,020	824
	Retirement Costs	89,043	89,043	-	99,986	10,943
Total Personnel Expenses		**$ 1,180,079**	**$ 1,180,079**	**$ -**	**$ 1,287,829**	**$ 107,750**
Meeting Expenses						
	Meetings & Conference Calls	$ 10,000	$ 10,000	$ -	$ 8,000	$ (2,000)
	Travel	89,300	89,300	-	94,300	5,000
Total Meeting Expenses		**$ 99,300**	**$ 99,300**	**$ -**	**$ 102,300**	**$ 3,000**
Operating Expenses, excluding Depreciation						
	Consultants & Contracts	$ 130,000	$ 130,000	$ -	$ 60,000	$ (70,000)
	Office Rent	-	-	-	-	-
	Office Costs	-	-	-	-	-
	Professional Services	-	-	-	-	-
	Computer & Equipment Leases	-	-	-	-	-
	Miscellaneous	-	-	-	-	-
Total Operating Expenses		**$ 130,000**	**$ 130,000**	**$ -**	**$ 60,000**	**$ (70,000)**
	Total Direct Expenses	**$ 1,409,379**	**$ 1,409,379**	**$ -**	**$ 1,450,129**	**$ 40,750**
Indirect Expenses		**$ 971,538**	**$ 971,538**	**$ -**	**$ 1,026,001**	**$ 54,463**
Other Non-Operating Expenses		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)		**$ 2,380,918**	**$ 2,380,918**	**$ -**	**$ 2,476,130**	**$ 95,212**
Change in Assets		**$ (14,233)**	**$ (14,233)**	**$ -**	**$ 29,747**	**$ 43,980**
Total Funding (A) Requirement		**$ 2,395,151**	**$ 2,395,151**	**$ -**	**$ 2,446,383**	**$ 51,232**
Fixed Asset Additions						
	Computer & Software CapEx	-	-	-	-	-
	Furniture & Fixtures CapEx	-	-	-	-	-
	Equipment CapEx	-	-	-	-	-
	Leasehold Improvements	-	-	-	-	-
	Allocation of Fixed Assets	(14,233)	(14,233)	-	29,747	43,980
Fixed Asset Additions (C)		**(14,233)**	**(14,233)**	**-**	**29,747**	**43,980**
TOTAL BUDGET (=B+C)		2,366,685	2,366,685	-	2,505,877	139,193
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)		**$ (0)**	**$ (0)**	**$ -**	**$ 0**	**$ 0**

Administrative Services

Administrative Services Program Resources (in whole dollars)	Direct Expenses			FTEs		
	2019 Budget	2020 Budget	Increase (Decrease)	2019 Budget	2020 Budget	Increase (Decrease)
Technical Committees and Members Forum	$74,483	$75,793	$1,310	0.50	0.50	0.00
General and Administrative [2]	$3,391,903	$3,874,453	$482,550	2.50	2.73	0.23
Legal and Regulatory	$612,934	$761,007	$148,073	1.00	2.00	1.00
Information Technology	$1,083,781	$1,314,119	$230,339	2.00	2.00	0.00
Human Resources	$156,946	$158,731	$1,785	1.00	1.00	0.00
Finance and Accounting	$642,798	$703,291	$60,493	2.00	2.00	0.00
Total Administrative Services[1]	$5,962,845	$6,887,395	$924,550	9.00	10.23	1.23

[1] NPCC's 2020 Administrative Services Direct Expenses and Fixed Assets total $6,887,395, of which $409,450 is allocated to NPCC's Criteria Services division, which is a non-statutory function. As a result of the allocation to the Criteria Services division, the Administrative Expenditures included in the 2020 statutory budget are $6,477,945 which is an increase of $743,865 from the 2019 budget of $5,734,080.

[2] Succession implementation costs of $444,540 included in General and Administrative Direct Expenses will be funded from Board approved Business Continuity Reserves and will not impact assessments.

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 2020 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
2019 Budget & Projection, and 2020 Budget
ADMINISTRATIVE SERVICES

		2019 Budget	2019 Projection	Variance 2019 Projection v 2019 Budget Over(Under)	2020 Budget	Variance 2020 Budget v 2019 Budget Over(Under)
Funding						
ERO Funding						
	ERO Assessments	$ (100,108)	$ (100,108)	$ -	$ (593,855)	$ (493,746)
	Penalty Sanctions	-	-	-	-	-
Total ERO Funding		**$ (100,108)**	**$ (100,108)**	**$ -**	**$ (593,855)**	**$ (493,746)**
	Membership Dues	-	-	-	-	-
	Testing Fees	-	-	-	-	-
	Services & Software	-	-	-	-	-
	Workshops & Misc Revenue	-	-	-	-	-
	Interest & Investment Income	-	-	-	55,800	55,800
Total Funding (A)		**$ (100,108)**	**$ (100,108)**	**$ -**	**$ (538,055)**	**$ (437,946)**
Expenses						
Personnel Expenses						
	Salaries	$ 2,147,254	$ 2,126,254	$ (21,000)	$ 2,433,049	$ 285,794
	Payroll Taxes	107,437	105,437	(2,000)	126,595	19,158
	Benefits	493,115	478,115	(15,000)	674,649	181,534
	Retirement Costs	296,142	294,142	(2,000)	313,571	17,429
Total Personnel Expenses		**$ 3,043,948**	**$ 3,003,948**	**$ (40,000)**	**$ 3,547,864**	**$ 503,916**
Meeting Expenses						
	Meetings & Conference Calls	$ 162,750	$ 162,750	$ -	$ 162,750	$ -
	Travel	135,100	135,100	-	129,100	(6,000)
Total Meeting Expenses		**$ 297,850**	**$ 297,850**	**$ -**	**$ 291,850**	**$ (6,000)**
Operating Expenses, excluding Depreciation						
	Consultants & Contracts	$ 95,000	$ 95,000	$ -	$ 361,000	$ 266,000
	Office Rent	820,700	820,700	-	832,700	12,000
	Office Costs	676,347	676,347	-	685,981	9,634
	Professional Services	978,000	978,000	-	947,000	(31,000)
	Computer & Equipment Leases	-	-	-	-	-
	Miscellaneous	51,000	51,000	-	51,000	-
Total Operating Expenses		**$ 2,621,047**	**$ 2,621,047**	**$ -**	**$ 2,877,681**	**$ 256,634**
	Total Direct Expenses	**$ 5,962,845**	**$ 5,922,845**	**$ (40,000)**	**$ 6,717,395**	**$ 754,550**
Indirect Expenses		**$ (6,217,845)**	**$ (6,217,845)**	**$ -**	**$ (6,272,855)**	**$ (55,010)**
Other Non-Operating Expenses		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)		**$ (255,000)**	**$ (295,000)**	**$ (40,000)**	**$ 444,540**	**$ 699,540**
Change in Assets		**$ 154,892**	**$ 194,892**	**$ 40,000**	**$ (982,595)**	**$ (1,137,486)**
Fixed Asset Additions (C)		**$ 255,000**	**$ 255,000**	**$ -**	**$ -**	**$ (255,000)**
TOTAL BUDGET (=B+C)		**$ -**	**$ (40,000)**	**$ (40,000)**	**$ 444,540**	**$ 444,540**
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)		**$ (100,108)**	**$ (60,108)**	**$ 40,000**	**$ (982,595)**	**$ (882,486)**

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.

2020 Key Assumptions

- NPCC's standing committee and subgroup structure for effective stakeholder involvement will continue in 2020.
- 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 2020.
- 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 2020 Goals and Deliverables

- The 2020 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 2020 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

- No significant changes.

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

- During 2020 an executive search will be conducted in order to identify a successor CEO to transition into that role by vote of the Membership at its Annual Meeting to become effective January 1, 2021. The incumbent President and CEO has identified a planned retirement during the first quarter of 2021. The expectation is that the identified successor will join NPCC by early November or December, 2020 in an executive leadership capacity. Costs related to the executive search efforts and succession plan implementation will be funded from the existing Business Continuity Reserve, identified by the NPCC Board of Directors in 2017 and approved at varying intervals within 2020 by the Board for reserve release. Therefore, 2020 assessments will not be impacted by these succession-related expenses.

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, consistent with ERO Goal 6. In support of ERO Goal 4., 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 plans to hire one FTE in the Legal and Regulatory program in 2020. A paralegal/legal assistant will support General Counsel and add to the overall efficiency of the organization. This addition is partially offset by a projected decrease in professional fees.

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 2020 Business Plan and Budget assumes agreed-upon ERO Enterprise applications will be available and includes only NPCC costs for Region specific support needs.

2020 Key Assumptions

- Continue to maintain the compliance portal through collaboration with other Regional Entities and NERC (CUG), while transitioning to the ERO Enterprise CMEP IT Tool (Align).
- 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.

2020 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:

- Continue to expand the utilization of the document management system throughout the company.
- Constantly review and evaluate security measures taken to reduce breach of security risks.

- Ensure all information systems are functional and secure, and that all applications running on those systems meet business requirements for performance, availability, and security.
- 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.
- Upgrade various hardware and equipment.

Resource Requirements

Personnel

- NPCC anticipates no need to hire additional personnel in this program area in 2020.

Fixed Assets

- Capital expenditures planned for 2020 include the continuing implementation and enhancement of the document management system and equipment upgrades.

Human Resources

Program Scope and Functional Description

NPCC has assembled an exceptional team of highly qualified employees to carry out its activities. 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

- No significant changes.

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.

2020 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

- No significant changes.

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 2017 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 2017 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 ISOs/BAAs within NPCC as the designees for the load serving entities (LSEs) 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 ISOs/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 net energy for load (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 _% 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 _% 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 _% 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 BAA's total average percentage of enforcement activities. The portion allocated to the U.S. BAA's 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.

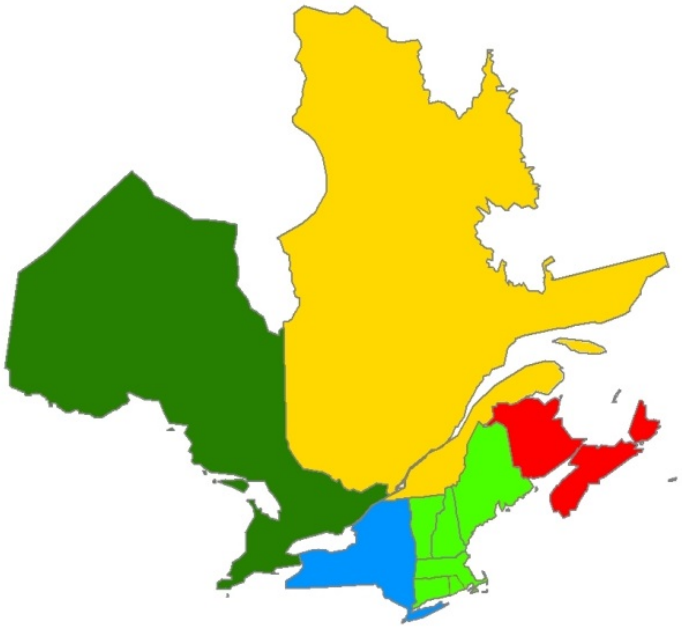
Any penalty monies received from NPCC registered entities within the U.S. by June 30th of the year preceding the business plan and budget year are then allocated among the NPCC program areas based on their FTE ratio and between the U.S. BAAs based on their relative NELs, and then added to the total compliance 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 Québec 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
2020 Business Plan and Budget



Section B – Supplemental Financial Information

Reserve Balance

Table B-1 Reserve Balance

Working Capital and Operating Reserve Analysis 2019-2020
REGIONAL ENTITY DIVISION

	Total Reserve	Operating Reserve	Working Capital	Business Continuity
Beginning Total Reserve, December 31, 2018	4,969,944	2,713,006	1,316,938	940,000
Plus: 2019 ERO Funding (from LSEs or designees)	15,003,411	15,003,411		
Plus: 2019 Other funding sources	67,500	67,500		
Less: 2019 Projected expenses & capital expenditures	(15,618,891)	(15,618,891)		
Projected Total Reserve, December 31, 2019	**4,421,964**	**2,165,026**	**1,316,938**	**940,000**
Desired Total Reserve, December 31, 2020	**3,402,353**	1,523,478 [1]	1,383,415 [2]	495,460 [3]
Less: Projected Total Reserve, December 31, 2019	(4,421,964)	(2,165,026)	(1,316,938)	(940,000)
Increase(decrease) in assessments to achieve desired Total Reserve	**(1,019,611)**	(641,548)	66,477	(444,540)

2020 Expenses and Capital Expenditures	16,601,647
Less: Penalty Sanctions [4]	(120,000)
Less: Other Funding Sources	(123,300)
Less: Release of Business Continuity Reserve Funds [3]	(444,540)
Adjustment to Working Capital to achieve desired Total Reserve balance [2]	66,477
Adjustment to Operating Reserve to achieve desired Total Reserve balance [1]	(641,548)
2020 Assessment	**15,338,737**

[1] Operating Reserve within a range from 8.33% to 25.00% of Budget. $1,523,478 represents 9.18% of the 2020 budget of $16,601,647
[2] Working Capital equal to 8.33% of Budget. $1,383,415 represents 8.33% of the 2020 budget of $16,601,647
[3] Business Continuity Reserve (BCR) established in 2017 as approved by the NPCC Board of Directors to fund Succession Planning related expenses.
[4] Represents collections July 1, 2018 to June 30, 2019.

Explanation of Changes in Reserve Policy from Prior Year

There was no change to the existing Working Capital and Operating Reserve Policy. A separate Business Continuity Reserve (BCR) in the amount of $1,000,000 (allocated between the Regional Entity and Criteria Services divisions) was established in 2017 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 drawn upon as subsequently brought before the Board of Directors for approval of release of funds in association with President & CEO succession related activities associated with the planned or a sudden retirement, as well as other sudden changing workforce staffing requirements which could be brought about by coincident multiple staff retirements.

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 2020 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, 2019 are to be used to offset assessments in the 2020 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, 2018 through June 30, 2019 are listed below. Penalty monies received from July 1, 2019 through June 30, 2020 will be used to offset U.S. load serving entity designee assessments in the 2021 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, 2019	Date Received	Amount Received
	7/16/2018	$ 120,000.00
Total Penalties Received		**$ 120,000.00**

Table B-3 Supplemental Funding

Outside Funding Breakdown By Program (excluding ERO Assessments & Penalty Sanctions)	Budget 2019	Projection 2019	Budget 2020	Variance 2020 Budget v 2019 Budget
Reliability Standards				
Total	$ -	$ -	$ -	$ -
Compliance Monitoring, Enforcement & Org. Registration				
	$ -	$ -	$ -	$ -
	-	-	-	-
Total	$ -	$ -	$ -	$ -
Reliability Assessment and Performance Analysis				
	$ -	$ -	$ -	$ -
	-	-	-	-
Total	$ -	$ -	$ -	$ -
Training and Education				
Workshops	$ 67,500	$ 67,500	$ 67,500	$ -
Total	$ 64,000	$ 67,500	$ 67,500	$ -
Situation Awareness and Infrastructure Security				
	$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	$ -
Technical Committees and Member Forums				
	$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	$ -
Administrative Services Programs				
Interest & Investment Income	$ -	$ -	$ 55,800	$ 55,800
Total	$ -	$ -	$ 55,800	$ 55,800
Total Outside Funding	$ 64,000	$ 67,500	$ 123,300	$ 55,800

Explanation of Significant Variances –2020 Budget versus 2019 Budget

- NPCC estimates interest & investment income of $55,800 in 2020 from investment of reserves in a 100% U.S. Treasury money market fund, which will offset 2020 assessments.

Table B-4 Personnel Expenses

Personnel Expenses	Budget 2019	Projection 2019	Budget 2020	Variance 2020 Budget v 2019 Budget	Variance %
Salaries					
Salary	$ 7,298,280	$ 7,298,280	$ 7,664,262	$ 365,982	5.0%
Employment Agency Fees	$ 10,000	$ 10,000	$ 16,000	$ 6,000	60.0%
Temporary Office Services	$ 24,000	$ 24,000	$ 24,000	$ -	0.0%
Total Salaries	$ 7,332,280	$ 7,332,280	$ 7,704,262	$ 371,982	5.1%
Total Payroll Taxes	$ 449,994	$ 449,994	$ 479,019	$ 29,026	6.5%
Benefits					
Education Reimbursement	$ 32,000	$ 32,000	$ 27,500	$ (4,500)	-14.1%
Training and Seminars	$ 58,290	$ 58,290	$ 83,580	$ 25,290	43.4%
Medical Insurance	$ 901,783	$ 901,783	$ 1,168,854	$ 267,071	29.6%
Life-LTD-STD Insurance	$ 94,804	$ 94,804	$ 110,889	$ 16,085	17.0%
Worker's Compensation	$ 20,000	$ 20,000	$ 32,000	$ 12,000	60.0%
Vacation	$ 506,201	$ 506,201	$ 504,062	$ (2,139)	-0.4%
Relocation	$ -	$ -	$ -	$ -	-
Total Benefits	$ 1,613,078	$ 1,613,078	$ 1,926,885	$ 313,806	19.5%
Retirement					
Pension Contribution	$ -	$ -	$ -	$ -	-
Employee Savings Plan	$ 741,511	$ 741,511	$ 770,950	$ 29,440	4.0%
Savings Admin	$ 36,000	$ 36,000	$ 36,000	$ -	0.0%
Deferred Compensation	$ 76,000	$ 76,000	$ 76,000	$ -	0.0%
Total Retirement	$ 853,511	$ 853,511	$ 882,950	$ 29,440	3.4%
Total Personnel Costs	**$ 10,248,862**	**$ 10,248,862**	**$ 10,993,117**	**$ 744,254**	**7.3%**
FTEs	38.86	38.86	41.09	2.23	5.7%
Cost per FTE					
Salaries	$ 188,685	$ 188,685	$ 187,497	$ (1,187)	-0.6%
Payroll Taxes	$ 11,580	$ 11,580	$ 11,658	$ 78	0.7%
Benefits	$ 41,510	$ 41,510	$ 46,894	$ 5,384	13.0%
Retirement	$ 21,964	$ 21,964	$ 21,488	$ (476)	-2.2%
Total Cost per FTE	**$ 263,738**	**$ 263,738**	**$ 267,538**	**$ 3,799**	**1.4%**

Explanation of Significant Variances –2020 Budget versus 2019 Budget

- Increase in Training and Seminars is due to an increase per employee training budget.
- Medical insurance increase reflects a premium increase of 8%. Additionally, less employees are waiving NPCC coverage for that of a prior employer.
- Personnel expenses include some succession planning related costs that will be funded through business continuity reserves and do not impact assessments.

Table B-5 Meeting Expense

Meeting Expenses	Budget 2019	Projection 2019	Budget 2020	Variance 2020 Budget v 2019 Budget	Variance %
Meetings	$ 370,750	$ 370,750	$ 361,750	$ (9,000)	-2.4%
Travel	$ 845,900	$ 845,900	$ 845,900	$ -	0.0%
Conference Calls	$ 36,000	$ 36,000	$ 36,000	$ -	0.0%
Total Meeting Expenses	**$ 1,252,650**	**$ 1,252,650**	**$ 1,243,650**	**$ (9,000)**	**-0.7%**

Explanation of Significant Variances – 2020 Budget versus 2019 Budget

- None.

Table B-6 Consultants and Contracts

Consultants	Budget 2019	Projection 2019	Budget 2020	Variance 2020 Budget v 2019 Budget	Variance %
Consultants					
Reliability Standards	$ -	$ -	$ -	$ -	-
Compliance Enforcement and Organization Registration and Certification	$ -	$ -	$ -	$ -	-
Reliability Assessment and Performance Analysis	$ -	$ -	$ -	$ -	-
Training and Education	$ -	$ -	$ -	$ -	-
Situation Awareness and Infrastructure Security	$ -	$ -	$ -	$ -	-
Member Forums	$ -	$ -	$ -	$ -	-
General and Administrative	$ -	$ -	$ 279,000	$ 279,000	-
Legal and Regulatory	$ -	$ -	$ -	$ -	-
Information Technology	$ -	$ -	$ -	$ -	-
Human Resources	$ -	$ -	$ -	$ -	-
Accounting and Finance	$ -	$ -	$ -	$ -	-
Consultants Total	**$ -**	**$ -**	**$ 279,000**	**$ 279,000**	**-**

Contracts	Budget 2019	Projection 2019	Budget 2020	Variance 2020 Budget v 2019 Budget	Variance %
Reliability Standards	$ 10,000	$ 10,000	$ 20,000	$ 10,000	100.0%
Compliance Enforcement and Organization Registration and Certification	$ 1,357,150	$ 1,357,150	$ 1,097,150	$ (260,000)	-19.2%
Reliability Assessment and Performance Analysis	$ 430,000	$ 430,000	$ 533,000	$ 103,000	24.0%
Training and Education	$ -	$ -	$ -	$ -	-
Situation Awareness and Infrastructure Security	$ 130,000	$ 130,000	$ 60,000	$ (70,000)	-53.8%
Member Forums	$ -	$ -	$ -	$ -	-
General and Administrative	$ 88,000	$ 88,000	$ 75,000	$ (13,000)	-14.8%
Legal and Regulatory	$ -	$ -	$ -	$ -	-
Information Technology	$ -	$ -	$ -	$ -	-
Human Resources	$ -	$ -	$ -	$ -	-
Accounting and Finance	$ 7,000	$ 7,000	$ 7,000	$ -	0.0%
Contracts Total	**$ 2,022,150**	**$ 2,022,150**	**$ 1,792,150**	**$ (230,000)**	**-11.4%**
Total Consultants and Contracts	**$ 2,022,150**	**$ 2,022,150**	**$ 2,071,150**	**$ 49,000**	**2.4%**

Explanation of Significant Variances –2020 Budget versus 2019 Budget

- During 2020 an executive search will be conducted in order to identify a successor CEO. Consulting costs related to the search efforts will be funded from the existing Business Continuity Reserves. 2020 assessments will not be impacted by these succession-related expenses.
- 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 2019	Projection 2019	Budget 2020	Variance 2020 Budget v 2019 Budget	Variance %
Office Rent	$ 650,000	$ 650,000	$ 650,000	$ -	0.0%
Utilities	$ 45,000	$ 45,000	$ 47,000	$ 2,000	4.4%
Maintenance	$ 37,000	$ 37,000	$ 37,000	$ -	0.0%
Security	$ 2,700	$ 2,700	$ 2,700	$ -	0.0%
Real Estate Taxes	$ 86,000	$ 86,000	$ 96,000	$ 10,000	11.6%
Total Office Rent	**$ 820,700**	**$ 820,700**	**$ 832,700**	**$ 12,000**	**1.5%**

Explanation of Significant Variances –2020 Budget versus 2019 Budget

- None.

Table B-8 Office Costs

Office Costs	Budget 2019	Projection 2019	Budget 2020	Variance 2020 Budget v 2019 Budget	Variance %
Telephone	$ 88,720	$ 88,720	$ 88,720	$ -	0.0%
Internet Expense	$ 82,740	$ 82,740	$ 74,340	$ (8,400)	-10.2%
Office Supplies	$ 33,000	$ 33,000	$ 33,000	$ -	0.0%
Computer Supplies and Maintenance	$ 397,387	$ 397,387	$ 424,921	$ 27,534	6.9%
Subscriptions & Publications	$ 13,500	$ 13,500	$ 14,000	$ 500	3.7%
Dues	$ 3,400	$ 3,400	$ 3,400	$ -	0.0%
Postage	$ 1,200	$ 1,200	$ 1,200	$ -	0.0%
Express Shipping	$ 10,000	$ 10,000	$ 6,000	$ (4,000)	-40.0%
Copying	$ 26,400	$ 26,400	$ 26,400	$ -	0.0%
Reports	$ 8,000	$ 8,000	$ 2,000	$ (6,000)	-75.0%
Stationary and Office Forms	$ 2,000	$ 2,000	$ 2,000	$ -	0.0%
Equipment Repair/Service Contracts	$ -	$ -	$ -	$ -	-
Bank Charges	$ 10,000	$ 10,000	$ 10,000	$ -	0.0%
Sales and Use Tax	$ -	$ -	$ -	$ -	-
Merchant Credit Card Fees	$ -	$ -	$ -	$ -	-
Presentation and Publicity	$ -	$ -	$ -	$ -	-
Total Office Costs	**$ 676,347**	**$ 676,347**	**$ 685,981**	**$ 9,634**	**1.4%**

Explanation of Significant Variances –2020 Budget versus 2019 Budget

- Total Office costs are expected to remain relatively flat.

Table B-9 Professional Services

Professional Services	Budget 2019	Projection 2019	Budget 2020	Variance 2020 Budget v 2019 Budget	Variance %
BOT Fee	$ 346,000	$ 346,000	$ 332,000	$ (14,000)	-4.0%
BOT Search Fee	$ -	$ -	$ -	$ -	-
Legal - Reorganization	$ -	$ -	$ -	$ -	-
Accounting & Auditing Fees	$ 300,000	$ 300,000	$ 310,000	$ 10,000	3.3%
Legal Fees - Other	$ 262,000	$ 262,000	$ 235,000	$ (27,000)	-10.3%
Insurance - Commercial	$ 70,000	$ 70,000	$ 70,000	$ -	0.0%
Total Services	**$ 978,000**	**$ 978,000**	**$ 947,000**	**$ (31,000)**	**-3.2%**

Table B-10 Miscellaneous

Miscellaneous Expense	Budget 2019	Projection 2019	Budget 2020	Variance 2020 Budget v 2019 Budget	Variance %
Miscellaneous Expense	$ 51,000	$ 51,000	$ 51,000	$ -	0.0%
Total Miscellaneous Expense	**$ 51,000**	**$ 51,000**	**$ 51,000**	**$ -**	**0.0%**

Table B-11 Other Non-Operating Expenses

Other Non-Operating Expenses	Budget 2019	Projection 2019	Budget 2020	Variance 2020 Budget v 2019 Budget	Variance %
Interest Expense	$ -	$ -	$ -	$ -	-
Office Relocation	$ -	$ -	$ -	$ -	-
Total Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**-**

Table B-12 Fixed Assets

Fixed Asset Additions	Budget 2019	Projection 2019	Budget 2020	Variance 2020 Budget v 2019 Budget	Variance %
Equipment CapEx	$ -	$ -	$ -	$ -	-
Computer & Software CapEx	$ 170,000	$ 170,000	$ 170,000	$ -	0.0%
Furniture & Fixtures CapEx	$ -	$ -	$ -	$ -	-
Leasehold Improvements	$ -	$ -	$ -	$ -	-
Allocation of Fixed Assets	$ -	$ -	$ -	$ -	-
Total Fixed Asset Additions	**$ 170,000**	**$ 170,000**	**$ 170,000**	**$ -**	**0.0%**

Explanation of Significant Variances –2020 Budget versus 2019 Budget

- Capital expenditures planned for 2020 include the continuing implementation of the document management system and equipment upgrades.

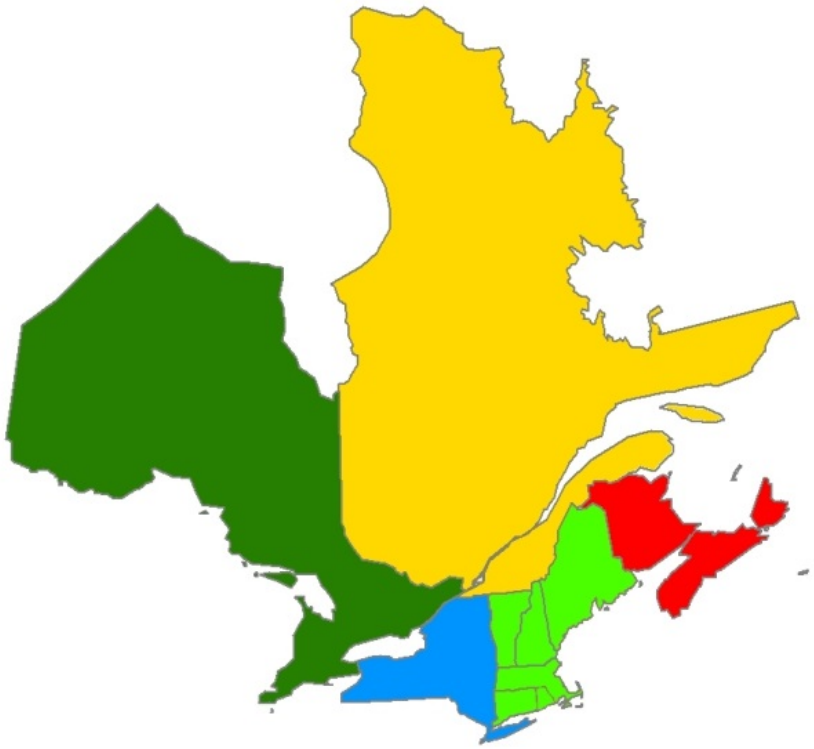
Table B-13 2020 and 2021 Projections

Table to be Inserted

Assumptions

Section C — Criteria Services Division Activities

2020 Business Plan and Budget



Section C – Criteria Services Division Activities

Criteria Services Division (in whole dollars)	2019 Budget	2020 Budget	Increase (Decrease)
Total FTEs	2.14	2.16	0.02
Total Direct Expenses	$662,756	$709,217	$46,462
Total Indirect Expenses	$398,765	$409,450	$10,685
Other Non-Operating Expenses	$0	$0	$0
Working Capital and Operating Reserves Requirement	($32,655)	($79,265)	($46,611)
Fixed Asset Additions	$30,000	$30,000	$0
Funding Requirement	$1,058,866	$1,069,402	$10,536

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 new or revised Regionally-specific, more stringent reliability criteria and supporting guideline or procedural documents. The requirements in NPCC Reliability Criteria apply only to those facilities defined as NPCC Bulk Power System elements through the performance based methodology identified in the NPCC Document A-10, "Classification of Bulk Power System Elements."

In accordance with the NERC Rules of Procedure (RoP) Section 313, Regional Entities may develop Regional Criteria necessary to implement, augment, or facilitate compliance with NERC Reliability Standards. These Regional Criteria may also be utilized to address issues not within the scope or jurisdiction of FERC as outlined in Section 215 of the Federal Power Act, such as resource adequacy. Regional Criteria may also address Canadian Provincial reliability issues, and may include specific operating or planning parameters, guides, agreements, protocols or other documents used to enhance the reliability of the Bulk Power System in the Region. These documents typically provide benefits by promoting more consistent implementation of the NERC Reliability Standards within the Region. These documents are not NERC Reliability Standards, Regional Reliability Standards, or Regional Variances, and therefore are not enforceable under the authority delegated by NERC pursuant to delegation agreements.

As NERC Reliability Standards are revised or new standards are developed, NPCC performs reviews of any associated Regional Criteria for possible impact.

For 2020 and beyond, the potential reliability impacts of increased penetration of Distributed Energy Resources (DER, e.g. solar and wind), and changing fuel mixes warrant further consideration. The Criteria Services Division has a unique opportunity to review these issues and develop criteria, guideline, and procedural documents for DER which may be outside of the jurisdiction of FERC and NERC Reliability Standards. Participation of the entities responsible for development of DER renewable resources to develop reliability documents will become increasingly important over time. Outreach, collaboration, and coordination of topics related to DER will enable NPCC to develop guidelines allowing more effective integration of these resources.

Increasing resilience of the BPS through alternative approaches to standards development using potential NPCC criteria, guidelines, and whitepapers will also be continually reviewed by NPCC's body of subject matter experts.

Membership and Governance

Full members, in accordance with NPCC's Amended and Restated Bylaws, are subject to compliance with Regionally-specific criteria 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.

Under Criteria Services NPCC will identify for membership, those entities involved in emerging technologies to assure that those entities that have an impact on Bulk Electric System reliability are included in appropriate NPCC activities.

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 2020 Assumptions and Cost Impacts

The Criteria Services division activities are expected to remain stable or slightly increase throughout 2020 depending on reliability need.

- 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.

2020 Primary Goals and Objectives

- Continue with the development and maintenance of a set of NPCC Directories which augment or add specificity to 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 NPCC 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.
    - Directory No. 12 "Automatic Underfrequency Load Shedding Requirements" will be retired in 2020 upon approval of PRC-006-NPCC-2 "Automatic Underfrequency Load Shedding" Regional Standard
- Identify opportunities to develop criteria, procedures or guideline documents to address reliability related matters with DER.
- Identify opportunities to address improvements in BES resilience with NPCC processes and documentation.
- Continually review the need to 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 augment and are not 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.
    -
    - 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 augment, add specificity, or address issues not covered in the NERC Reliability Standards as mandated by the NERC Rules of Procedure. The conversion of NPCC's reliability 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 requirements

and "standards 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 2020, 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 continue to be applied to the existing Directories to make them more consistent with the format of NERC standards. As NERC standards improve, the need for NPCC Directories and the amount of criteria contained therein may decrease over time, however in the interim, significant review is necessary to ensure the criteria remain consistent 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.

Additionally, as NERC Reliablity Standards are developed, associated Directories will be reviewed for continued need. This review will identify the incremental reliability enhancement the Directory's criteria will yield, determine if the enhancement is sufficient to warrant retention and if so, are there any potential cost effective alternatives that may exist to achieve that enhanced level of reliablity.

NPCC Operations and Planning Directories

The following Directories are envisioned to remain active for 2020.

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, 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 2019.

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 lead the review and revision of this Directory in 2018. The Directory was re-formatted to be consistent with the style of NERC standards.

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.

NPCC Criteria Compliance and Enforcement Program (CCEP)

The NPCC Criteria Services division supports the reliable operation of the NPCC Bulk Power System (BPS) through implementation of the NPCC Criteria Compliance Program (CCEP). This program monitors, assesses, and enforces compliance on a subset of the regionally specific, more stringent NPCC Criteria that are unique to the NPCC BPS and are not duplicative of the NERC Reliability Standards. The physical characteristics and topology of the transmission system within the Region require that certain aspects of criteria be monitored for compliance.

The Criteria Services division and the NPCC Compliance Committee (CC) administer the CCEP. The CC is a stakeholder body consisting of NPCC Members and is structured by the seven sectors that appear in the NPCC Bylaws.

Noncompliance to NPCC Criteria is not subject to monetary sanctions and results in a notification of noncompliance to the Chief Executive Officer of the appropriate Full Member.

The CCEP program is described in document CCEP-1, *NPCC Criteria Compliance and Enforcement Program (CCEP) Process Document.* The CC reviews CCEP-1 annually and revisions to CCEP-1 are reviewed and approved by the CC.

The CCEP-1 document:

1. Provides a comprehensive CCEP Process Flow Diagram showing the process of evaluating and approving Criteria Certification submittals, and additional processes and responsibilities in the event that noncompliances, disputes, and sanctions arise;
2. Describes the roles and responsibilities of Reporting Members, the CC, the NPCC Reliability Coordinating Committee, and the Enforcement Panel in the compliance review and enforcement process
3. Describes non-monetary Sanctions, the Lateness Policy, and the Arbitration/Dispute Resolution process
4. Addresses the development of Mitigation Plans for any violations under the enforcement process

The CCEP Working Group (under the CC) develops a draft of the annual CCEP Implementation Plan and updates the blank certification templates for the upcoming Plan year. The Implementation Plan identifies the subset of Criteria that must be certified to and includes the certification form due dates. The draft CCEP Implementation Plan for the coming year and the draft certification templates are then submitted to the CC for review and approval.

The CC members review the completed certification forms that are returned by Full Members. NPCC Staff develops an assessment report and scorecard that summarizes the certifications that were received for the CC to review and approve. The assessment report and any recommendations on noncompliances are then presented to the NPCC Reliability Coordinating Committee (RCC) for approval.

Compliance to the NPCC Criteria is a responsibility of the NPCC Members and is codified in the *AMENDED AND RESTATED BYLAWS OF NORTHEAST POWER COORDINATING COUNCIL, INC.* Implementation of the CCEP is also consist with the current Memorandum of Understating that NPCC has with its Canadian Members.

Explanation of Significant Variances – 2020 Budget versus 2019 Budget

- None.

2019 Budget and Projection and 2020 Budget Comparisons

Statement of Activities and Capital Expenditures
2019 Budget & Projection, and 2020 Budget

CRITERIA SERVICES DIVISION

		2019 Budget	2019 Projection	Variance 2019 Projection v 2019 Budget Over(Under)	2020 Budget	Variance 2020 Budget v 2019 Budget Over(Under)
Funding						
ERO Funding						
	ERO Assessments	$ -	$ -	$ -	$ -	$ -
	Penalty Sanctions	-	-	-	-	-
Total ERO Funding		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
	Membership Dues	1,058,866	1,058,866	-	1,069,402	10,536
	Testing Fees	-	-	-	-	-
	Services & Software	-	-	-	-	-
	Workshops & Misc Revenue	-	-	-	-	-
	Interest & Investment Income	-	-	-	-	-
Total Funding (A)		**$ 1,058,866**	**$ 1,058,866**	**$ -**	**$ 1,069,402**	**$ 10,536**
Expenses						
Personnel Expenses						
	Salaries	$ 371,938	$ 371,938	$ -	$ 367,979	$ (3,959)
	Payroll Taxes	23,696	23,696	-	24,864	1,168
	Benefits	102,779	102,779	-	123,261	20,482
	Retirement Costs	43,182	43,182	-	41,954	(1,228)
Total Personnel Expenses		**$ 541,596**	**$ 541,596**	**$ -**	**$ 558,057**	**$ 16,462**
Meeting Expenses						
	Meetings	$ 5,000	$ 5,000	$ -	$ 14,000	$ 9,000
	Travel	56,800	56,800	-	56,800	-
Total Meeting Expenses		**$ 61,800**	**$ 61,800**	**$ -**	**$ 70,800**	**$ 9,000**
Operating Expenses, excluding Depreciation						
	Consultants & Contracts	$ 55,360	$ 55,360	$ -	$ 76,360	$ 21,000
	Office Rent	-	-	-	-	-
	Office Costs	-	-	-	-	-
	Professional Services	-	-	-	-	-
	Computer & Equipment Leases	-	-	-	-	-
	Miscellaneous	4,000	4,000	-	4,000	-
Total Operating Expenses		**$ 59,360**	**$ 59,360**	**$ -**	**$ 80,360**	**$ 21,000**
	Total Direct Expenses	**$ 662,756**	**$ 662,756**	**$ -**	**$ 709,217**	**$ 46,462**
Indirect Expenses		**$ 415,818**	**$ 415,818**	**$ -**	**$ 409,450**	**$ (6,368)**
Other Non-Operating Expenses		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)		**$ 1,078,574**	**$ 1,078,574**	**$ -**	**$ 1,118,668**	**$ 40,094**
Change in Assets		**$ (19,707)**	**$ (19,707)**	**$ -**	**$ (49,265)**	**$ (29,558)**
Fixed Asset Additions (C)		**$ 30,000**	**$ 30,000**	**$ -**	**$ 30,000**	**$ -**
TOTAL BUDGET (=B+C)		**$ 1,108,574**	**$ 1,108,574**	**$ -**	**$ 1,148,668**	**$ 40,094**
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)		**$ (49,707)**	**$ (49,707)**	**$ -**	**$ (79,265)**	**$ (29,558)**

Personnel Analysis

Total FTE's by Program Area	Budget 2019	Projection 2019	Direct FTEs 2020 Budget	Shared FTEs[1] 2020 Budget	Total FTEs 2020 Budget	Change from 2019 Budget
CRITERIA SERVICES DIVISION						
Operational Programs						
Reliability Standards	1.07	1.07	1.00	0.08	1.08	0.01
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	0.08	1.08	0.01
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**	**0.16**	**2.16**	**0.02**
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**	**0.16**	**2.16**	**0.02**

[1]A shared FTE is defined as an employee who performs both Regional Entity and Criteria Services division functions.

Reserve Analysis 2019 - 2020

Working Capital and Operating Reserve Analysis 2019-2020
CRITERIA SERVICES DIVISION

	Total Reserve	Operating Reserve	Working Capital	Business Continuity
Beginning Total Reserve, December 31, 2018	571,369	422,614	88,755	60,000
2019 Non-Statutory Funding (from members)	1,058,866	1,058,866		
Plus: 2019 Other funding sources	0	0		
Less: 2019 Projected expenses & fixed asset additions	(1,108,574)	(1,108,574)		
Projected Total Reserve, December 31, 2019	**521,661**	**372,906**	**88,755**	**60,000**
Desired Total Reserve, December 31, 2020	**442,396**	320,137 [1]	95,718 [2]	26,540 [3]
Less: Projected Total Reserve, December 31, 2019	(521,661)	(372,906)	(88,755)	(60,000)
Increase(decrease) in assessments to achieve desired Total Reserve	(79,265)	(52,769)	6,963	(33,460)

2020 Funding requirement for expenses and fixed asset additions	1,148,668
Less: Other Funding Sources	(4,200)
Less: Release of Business Continuity Reserve Funds [3]	(33,460)
Adjustment to Working Capital to achieve desired Total Reserve balance [2]	6,963
Adjustment to Operating Reserve to achieve desired Total Reserve balance [1]	(52,769)
2020 Funding and reserve requirement	1,065,202

[1] Total NPCC Operating Reserve must be within a range from 8.33% to 25.00% of Budget. $320,137 represents 27.87% of the 2019 CS budget of $1,148,668.

[2] Total NPCC Working Capital must equal 8.33% of Budget. $95,718 represents 8.33% of the 2019 CS budget of $1,148,668.

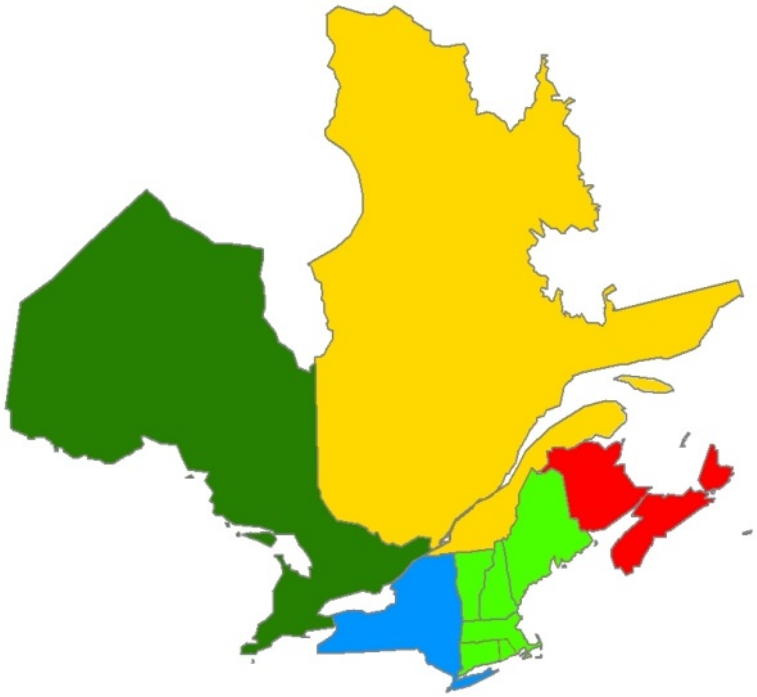
[3] Business Continuity Reserve (BCR) established in 2017 as approved by the NPCC Board of Directors to fund Succession Planning related expenses.

Explanation of Changes in Reserve Policy from Prior Year

There was no change to the existing Working Capital and Operating Reserve Policy. A separate Business Continuity Reserve (BCR) in the amount of $1,000,000 (allocated between the Regional Entity and Criteria Services divisions) was established in 2017 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 drawn upon as subsequently brought before the Board of Directors for approval of release of funds in association with President & CEO succession related activities associated with the planned or a sudden retirement, as well as other sudden changing workforce staffing requirements which could be brought about by coincident multiple staff retirements.

Section D – Additional Consolidated Financial Statements

2020 Business Plan and Budget



Section D — Additional Financial Statements

Statement of Financial Position

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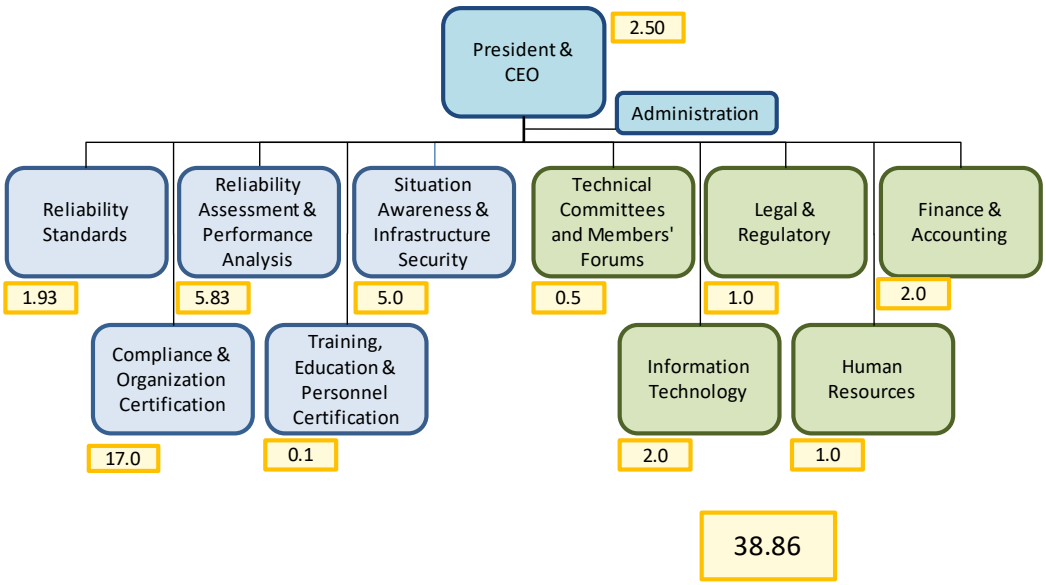
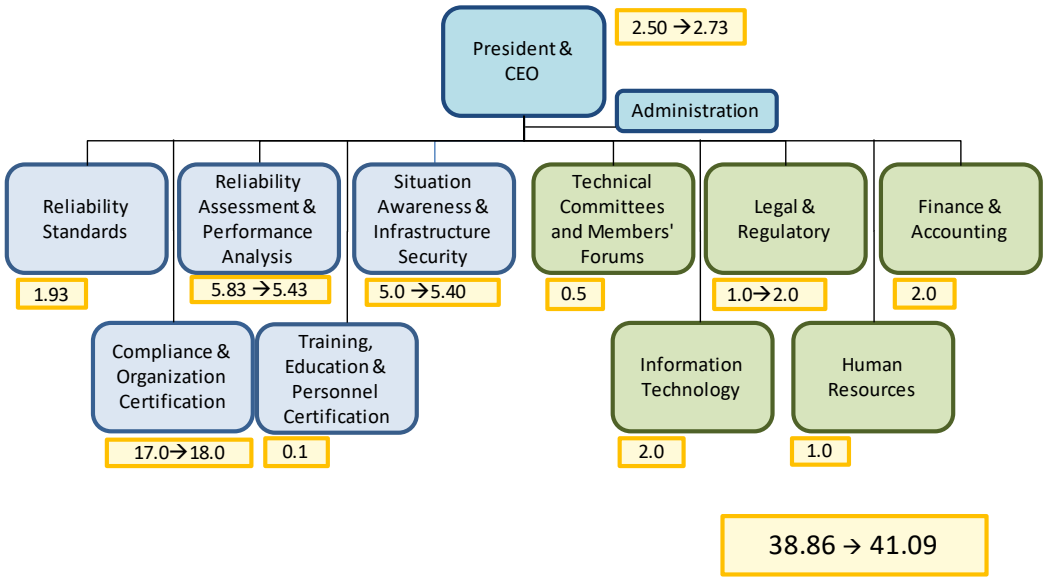
Appendix A Staff Allocations

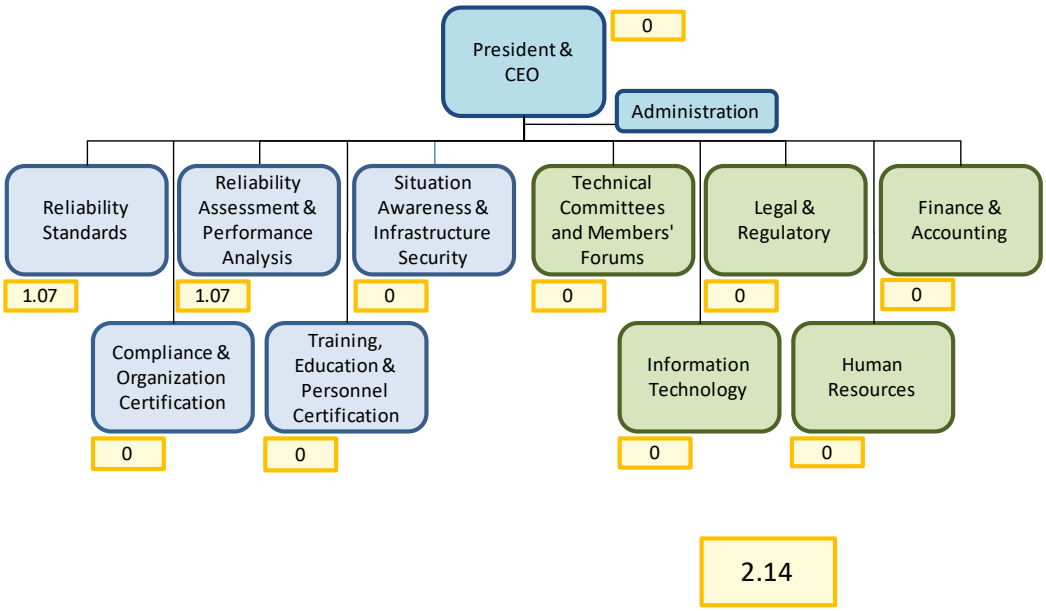
2019 Budget Staff Allocations - RE Division



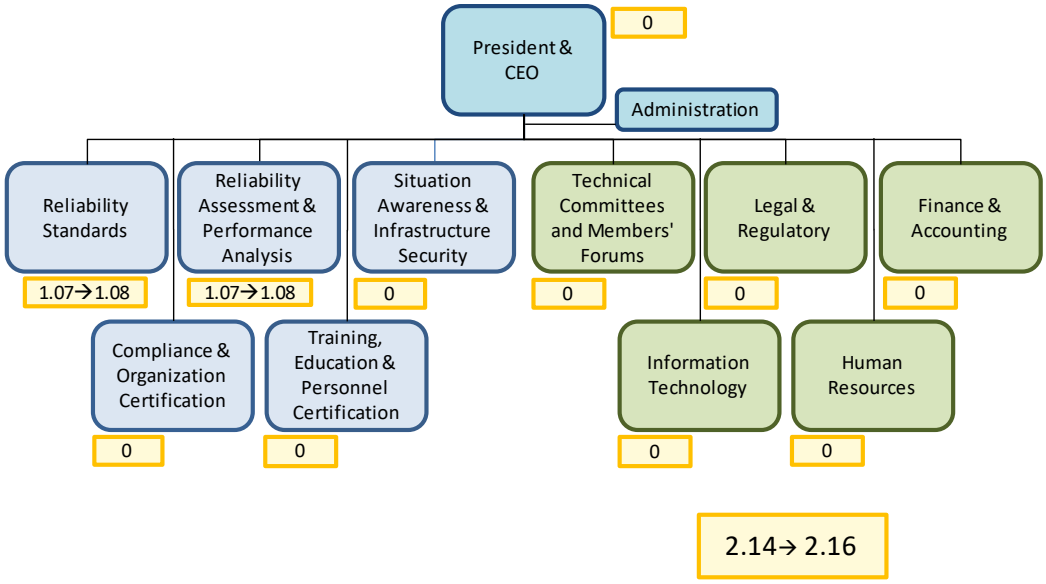
2020 Budget Staff Allocations - RE Division



2019 Budget Staff Allocations - CS Division



2020 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

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NPCC, Inc.
NORTHEAST POWER COORDINATING COUNCIL, INC.
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2020 Business Plan and Budget Preparation Schedule

2019 DATES	NERC	NPCC
January – March	Seek input from staff on business plan and budget requirements – Final assumptions to be received from NERC by early January	
February 6-7	NERC BOT and FAC Meetings – quarterly (Q1) meeting includes review of 2018 unaudited results for NERC, the Regional Entities and consolidated ERO Enterprise	
February 19	EROFG Conference Call	
February 21		NPCC FAC to review preliminary 2020 Business Plan & Budget Scenarios and endorse scenario to bring to full BOD
March 1		Make initial request for previous year NEL data
March 8		Send 2020 budget templates to AVPs to update and set meetings to discuss
March 20		NPCC BOD Meeting – present FAC endorsed 2020 BP&B Scenario
March 20	EROFG Conference Call	
March 22		Due date for AVPs to provide 2020 budget projections and draft of budget verbiage for each program area
March 26		NPCC FAC to review 2018 audited FS and BOD comments on 2020 BPB scenario
April 6	RE's resources pie chart estimated data to NERC	
April 16		Distribute Draft 1 2020 Business Plan & Budget to NPCC FAC for April 23 meeting
April 20		**Q1 RE variance report due to NERC**
April 23		NPCC FAC Teleconference – Draft 1 2020 Business Plan & Budget
April 24		Include Draft 1 2020 BP&B in 2nd mail out for May 1 BOD meeting
April 25	EROFG Conference Call	
April 26		**Draft 1 of RE Business Plans and Budgets due to NERC – NPCC will submit on May 1**

2019 DATES	NERC	NPCC
May 1		**2018 Budget to Actual True-Up files due to NERC**
May 1		**NPCC BOD Meeting – present Draft 1 2020 Business Plan & Budget**
May 1		**Post Draft 1 2020 BP&B to NPCC website for comment through May 31**
May 8-9	NERC FAC Meeting- review of year-end financial statements	
May 8-9	MRC Meeting-Presentation of Draft NERC BP&B and ERO consolidated BP&B presented by NERC management	
May 10	RE Presentations to FERC and NERC FAC slides due to NERC	
May 16 (if needed)		Distribute Draft 1 BP&B to NPCC FAC w/ comments received to date for May 24 meeting
May 17	Draft 1 of NERC Business Plan and Budget posted on NERC website	Draft 1 of RE Business Plans and Budgets posted on NERC website
May TBD	**NERC and REs present draft Business Plan and Budgets to FERC staff in DC**	
May 30	NERC and Regional Entity 2018 budget to actual true-up filing due to FERC	
May 30	**NERC Finance and Audit Committee and management conference call and webinar to review 1st draft of NERC, Regional Entity and ERO Enterprise 2020 NERC BP&Bs**	
May 23 (if needed)		NPCC FAC Teleconference – review Draft BP&B comments received (if needed)
May 29		**Present Draft 1 NPCC BP&B at RCC meeting**
May 30	**NERC Finance and Audit Committee and management conference call and webinar to review 1st draft of NERC, Regional Entity and ERO Enterprise 2020 NERC BP&Bs**	
June 5		**NPCC BOD Meeting – present Update on Draft BP&B** (present comments and changes - if any material changes)
June 17		NPCC FAC Teleconference – endorse Draft for Approval 2020 BP&B
June 17	EROFG Conference Call	
June 19		**Distribute Draft for Approval 2020 BP&B to NPCC BOD in 2nd mailout for June 26th Meeting**
June 26		**NPCC BOD Meeting - Approval of 2020 BP&B**

2019 DATES	NERC	NPCC
July 2	NERC management meets with MRC BP&B input group and Trades to discuss comments received on draft NERC draft BP&B and obtain informal input (conference call established to allow other MRC members and stakeholders to participate)	
July 9		**Final Regional Entity 2020 budget submittal due to NERC (approved by Regional Entity Boards) together with final list of LSEs and NEL data**
July 12	NERC posts final NERC draft 2020 BP&B, final Regional Entity 2020 BP&Bs and consolidated ERO Enterprise 2020 BP&B	
July 16	EROFG Conference Call	
July 18	FAC webinar to review final of NERC BP&B and final RE budget submittals	**RE's present final 2020 BP&Bs to NERC FAC**
July 20		Q2 RE variance report due to NERC
July 27	Comments due on final draft of 2020 NERC BP&B	
July TBD	EROFG presents Final 2020 BP&Bs to FERC via teleconference	
August 7	Final NERC and RE business plans, budgets and assessments posted for NERC FAC, Board of Trustees and Member Representatives Committee	
August 9	NERC FAC Meeting to review and recommend approval of NERC and RE final BP&Bs	
August 14-15	NERC and RE business plans, budgets and assessments presented to NERC Board of Trustees for approval	
August 23	Submit package to FERC and Canadian provincial authorities for approval. Package to include: (1) the NERC and RE business plans and budgets approved by the Board of Trustees, (2) NERC's annual funding requirement (including regional entity costs for delegated functions) and (3) the mechanism for assessing charges to recover that annual funding requirement.	

BPS Reliability Implications of High Levels of Inverter-Based Resources

EPRI's Transmission Operations & Planning R&D Overview

Evangelos Farantatos, Ph.D
Sr. Technical Leader
Transmission Operations & Planning, EPRI

Presentation at NPCC Regional Standards Committee
May 16 2019

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Outline

- Transmission Hosting Capacity
- IBR in Weak Grids - Modeling & Analysis Tools
- Grid Operation with 100% IBR

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Transmission Hosting Capacity Tool

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Hosting Capacity Tool for a Transmission Network

Inspiration

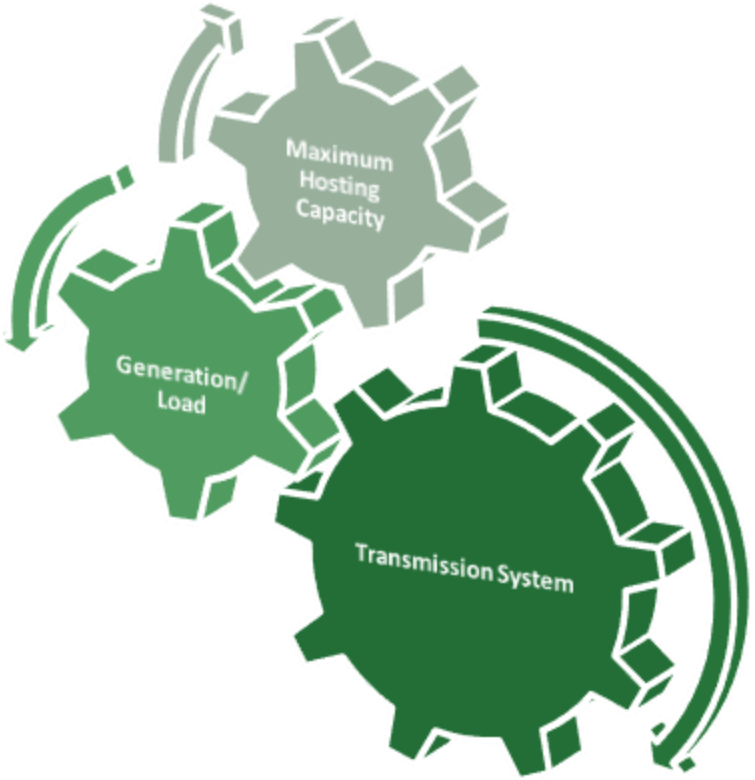
- **Distributed PV Hosting Capacity Tool for a distribution system**
- A screening tool which provides maximum potential PV deployments across a distribution system
  - "As-is" without any system upgrades

Goal

- **Develop a similar automated tool/engine for transmission system**
  - Provides maximum renewable generation/DER a transmission region can host without any network upgrades
  - High-level screening tool

Value

- Better understanding of where and how much new generation resources would impact the system
- Identify optimal versus non-optimal locations of future renewable generation/DER deployments such that grid updates can be minimized



Disclaimer : The tool is not intended to replace detail feasibility and system impact studies which are imperative to make to any investment decisions

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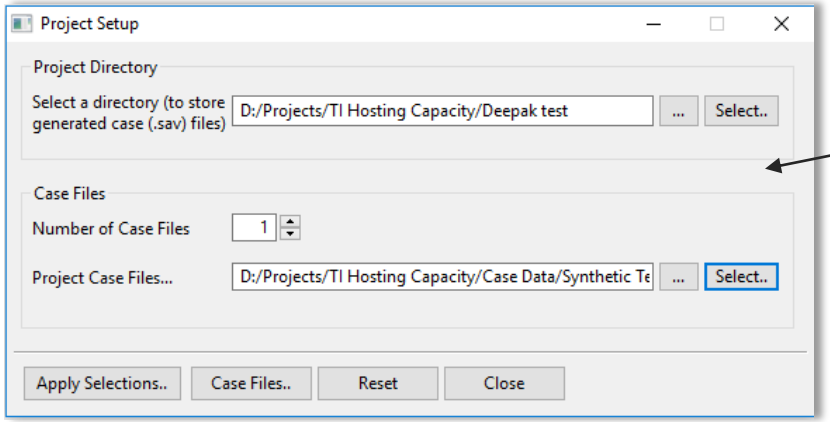
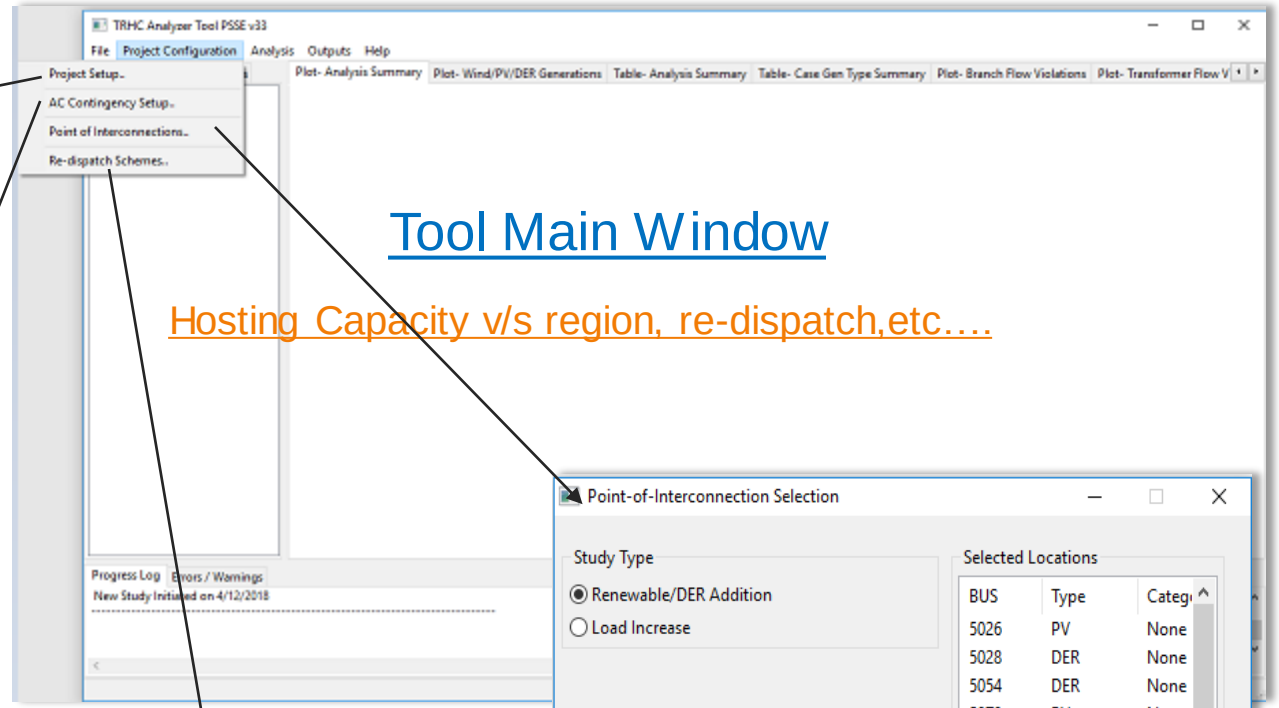
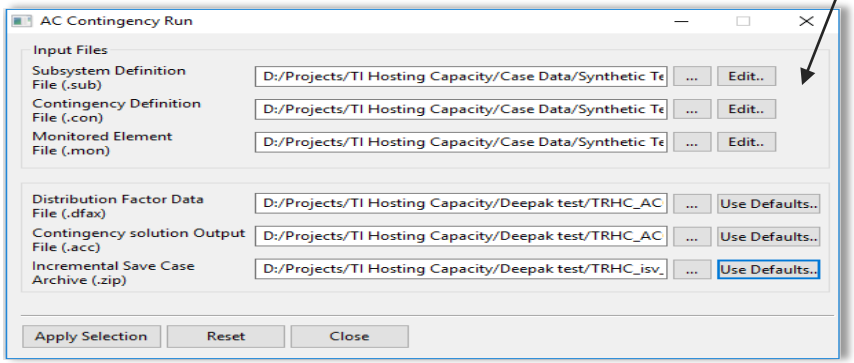
Transmission Hosting Capacity Tool : GUI

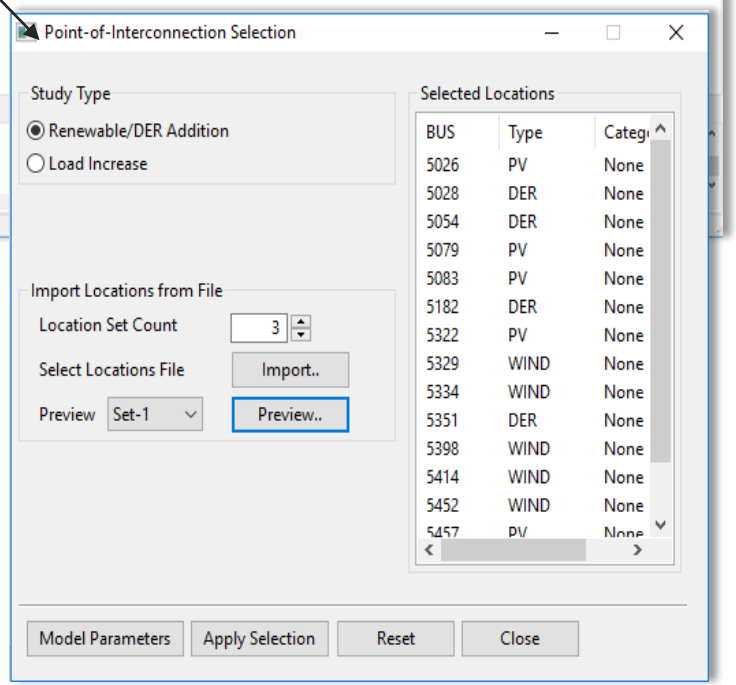


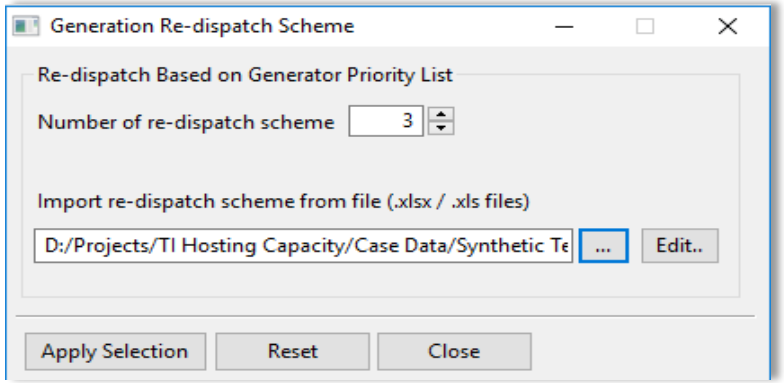


Tool Main Window

Hosting Capacity v/s region, re-dispatch,etc….







- Tool presently compatible with Siemens PTI PSS®E v33 and Python v2.7
- PID#: 3002013642

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RES Modeling & Planning Tools for Weak Grids

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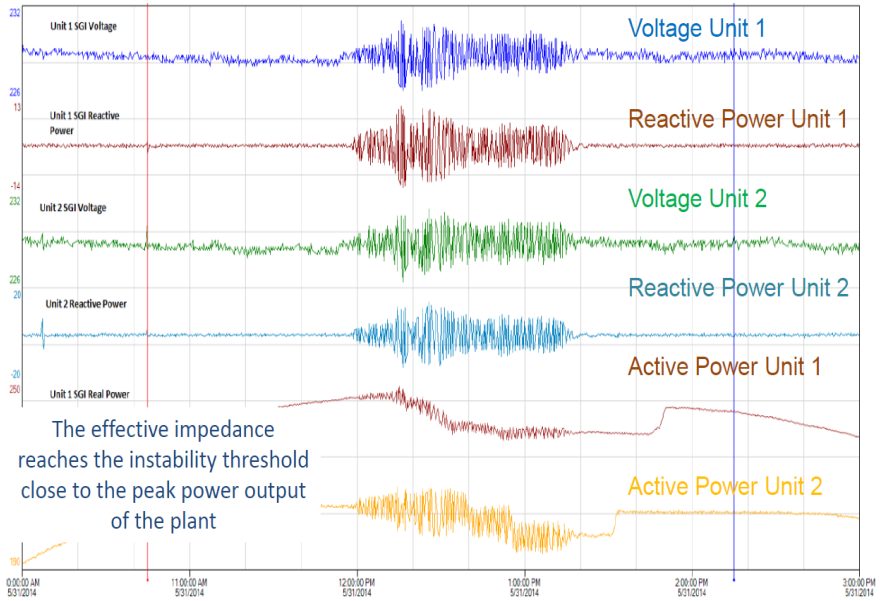
Inverters and Weak Grids

- Wind/Solar interconnections in weak systems are becoming more common
- Contingencies or scheduled outages (e.g. lines under maintenance) may reduce system strength below typical levels expected under normal operating conditions.
- Additionally, if such a network situation coincides with ramping up of the plant, the location can become even weaker
- Converter controller instabilities might occur under weak grid conditions



Source: "Deploying Utility-Scale PV Power Plants in Weak Grids", First Solar, 2017 PES General Meeting, Chicago, IL, July 2017

- No clear industry standard on metrics & associated thresholds to identify a weak area of the system
- Low SCR doesn't necessarily imply converter control instability

Table 2.1: Comparison of SCR Methods

Metric		Simple calculation using short circuit program	Accounts for nearby inverter based equipment	Provides common metric across a larger group of VER	Accounts for weak electrical coupling between plants within larger group	Considers non-active power inverter capacity*	Able to consider individual sub-plants within larger group
SCR	Short Circuit Ratio	★★	X	X	X	X	X
CSCR	Composite SCR	★	★★	★★	X	X	X
WSCR-MW	Weighted SCR using MW	★	★★	★★	★	X	X
WSCR-MVA	Weighted SCR using MVA	★	★★	★★	★	★★	X
SCRIF	Multi-Infeed SCR	X	★★	X	★★	★★	★★

Source: "Integrating Variable Energy Resources into Weak Power Systems", NERC, June 2017

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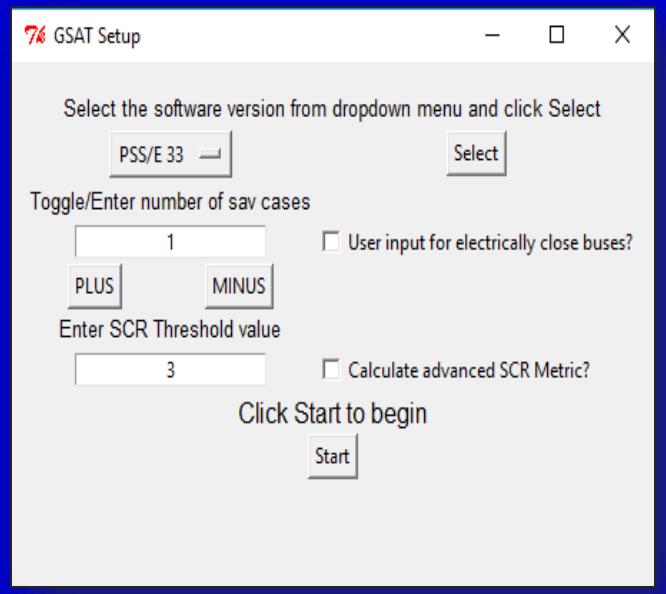
Renewables Weak Grid Modeling & Analysis

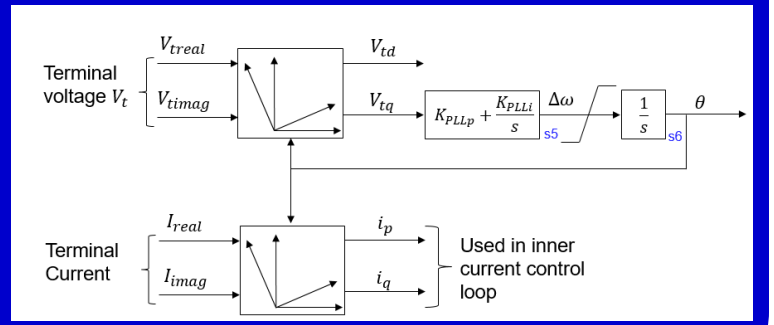
Grid Strength Assessment Tool (GSAT)



New Advanced Short Circuit Strength Metric

Bus	Critical Clearing Time (s)
1	0.4420 - 0.4906
2	0.4024 - 0.4508
3	0.4423 - 0.4910
4	0.1088 - 0.1460
5	0.1102 - 0.1476
6	0.1286 - 0.1711
7	0.1513 - 0.1957

New Proposed Converter Positive Sequence Model (REGC_C)



Ultimate Goal: Guidelines for planning and operations support engineers for RES modeling in weak grid studies & need for positive sequence vs three-phase modeling

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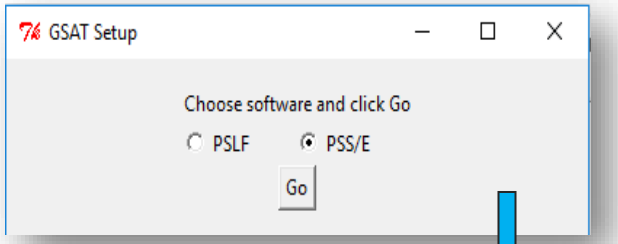
Grid Strength Assessment Tool (GSAT)

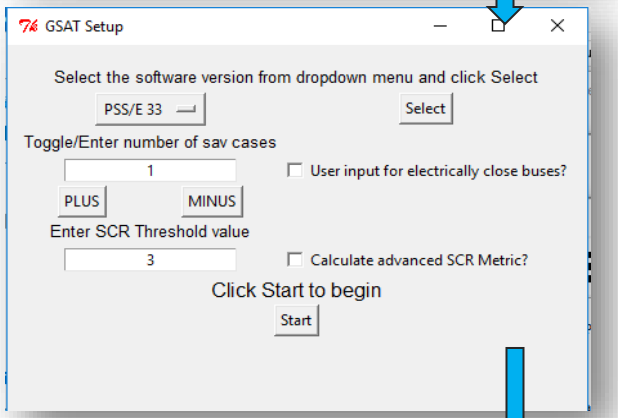
Goal: provide insights on

- **Network locations/conditions which could be susceptible to issues related to weak grid conditions**
- **The need for detailed assessment methods**

- Presently supports:
  - Siemens PTI PSS®E v33 and v34
  - GE-PSLF™ v19 and v21
  - DIgSILENT PowerFactory 2018 SP1
- Evaluates:
  - **Generic SCR**
  - **Weighted SCR** – with either automatic evaluation of electrically close buses or user provided input
  - **Composite SCR** - with either automatic evaluation of electrically close buses or user provided input
  - **Advanced SCS**– to provide preliminary insight into necessity of EMTP level simulations
- Steady state analysis (no dynamic simulations performed)
- Allows multiple power flow files as input

PID#: 3002013640





Simple SCR

Bus	Thevenin Impedance Magnitude (pu)	SCC MVA	SCR
A	0.653507	155.6983	6.227933
B	1.129373	90.31558	11.28945
C	0.649164	157.1251	6.285003
D	0.326675	306.1143	2.448914
E	0.348464	286.9736	2.452766
F	0.22936	435.9957	2.62648
G	0.226463	441.5738	2.660083
H	0.224102	459.612	2.41901
I	1.159429	86.24937	1.306809

Weighted Short Circuit Ratio Calculation

Buses	WSCR
A B C H I	1.030081
F G	1.321641

Composite Short Circuit Ratio Calculation

Buses	CSCR
A B C H I	1.752081
F G	1.907745

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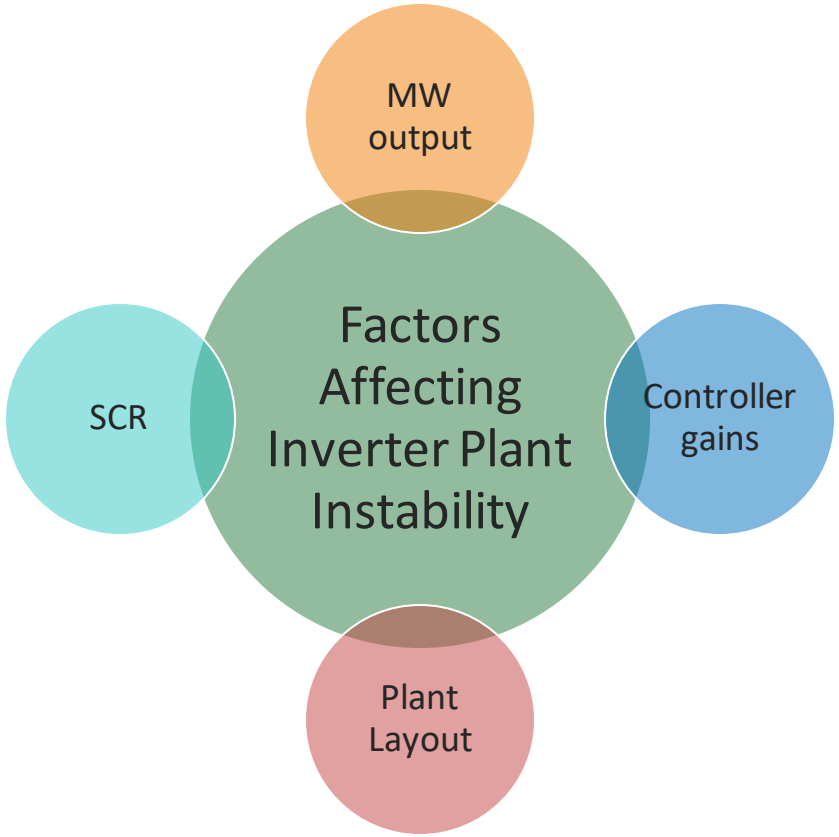
SCR Does Not Provide The Entire Picture…

- For an inverter plant, a low or high value of SCR may not provide the entire picture about control instability



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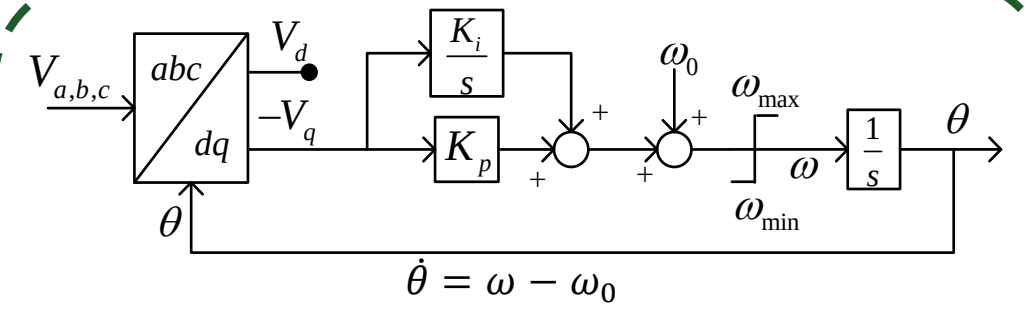
Proposed New Converter Control Stability Index



$$\dot{\theta} = \omega - \omega_0$$

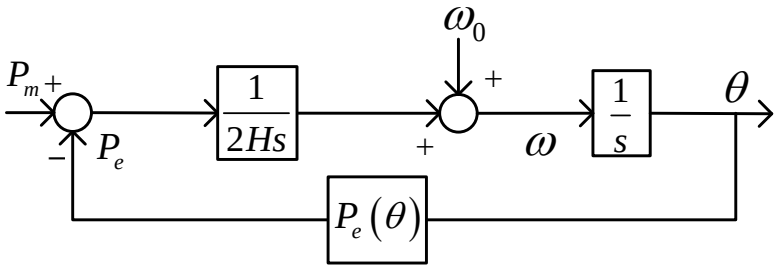
$$\frac{1}{K_i}\dot{\omega} = -V_q = \underbrace{(I_d X - I_q R)}_{R1} - \underbrace{E_{eq}\sin\theta}_{R2(\theta)}$$

PLL Dynamics

(ignoring K_p and ω limit)

Similar

Mathematically

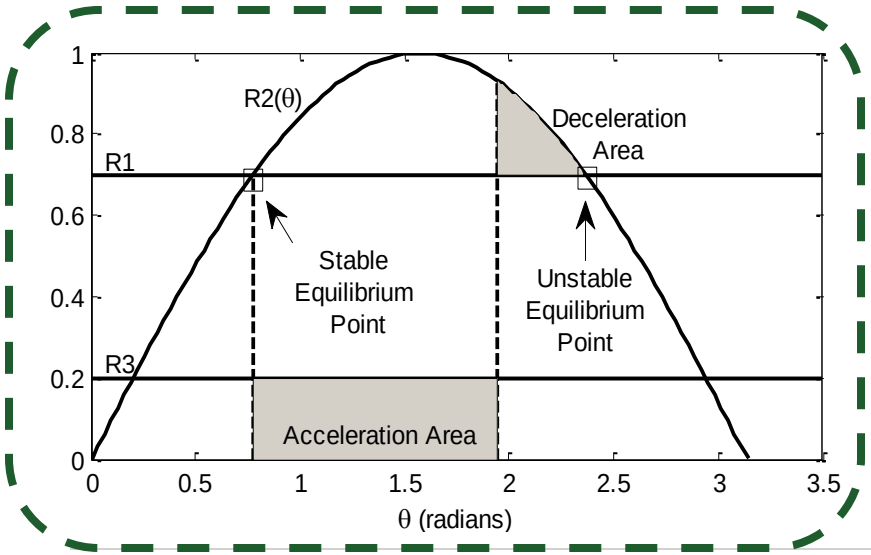


$$\dot{\theta} = \omega - \omega_0$$

$$2H\dot{\omega} = P_m - P_e(\theta)$$

Synchronous machine

swing equations



- Equal areal criterion is adapted to obtain the critical clearing time (t_{cc}) for a solid three phase fault at the IBR PCC bus
- Stability index:
  - is obtained analytically
  - accounts for the dynamic interaction between PLL and grid side converter (GSC) controls
  - is able to capture impact of system strength, IBR operating conditions, PLL and GSC control parameters

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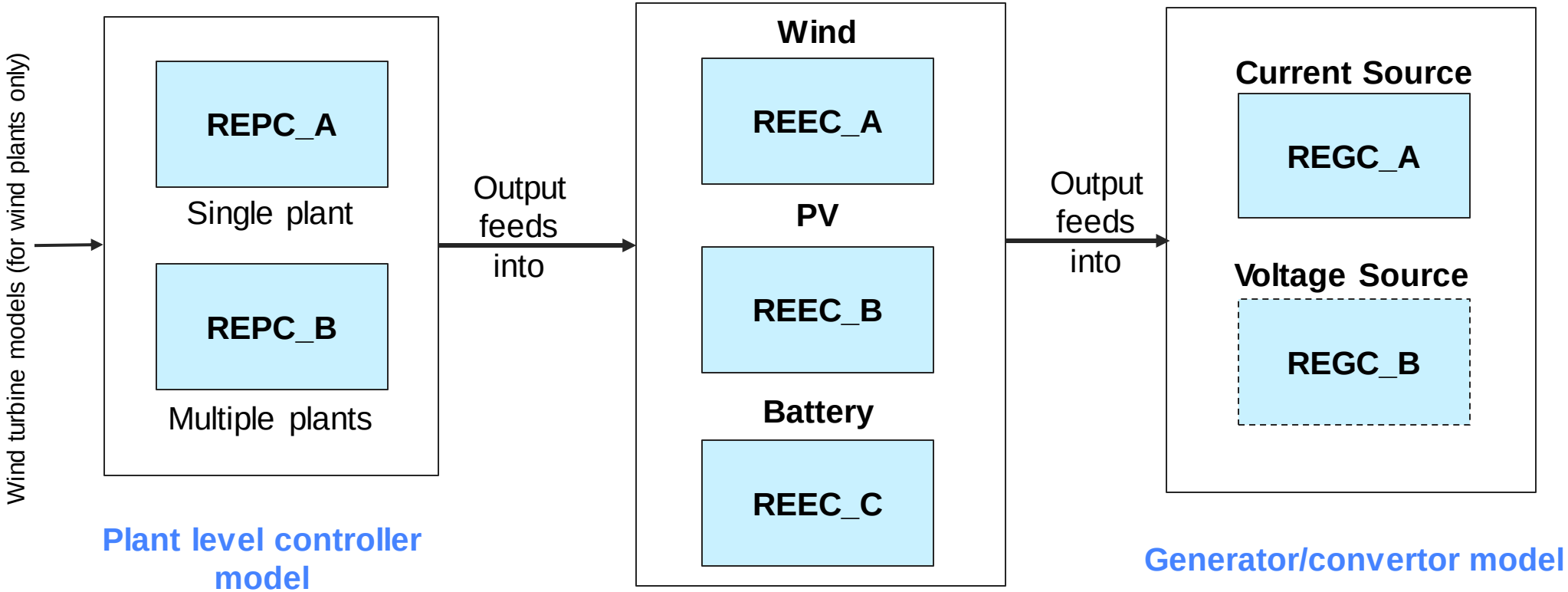
2nd Generation RES Models - Modules



Plant level controller model

Electrical controller model

Generator/convertor model

Latest renewable energy models available in commercial platforms for dynamic studies (positive sequence)

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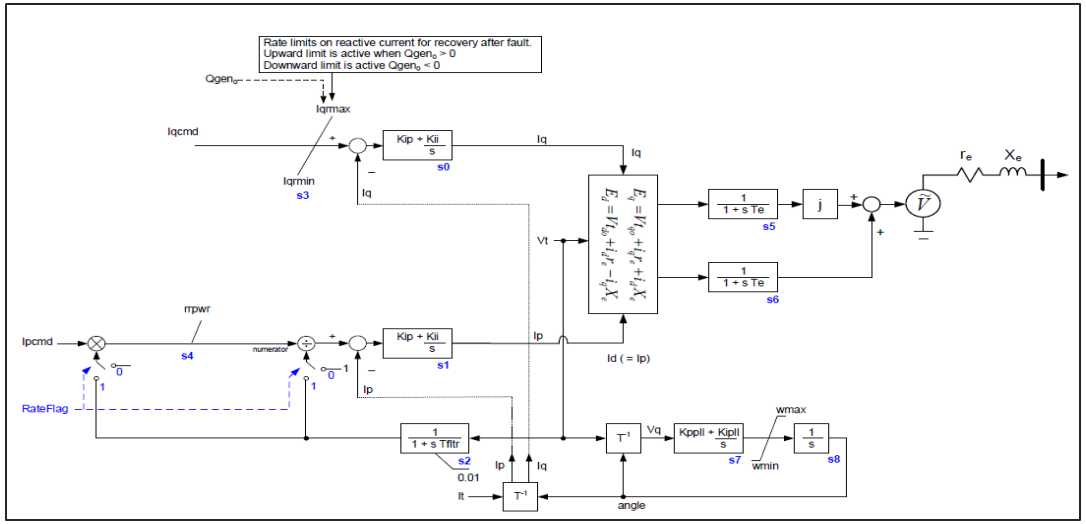
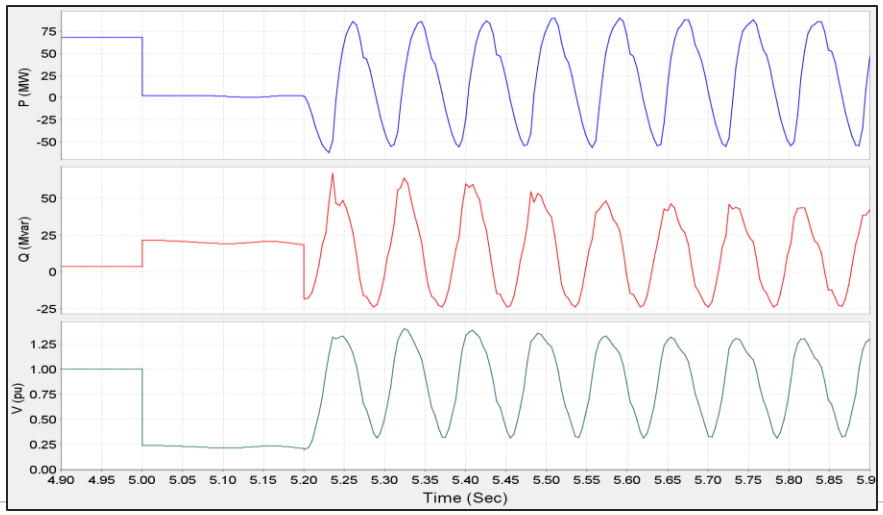
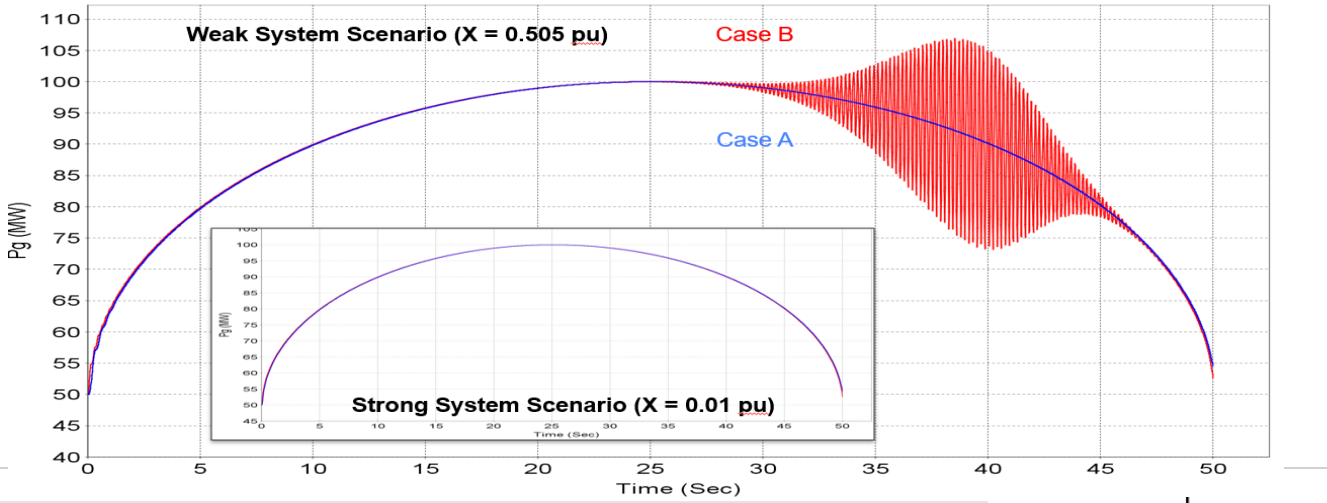
Proposed REGC_C (Positive Sequence Model)

- Representation of PLL and inner current control loop
- Model under discussion at WECC REMTF
- Small timestep required (1ms)
- **Improves numerical stability**
- **Suggested to be used for weak grid studies before conducting detailed three-phase EMT studies**
- 2019 Work:
  - Further testing of the model (user defined model in PSS/E and PSLF)
  - Engagement with WECC REMTF for model approval
  - Pursue model validation using field measurements







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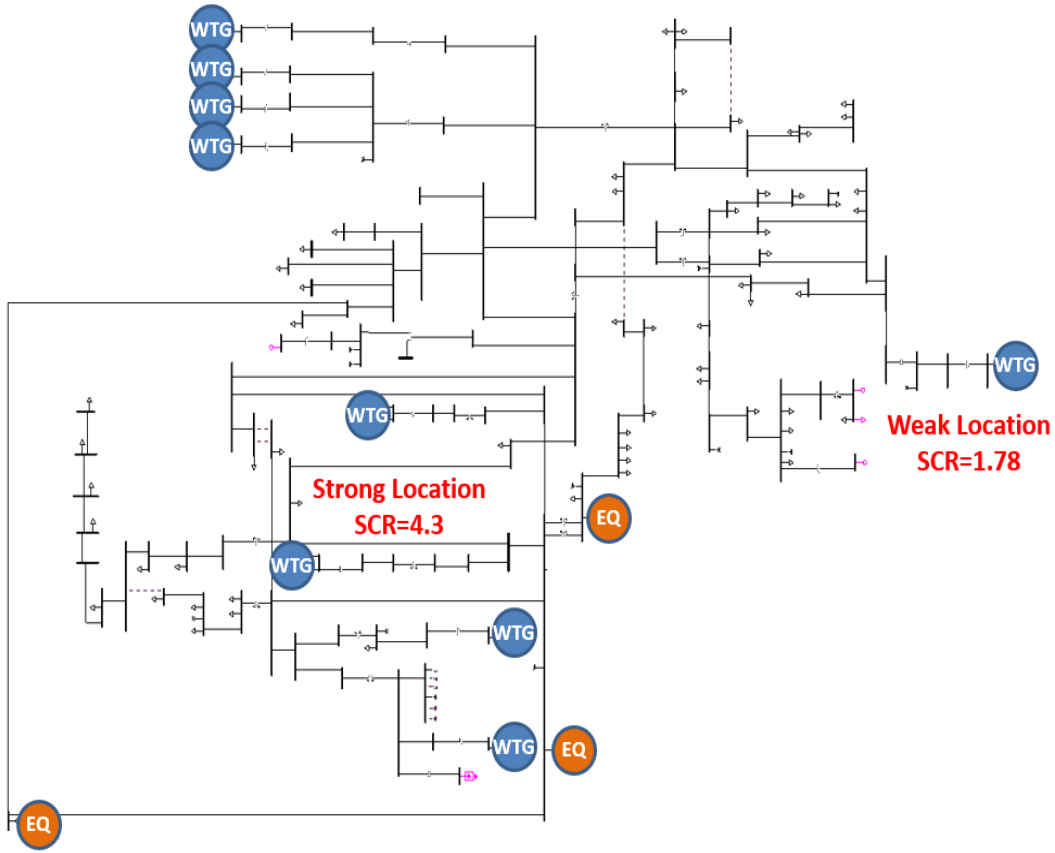
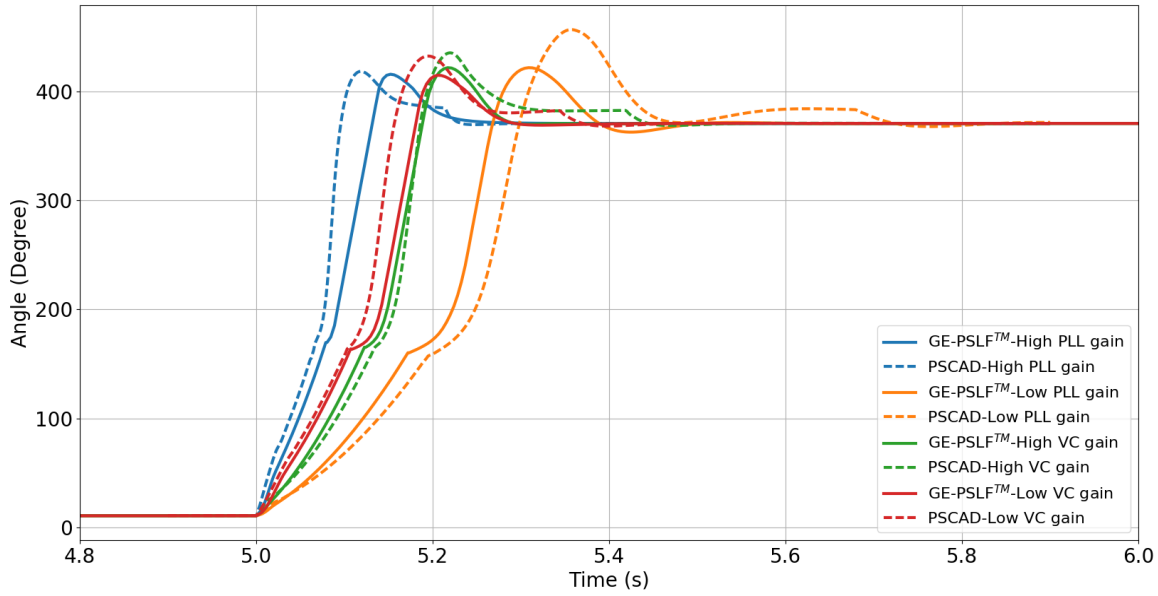
AEP Test System Results

- Benchmarking between REGC_C, EMT Model and Proposed Stability Index



WTG	PSCAD Critical Clearing Time (cycles of 60 Hz)	REGC_C Critical Clearing Time (cycles of 60Hz)	Proposed Stability Index (cycles of 60Hz)
WTG 9	3.77	4.65	3.74
WTG 5	6.65	6.95	6.44
WTG 6	6.79	6.45	6.71
Group 2	7.32	7.05	7.00
Group 1	7.47	7.05	7.06



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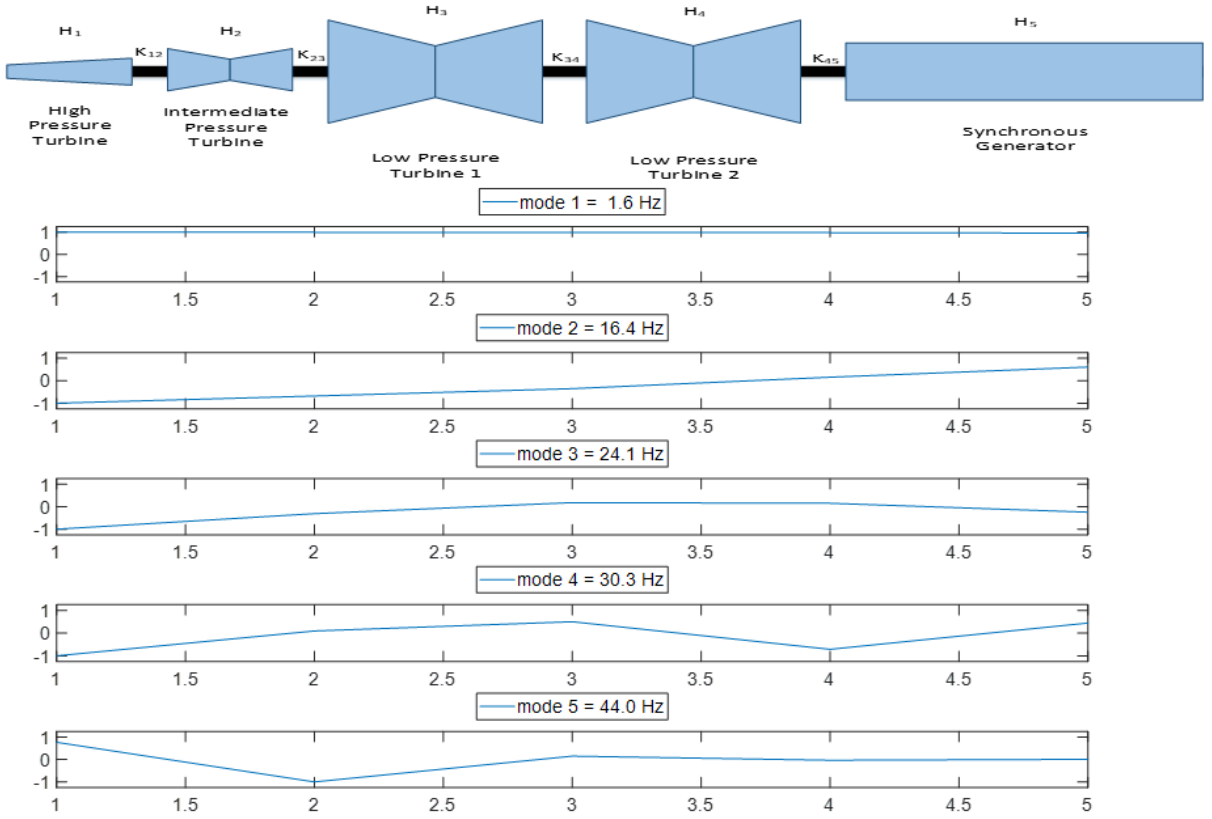
Sub Synchronous Oscillations White Paper Outline

- Review of industry trends that may increase risk of SSO
- Review of phenomena
  - SSR, SSTI, SSCI
- Review of current events and potential concerns
  - SSR in grids with multiple IBR
  - SSCI in areas with multiple IBRs tightly coupled, e.g., weak grid spots
  - SSTI in weak grid areas, between VSD and generators, etc
- Review of screening methods & effectiveness
  - Well established: frequency scans, modal analysis, UIF, etc
  - Newer improved methods
- Review of detailed methods for analysis
  - EMT simulations, models needed, small signal analysis, loss of fatigue life calculation, etc
- Review of mitigation techniques
  - Operational guidelines, fast bypass schemes, SSDCs on generators and FACTs, damping filters, blocking filters, torsional stress relays, etc
- Recommendations



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100% Inverter Based Bulk Power System

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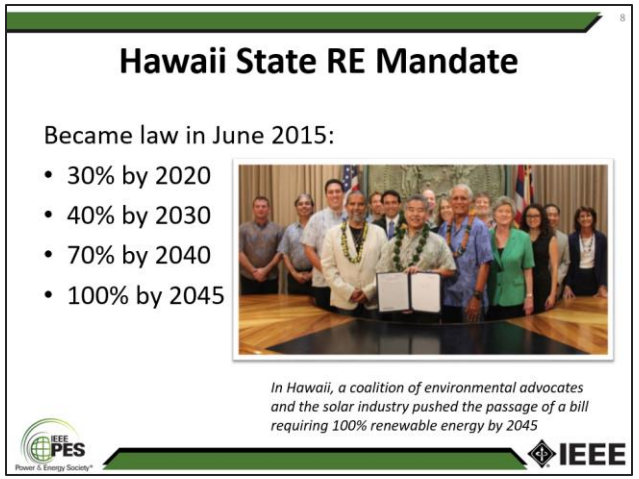
Moving Towards 100%

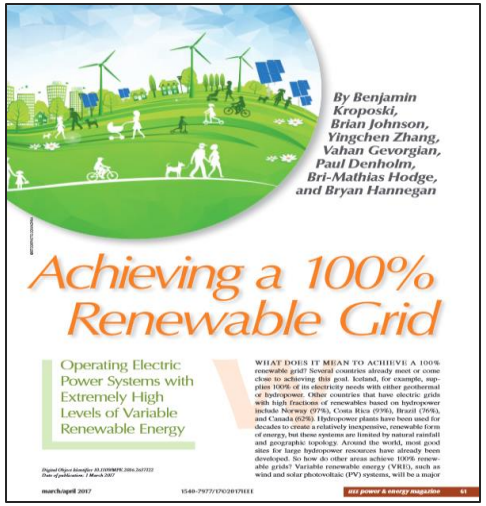
The 100 Percent Clean Energy Act of 2018: "…100 percent of total retail sales of electricity in California to come from eligible renewable energy resources and zero-carbon resources by December 31, 2045"

MIGRATE Project (Massive Inte**GRAT**ion of power **E**lectronic devices**): An EU-funded project under the framework of European Union's horizon 2020**

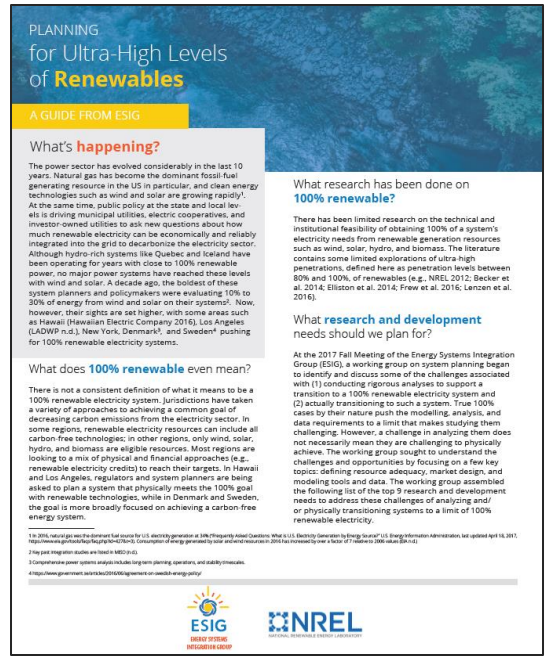
Source: https://www.h2020-migrate.eu/



Source: IEEE PESGM 2018



Source: IEEE PES Power & Energy Magazine – March/April 2017 Issue



Source: ESIG

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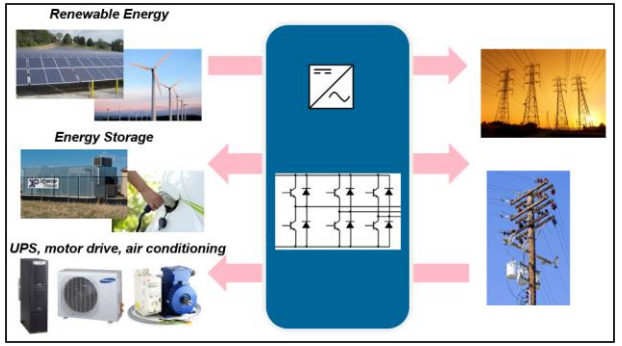
Defining 100%

❑ *100% Renewable/Clean Energy*

Source: NYPA Niagara Hydro Plant

VS

100% Inverter Based Resources Energy



- For a small scale system it's feasible:
  - Consider Iceland (75% Hydro – 25% Geothermal)
- Large scale system

❑ 100% for 24/7 vs 100% for time intervals

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EPRI Project Scope

Can we operate a system with all IBR/VER?

Multifaceted Challenge

Stability

- Frequency definition
- System stability mechanism – physical inertia vs inverter controls
- Inverter controls - Primary/secondary
- Interaction of inverter controls with synchronous machines controls
- Motor load behavior

Protection

Scheduling/ Balancing

Market Operations/ Design

- Flexibility of generation fleet
- Operating reserves
- Curtailment of renewables
- Market price implications
- Use of energy storage

Resource Planning/ Adequacy

Disclaimer: The work conducted under this project is considered foundational towards a multi-year R&D plan that is expected to be executed under various EPRI projects in the near future. This project does not intend to answer all questions, it rather raises open questions, presents ideas and conceptual designs of potential operating schemes

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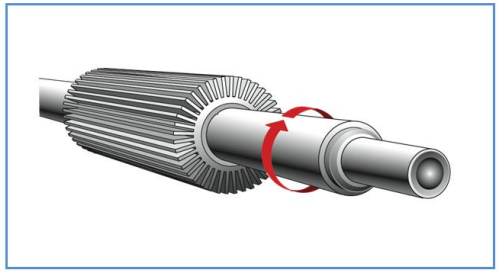
Conventional System Frequency vs. All-Inverter System Frequency

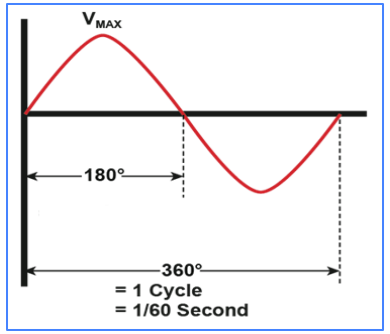
Frequency definition and its importance in an all inverter system

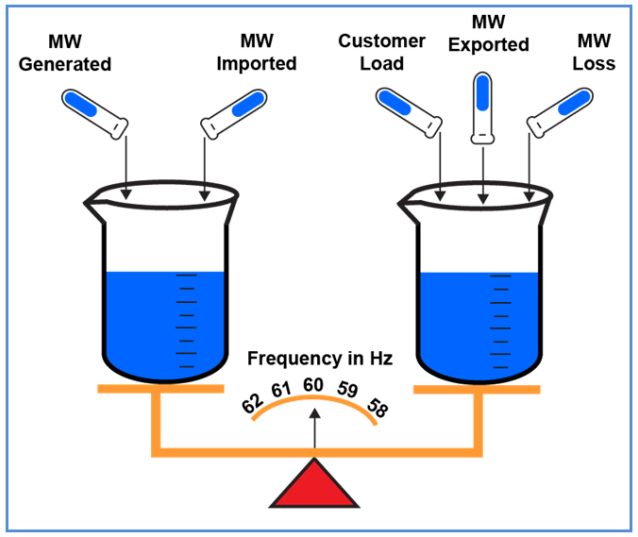
Conventional System

Mechanical Frequency



Electrical Frequency

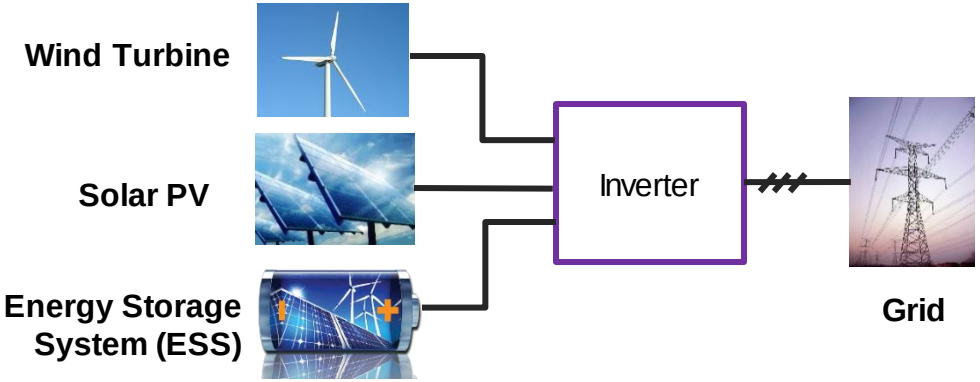




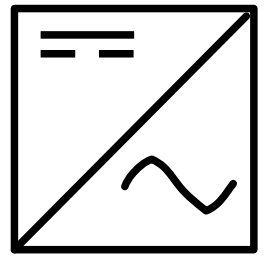
- Frequency: Supply/demand balance
- Stability: Inertia - rotor angle

vs

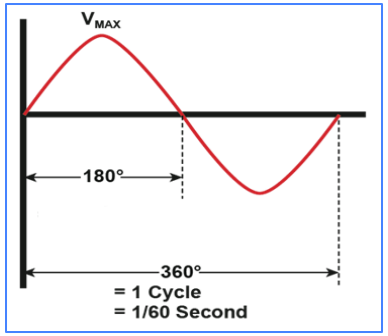
100% IBR System



No mechanical frequency



Electrical Frequency



- Electrical frequency: Rate of change of system angles
- Stability: Inverter controls

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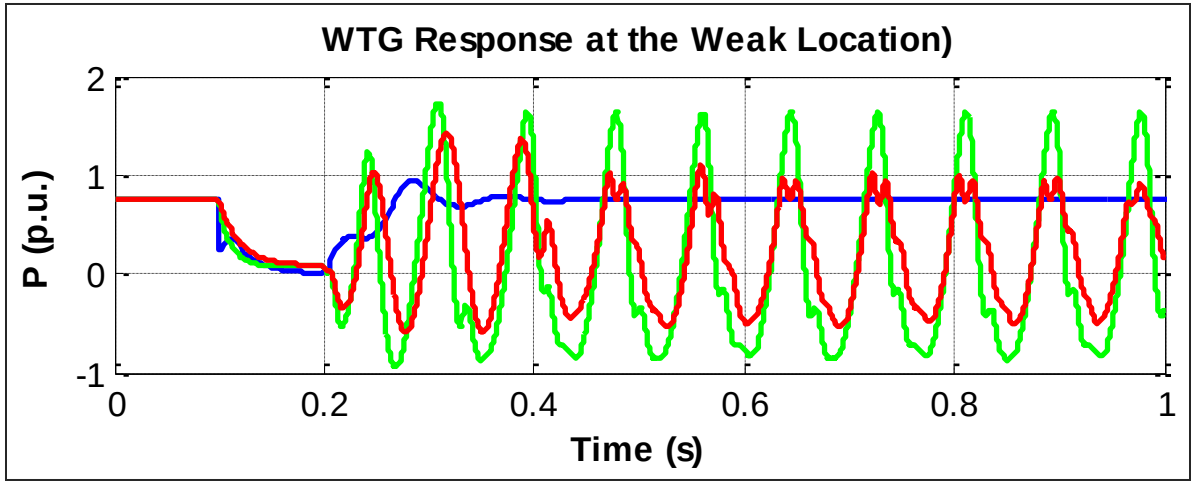
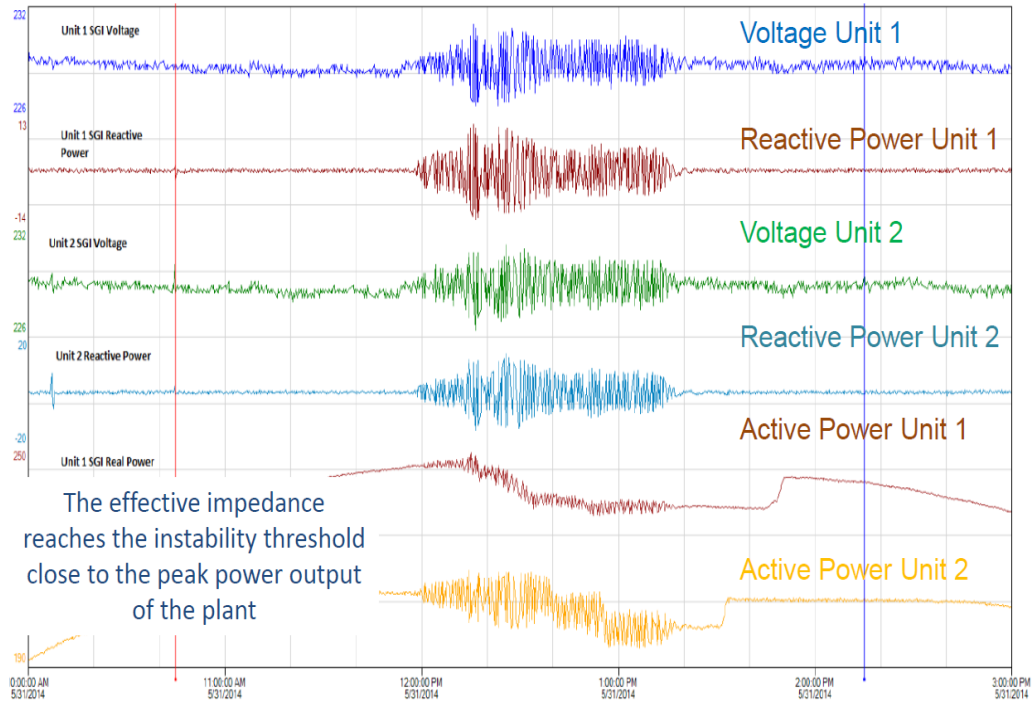
Inverter Controls Behavior in Weak Systems

Transient Stability



Small Signal Stability



Source: "Deploying Utility-Scale PV Power Plants in Weak Grids", First Solar, 2017 PES General Meeting, Chicago, IL, July 2017

Inverter Control Instabilities Under Weak Grid Scenarios

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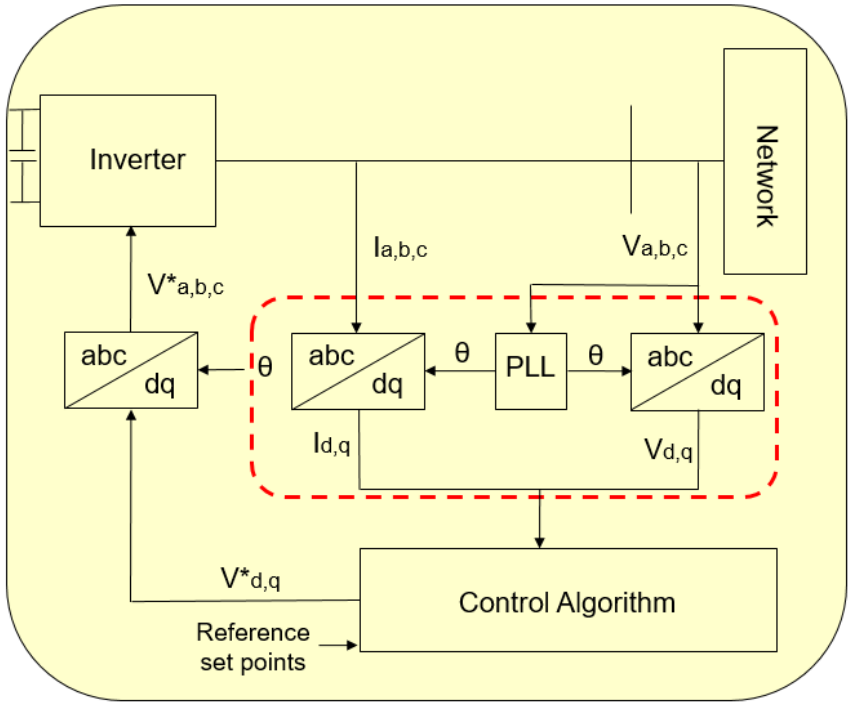
Types of Converter Controls

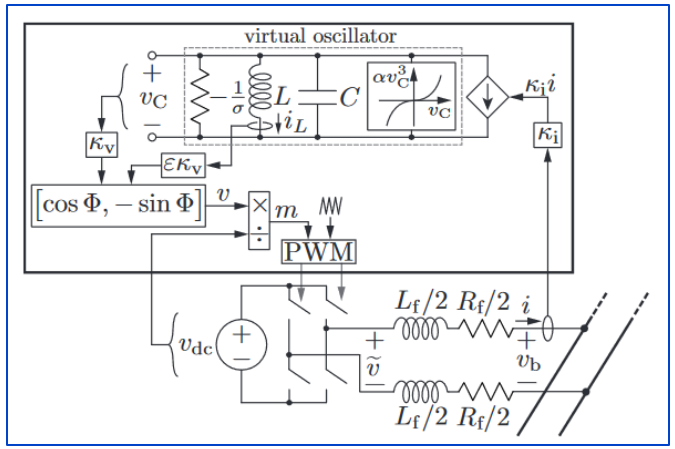
Grid following

Requires synchronization to the grid to perform control function

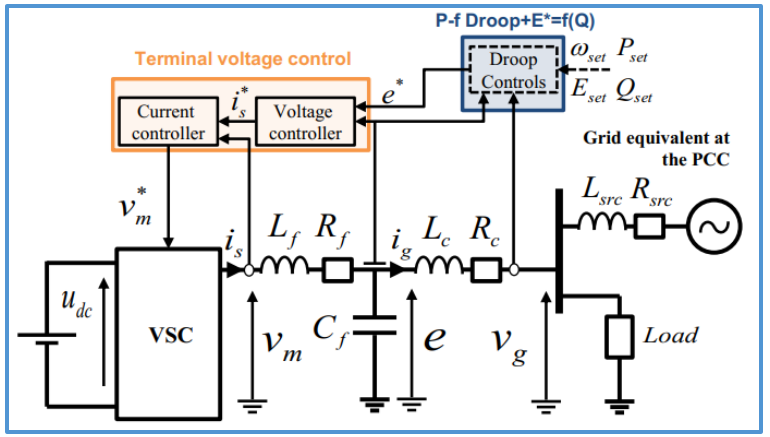


Grid forming*

Establishes voltage and frequency (black-start capability)



Source: NREL



Source: MIGRATE, RTE

** No industry accepted performance specifications yet*

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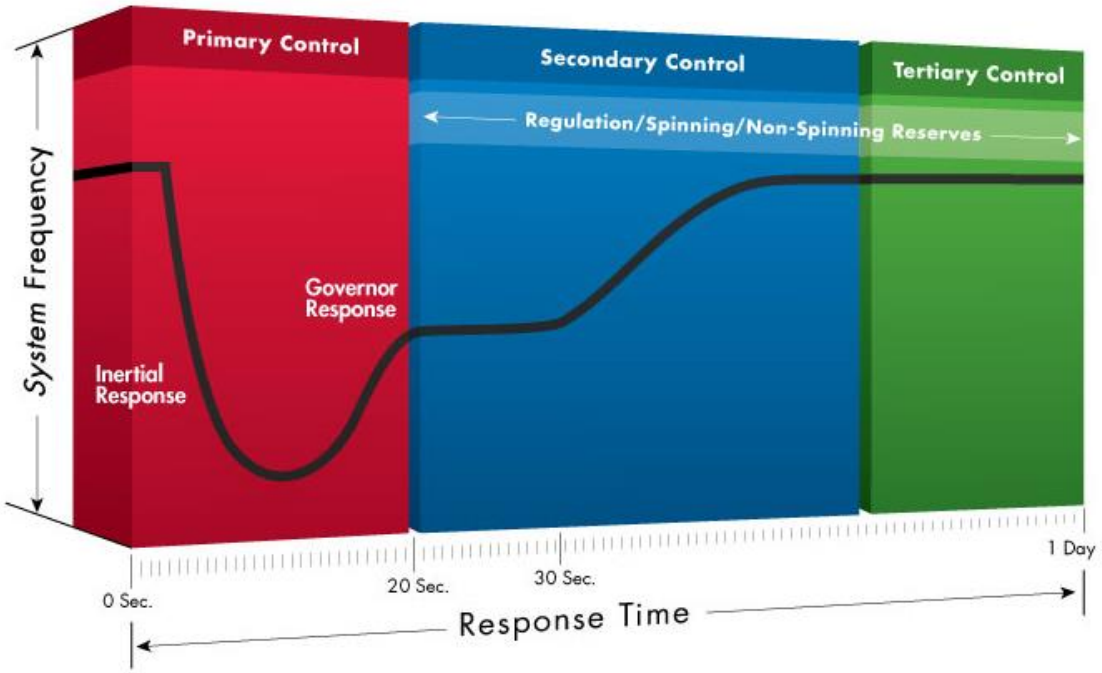
Constant Frequency System Operation

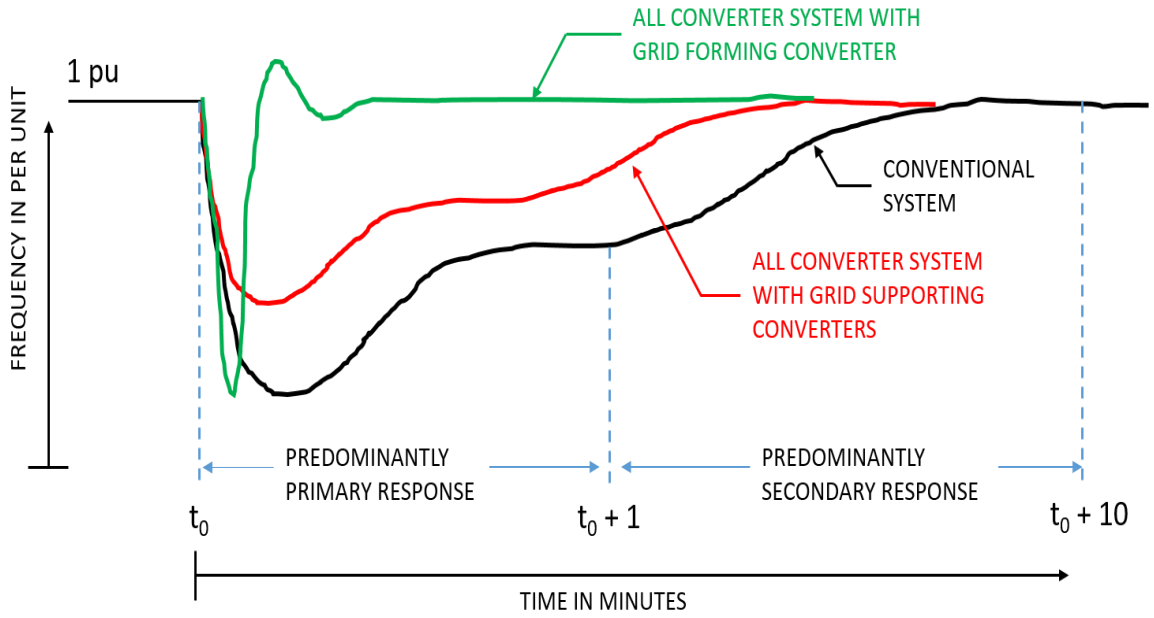
Conventional system response to disturbance:

- Inertial response
- Primary frequency response to stabilize frequency: Timeframe ~ 1 minute
- Secondary frequency response to restore nominal frequency. Only the area affected takes up the burden. Timeframe ~ 10 minutes



All converter system with grid forming inverter response to disturbance:

- Frequency restores to nominal value within seconds.



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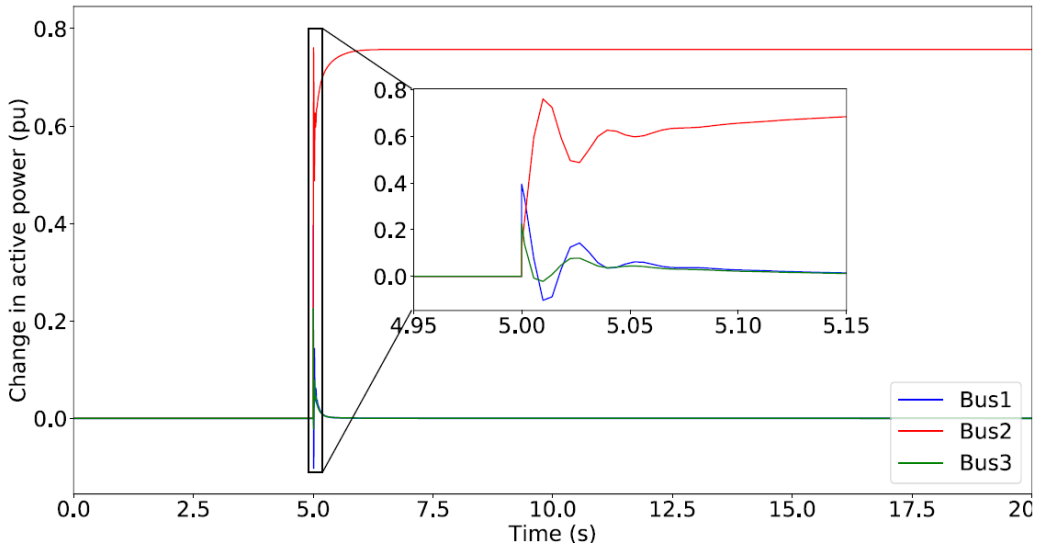
Reliability Implications of Constant Frequency Operation

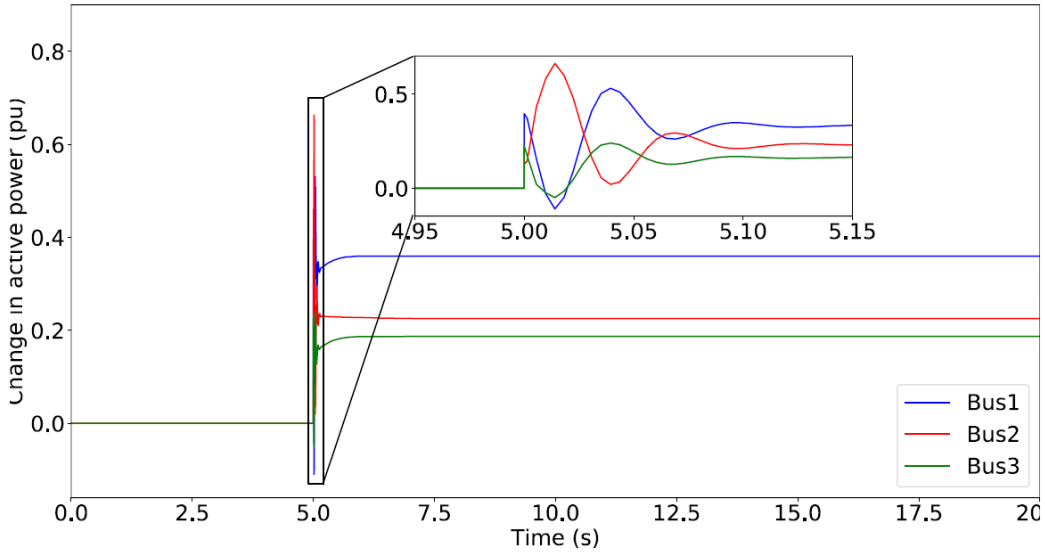
Power sharing upon a disturbance: Frequency droop is not applicable under constant frequency control

Angle Droop

Frequency droop: No power sharing



Angle droop: All IBR share load increase



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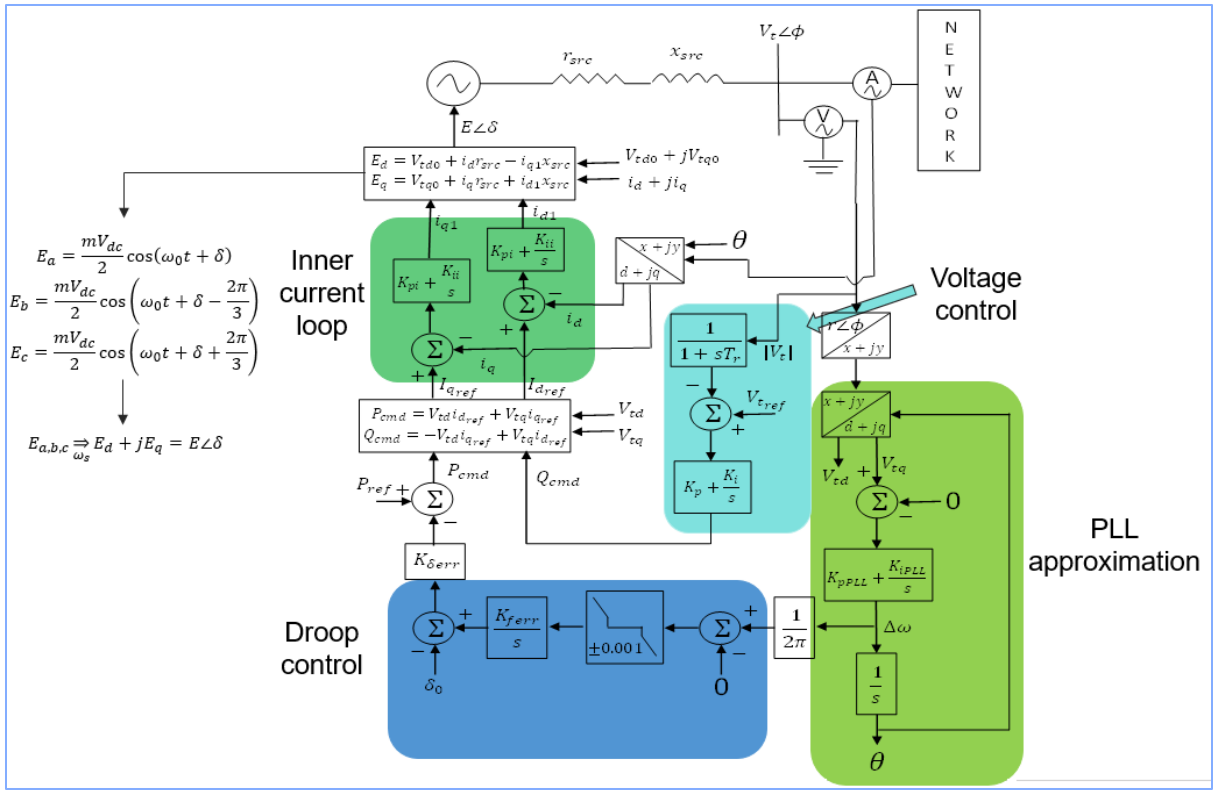
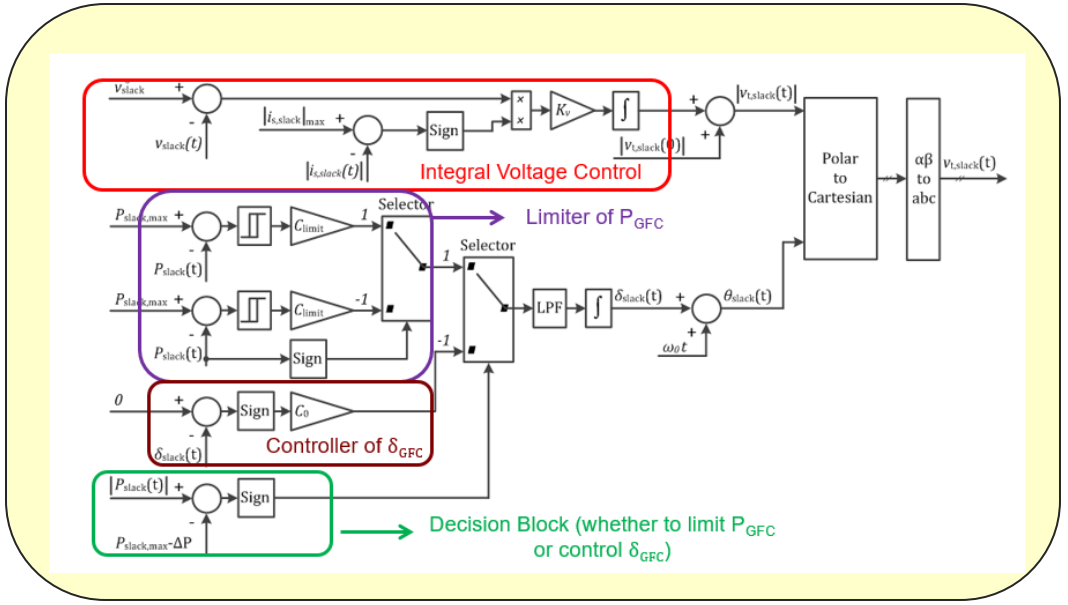
Modeling – Grid Forming Inverter in Constant Frequency Control Mode

Positive Sequence Model



- Suitable for bulk power system studies

EMT Model



- Developed three-phase EMT inverter models to investigate control design and implementation of constant frequency operation

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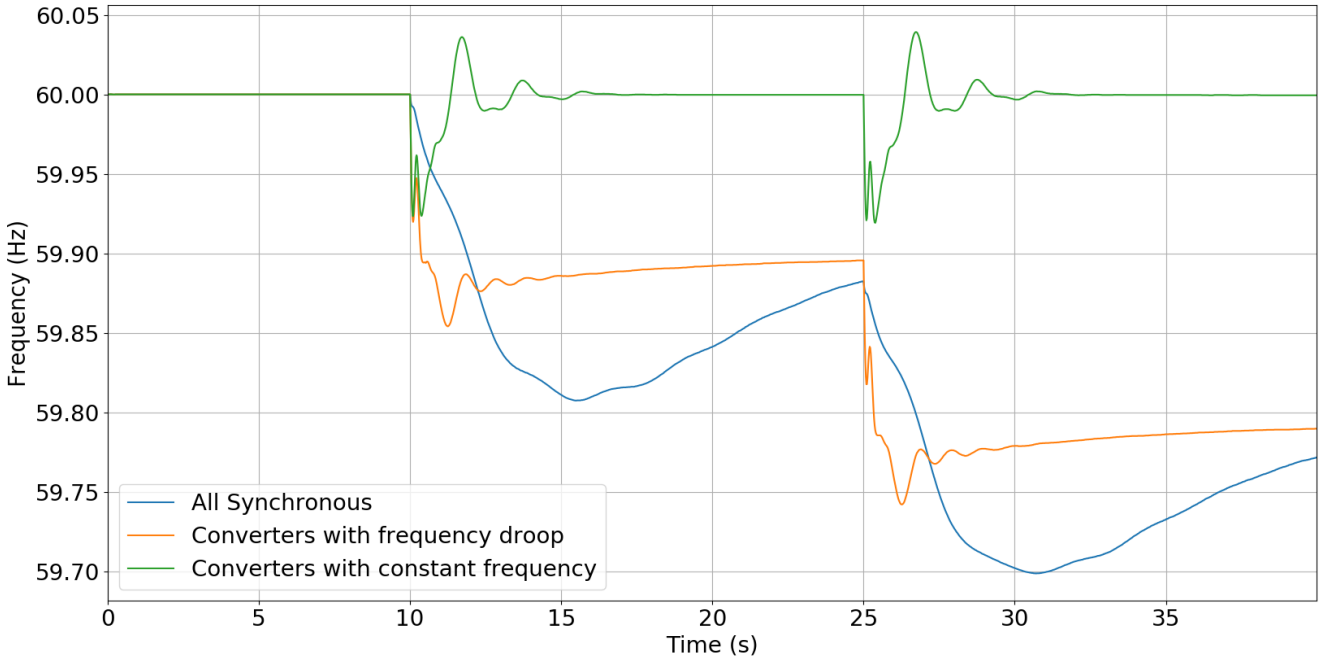
Demonstrating Results in Large Scale Systems

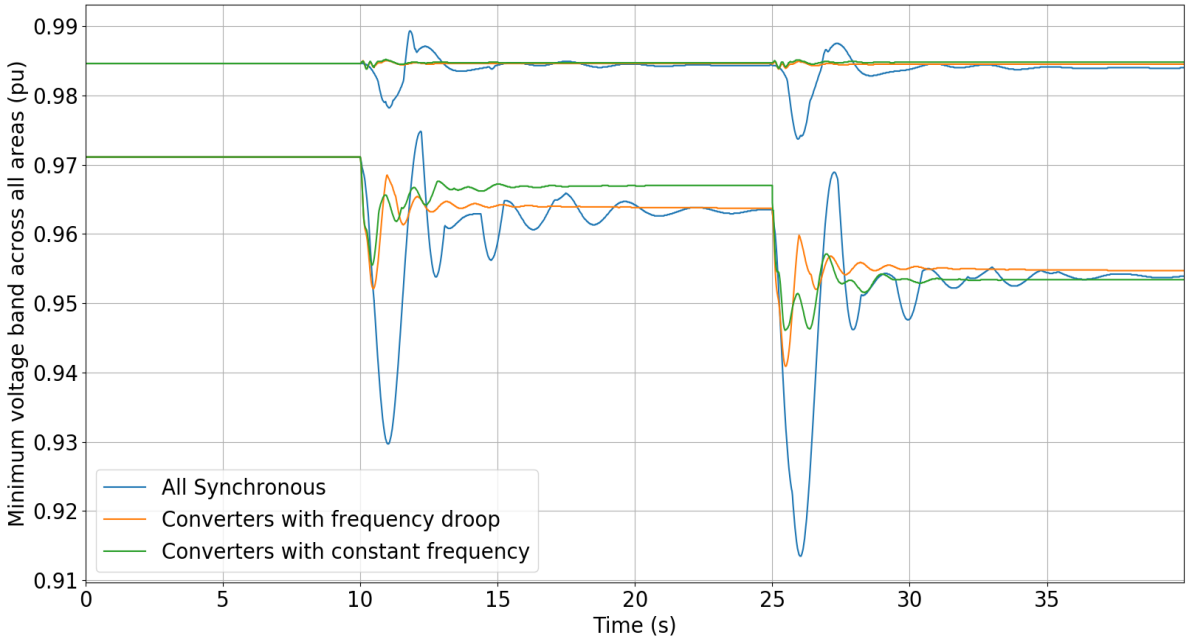
Evaluated stability and control performance through dynamic simulation of 2000 bus synthetic Texas system

- 3 Scenarios
  - All synchronous generators with governors
  - All inverter sources with frequency droop control
  - All inverter sources with constant frequency operation control

Generation Trip – Frequency Response



Generation Trip – Voltage Response



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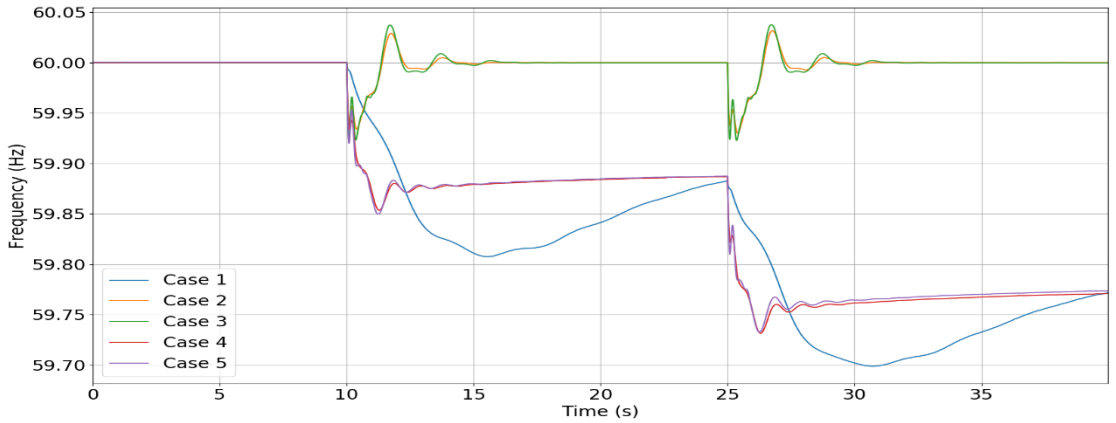
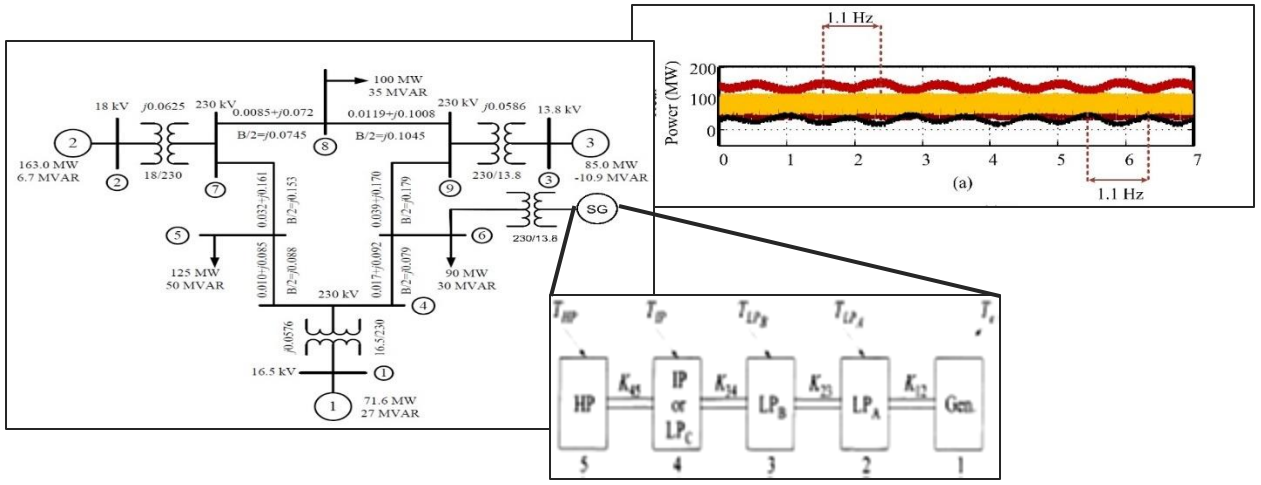
IBR Dominated System

- Investigated scenarios with small portion of generation provided by synchronous machines

	Source Type	Control Type
Case 1	All 433 synchronous machines	Simple governor and static excitation system
Case 2	417 grid forming converters	Constant frequency and voltage control
	16 synchronous machines	Simple governor and excitation system
Case 4	417 grid forming converters	Frequency droop and voltage control
	16 synchronous machines	Simple governor and excitation system



Synchronous Generator vs IBR Control Interactions



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Together…Shaping the Future of Electricity

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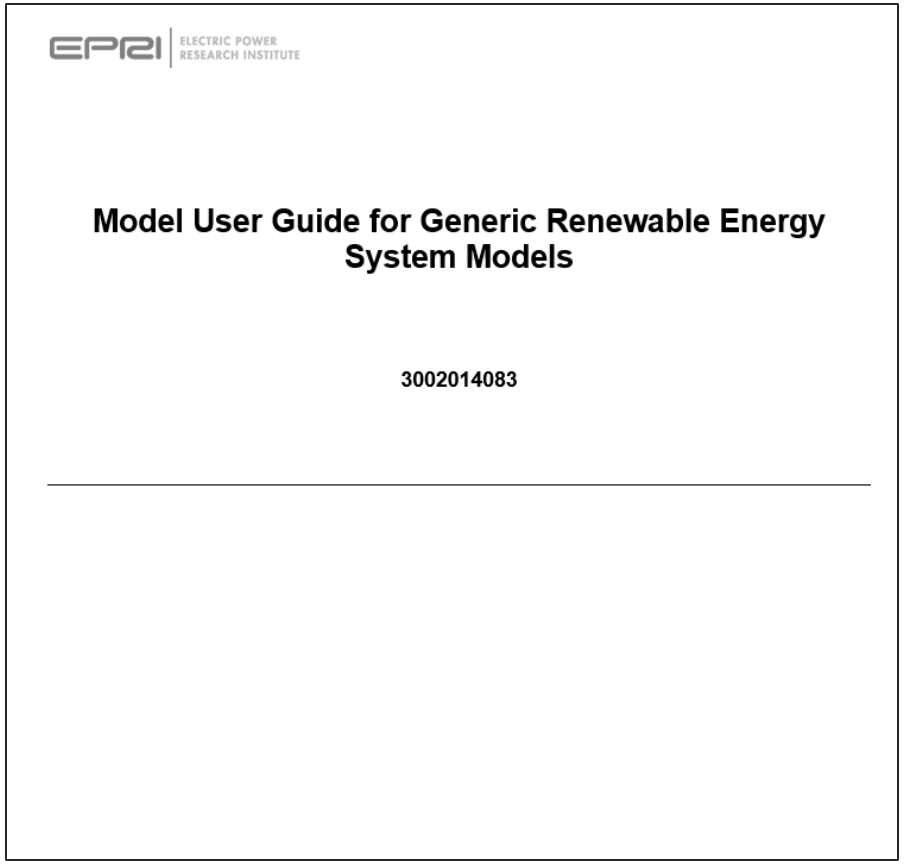
Model User Guide for Generic Renewable Energy System Models

- First version published in 2015
- Updated 2018 version includes:
  - additions to the library of generic utility scale renewable energy system models (e.g. the complex plant controller REPC_B)
  - table with typical values for RES models
  - comments received from EPRI members on edits and improvements to the document


EPRI ELECTRIC POWER RESEARCH INSTITUTE

Model User Guide for Generic Renewable Energy System Models

3002014083

Published at: https://www.epri.com/#/pages/product/000000003002014083/?lang=en

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NY Renewable Resource Capacity Information

NPCC Regional Standards Committee

5/16/19

G. Smith - NYSRC unaffiliated member

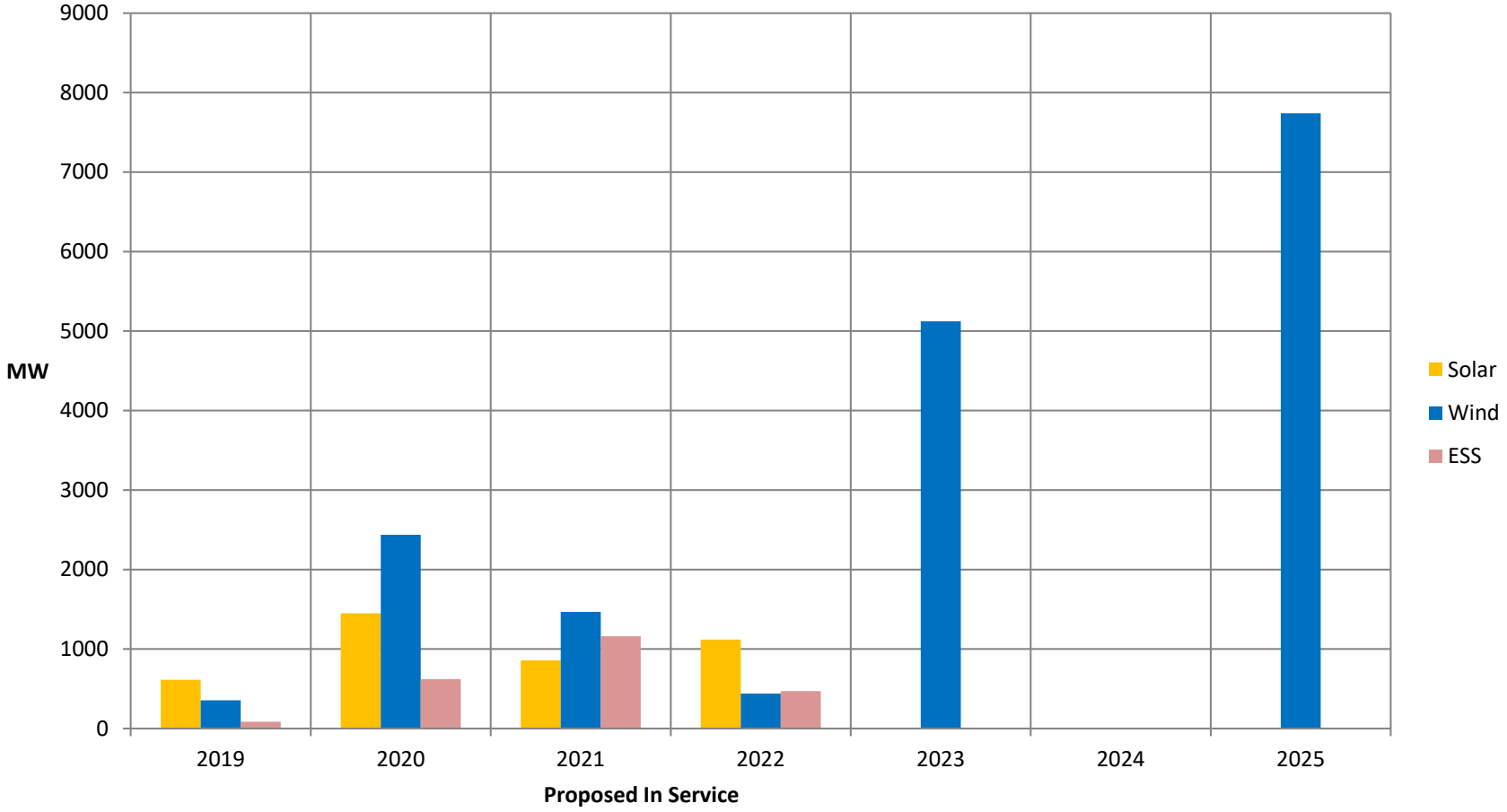
The information presented herein was obtained by sorting and extracting data from NYISO and NY DPS websites in an attempt to quantify potential renewable DERs that may impact behavior of the NY electric system

data (some needs update) subject to check
goal to get some level of approximation
original purpose to inform NYSRC EC

Future BES Connected Renewables

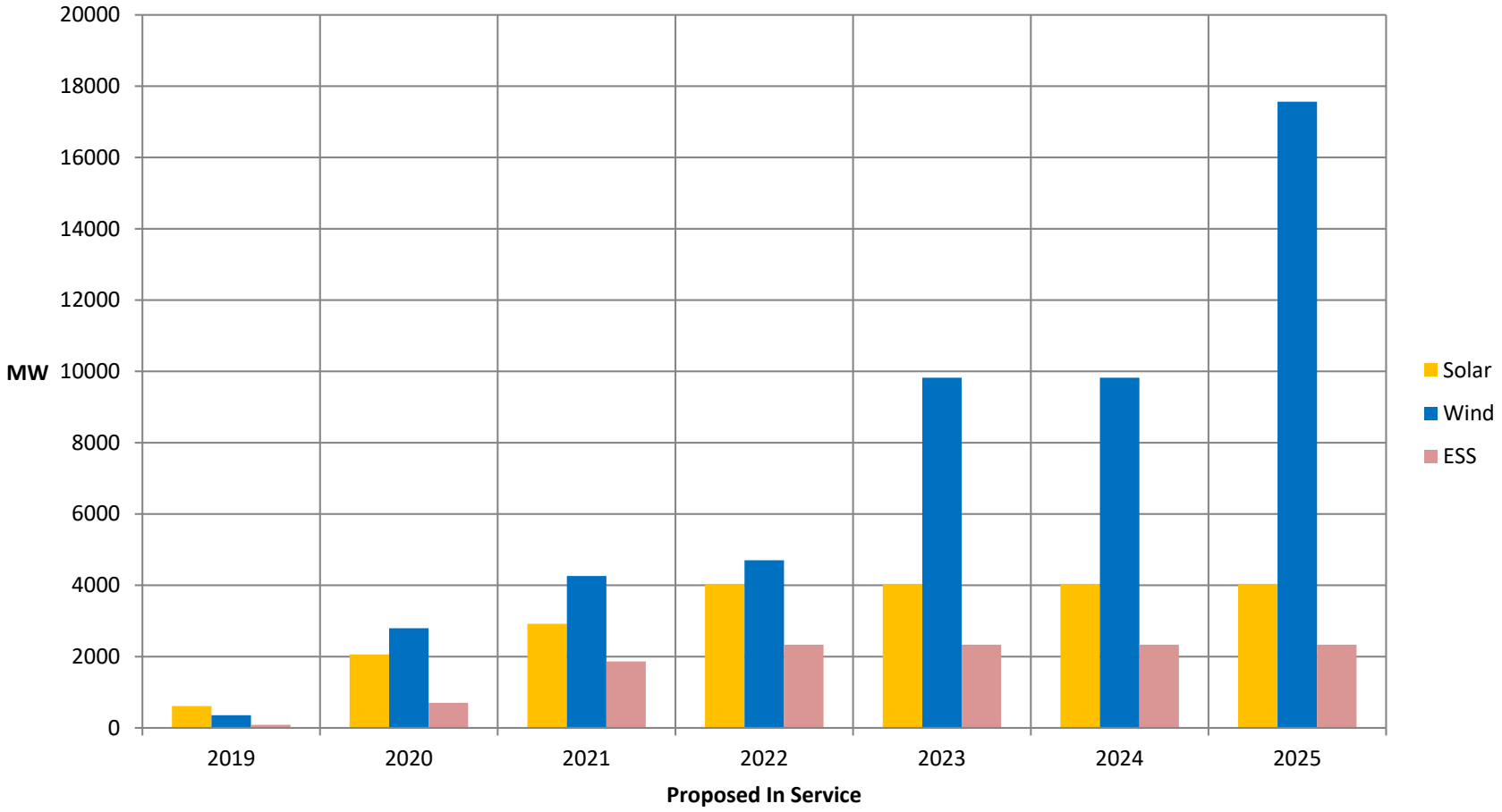
Renewables in NYISO Queue

as of 05/01/19



Cumulative Renewables in NYISO Queue

as of 5/01/19

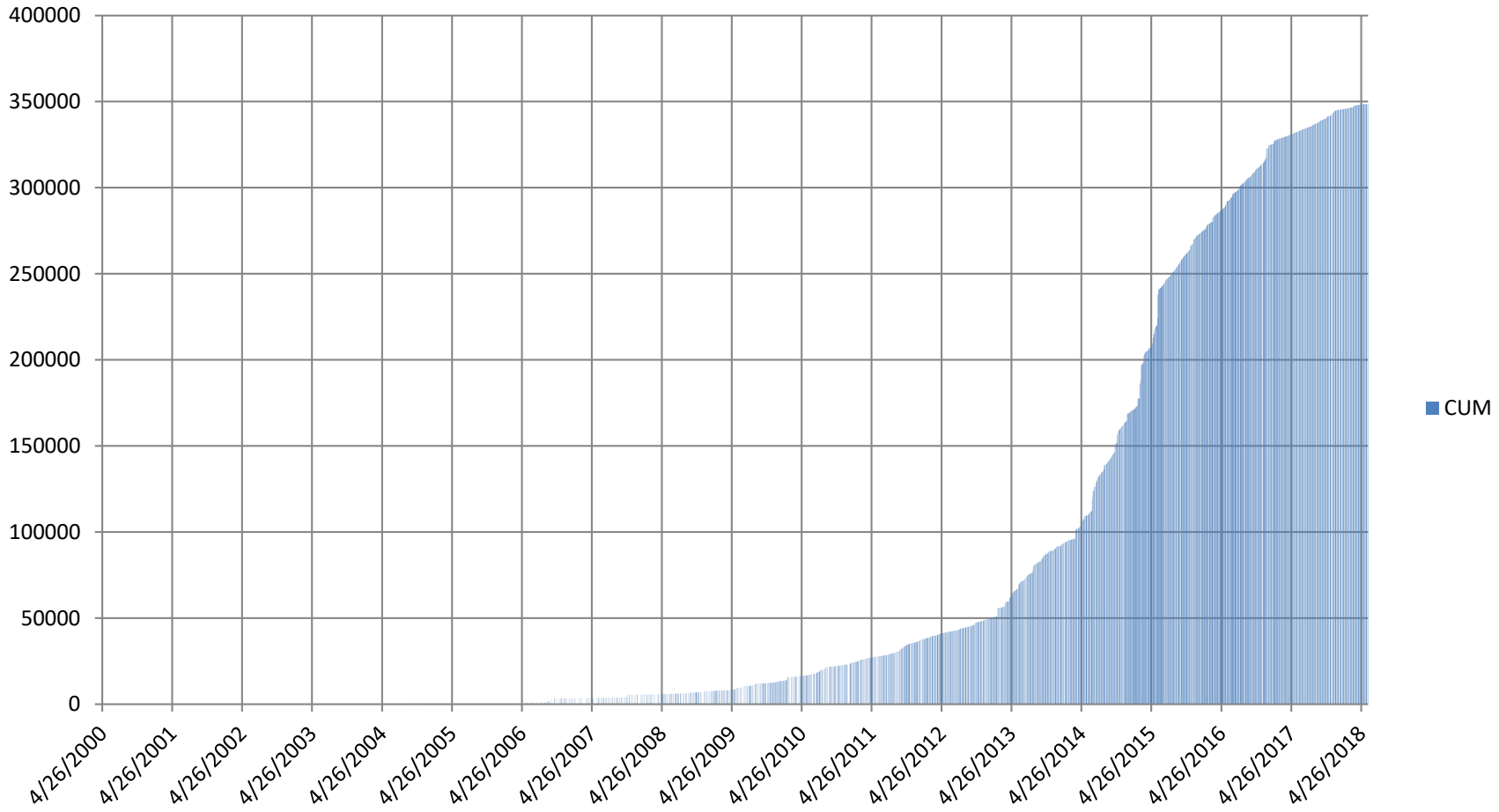


Behind the Meter

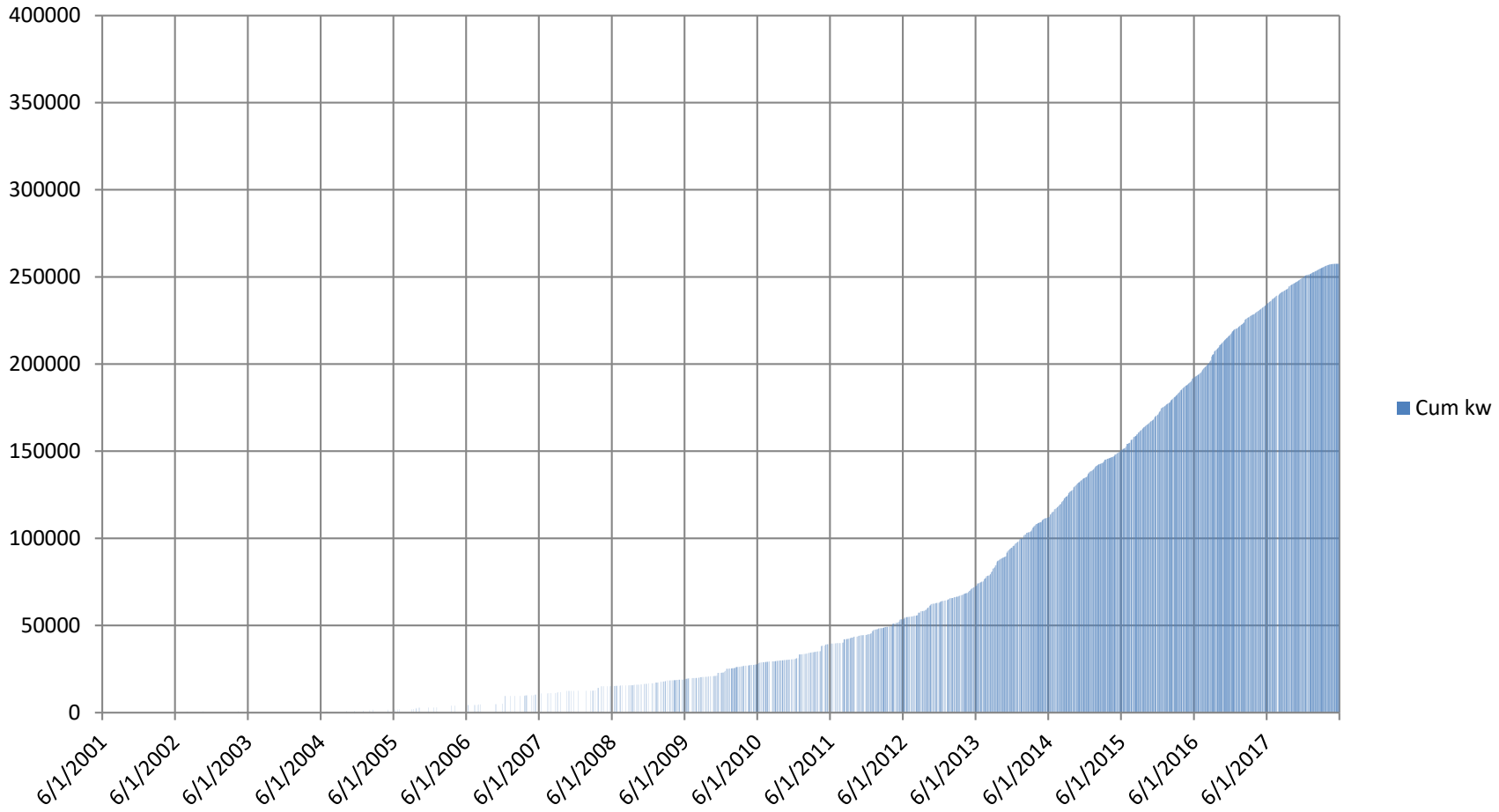
(Connected at distribution level)
Cumulative as of May 2018
Derived from NYDPS data
Mostly small solar

http://www3.dps.ny.gov/W/PSCWeb.nsf/All/286D2C179E9A5A8385257FBF003F1F7E?OpenDocument

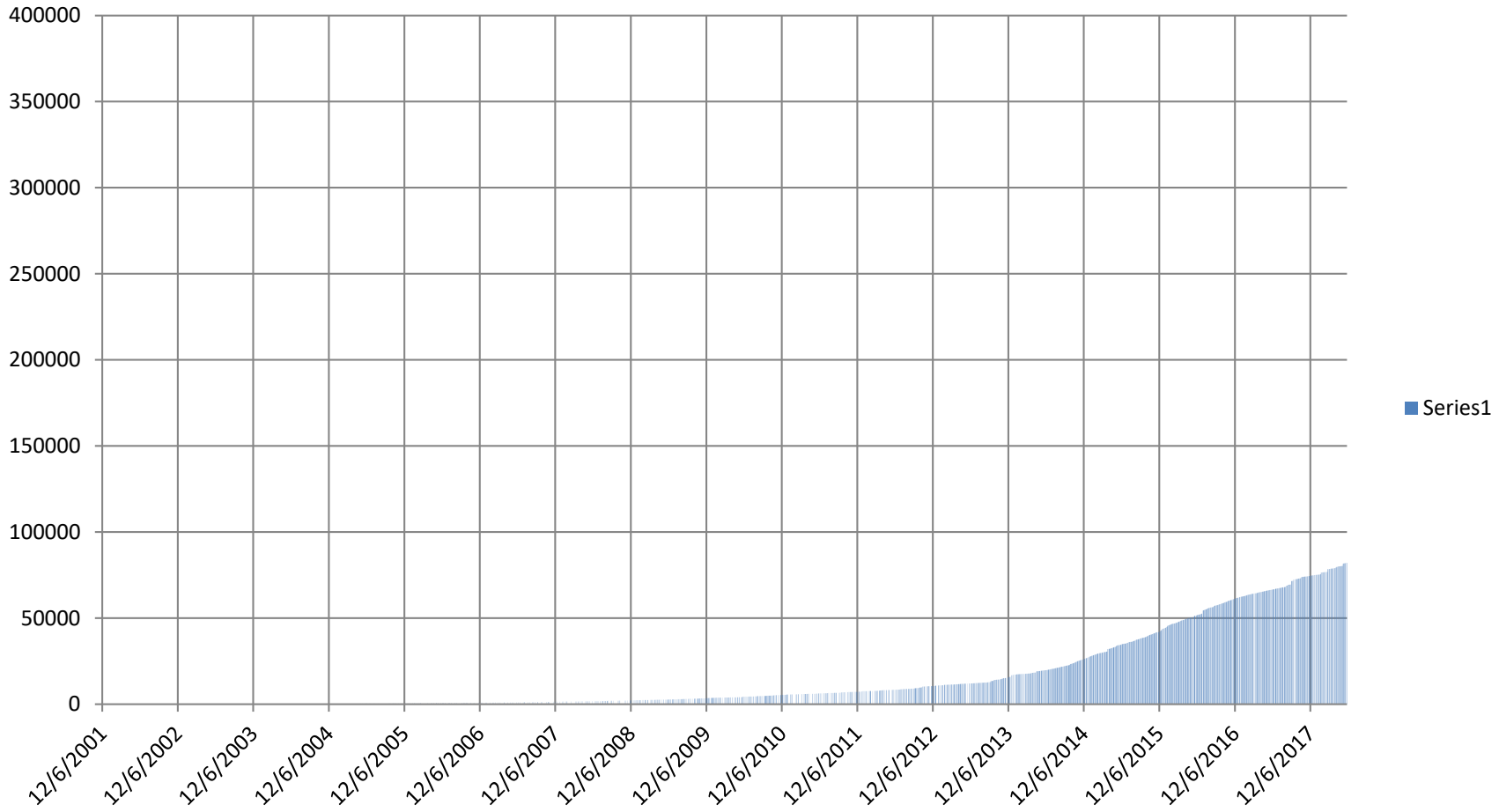
NGRID Cumulative kw



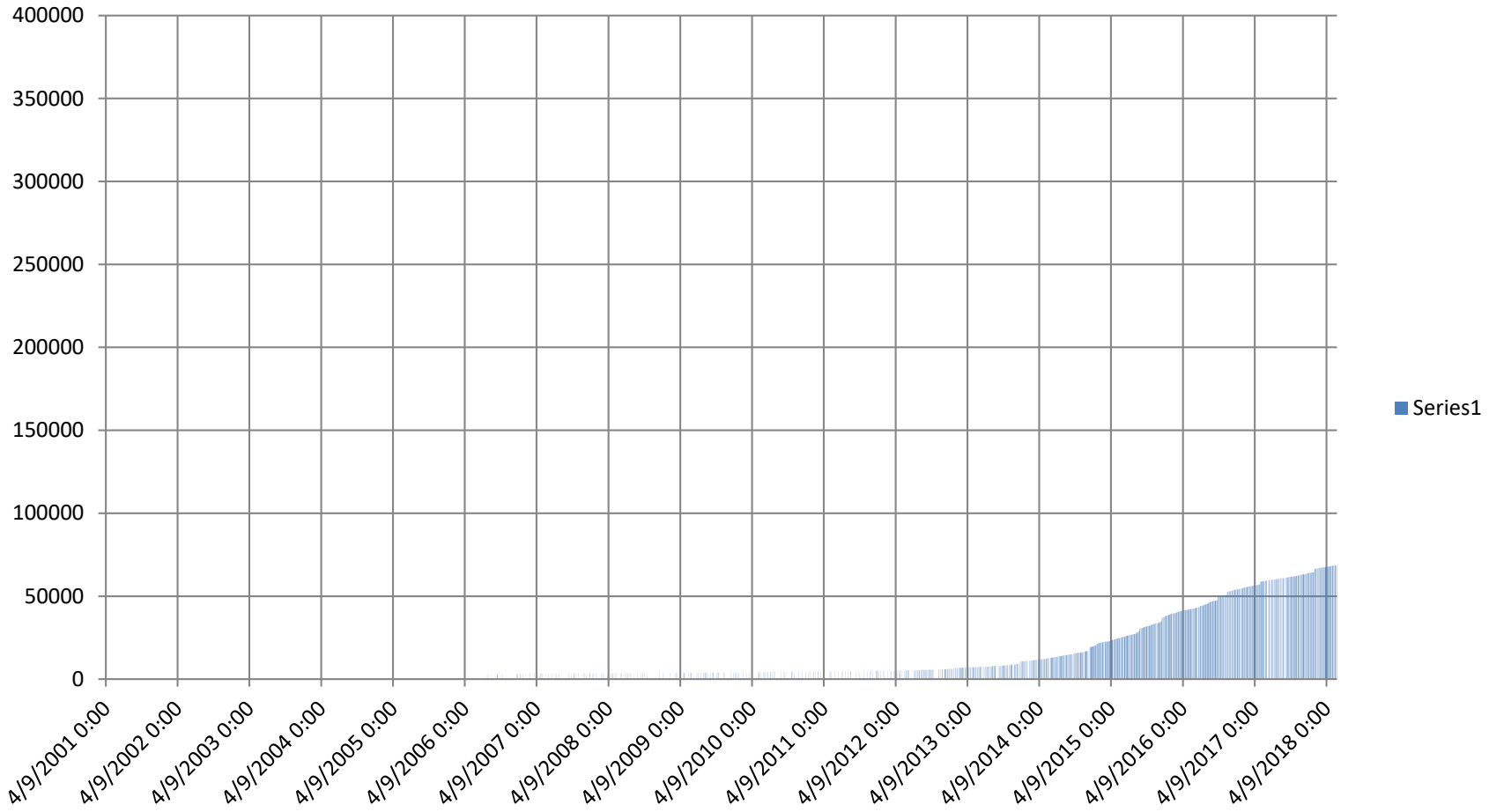
Con Ed Cumulative kw



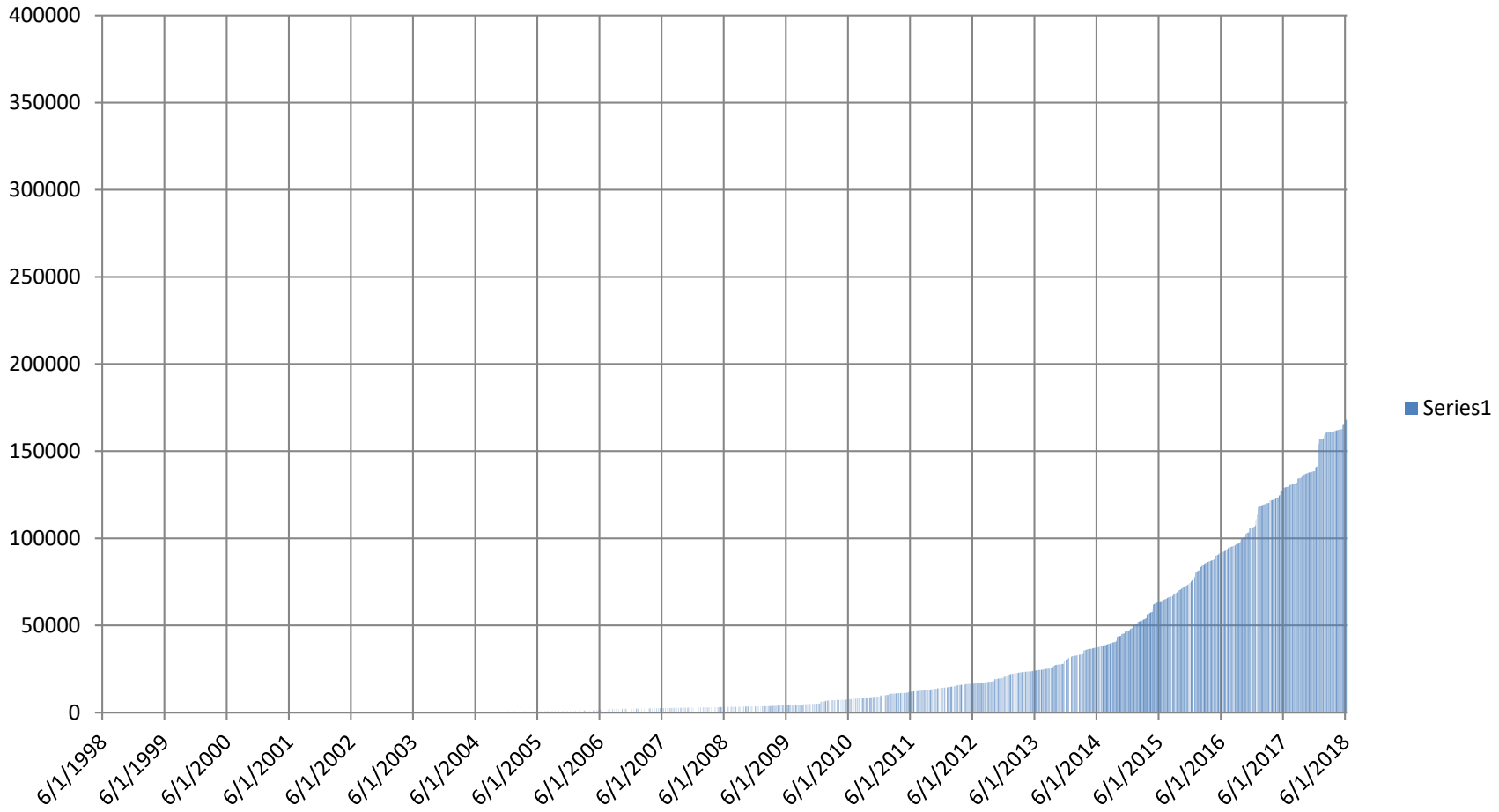
Cen Hud Cumulative kw



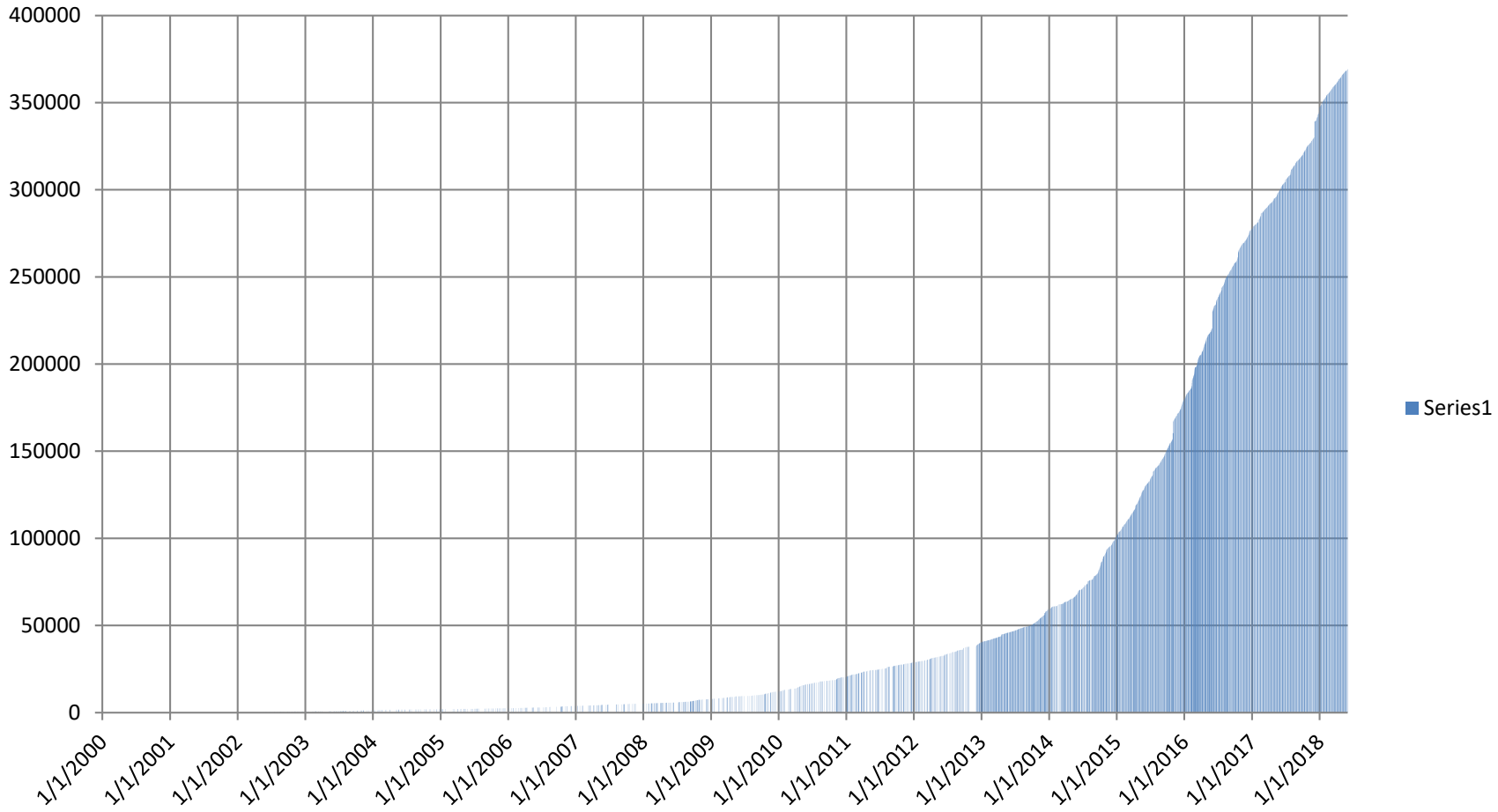
Orange & Rockland Cumulative kw



NYSEG/RG&E Cumulative kw



PSEG Cumulative kw



Existing as of May 2018

- **Statewide Total kw**
  - NGRID---------- 360,000
  - Con Ed ---------- 258,000
  - Cen Hud ---------- 82,000
  - Orange and Rockland --- 69,000
  - NYSEG/RG&E ---------- 168,000
  - PSEG LI ---------- 369,000
  - ----------
  - Total ---------- 1,306,000

Total Distribution Connected

Existing plus Queue
as of May 2018

Company	In Service kw	In Queue kw	Total kw
Ngrid	360,000	862,130	1,222,130
Con Ed	258,000	126,232	384,232
CenHud	82,000	177,862	259,862
O&R	69,000	136,209	205,209
NYSEG		358,959	358,959
RG&E	168,000	125,982	293,982
PSEG	369,000	113,507	482,507
Total	1,306,000	1,900,882	3,206,882

DER Summary

Projected Totals based on installed plus queues
How much in queues will actually go into service?

- **Solar**
  - **BPS – 4000 MW**
  - **Distribution – 3200 MW + (as of 5/18)**
  - **Total – 7200 MW**
- **Wind**
  - **BPS – 17600 MW**
  - **Distribution - probably small amount compared to BPS connected?**
- **Storage**
  - **BPS – 2300 MW**
  - **Distribution – 4950 (NYSEG) + other???**

Potential NY Variable Resources

- **Total Solar plus wind – Up to 24800 MW**
- **Storage (non hydro) – 7300+ MW**

DER Participation Model Market Design

James Pigeon
Manager, Distributed Resources Integration

NPCC Regional Standards Committee

May 16th, 2019, Hampton Inn, Saratoga Springs

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Agenda

- **DER Energy Market Design**
  - Overview & Purpose
  - Transmission Nodes
  - DER Aggregations: Overview, Rules & Participation
  - Bidding & Dispatch
  - Telemetry, Settlements & Metering

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Background - DER

Date	Working Group	Discussion points and links to materials
06-19-18	Market Issues Working Group (MIWG)	DER Market Design: Updates
07-26-18	Market Issues Working Group (MIWG)	DER Market Design Updates: Energy Market Bid to Bill Examples
10-09-18	Market Issues Working Group (MIWG)	DER Market Design Update: Wholesale Obligations for Dual Participation
10-10-18	Market Issues Working Group (MIWG)	DER Market Design Update
11-05-18	Market Issues Working Group (MIWG)	DER Market Design Updates
12-18-18	Market Issues Working Group (MIWG)	DER Overall Energy Market Design Review
02-04-19	Market Issues Working Group (MIWG)	DER Overall Energy Market Design Review Part I
02-06-19	Market Issues Working Group (MIWG)	DER Overall Energy Market Design Review Part II
02-28-19	Market Issues Working Group (MIWG)	DER Energy Market Design Dual Participation
03-18-19	Market Issues Working Group (MIWG)	DER Energy Market Design DR Cost Allocation
03-25-19	Installed Capacity Working Group (ICAPWG)	Expanding Capacity Eligibility
03-28-19	Market Issues Working Group (MIWG)	DER Energy Market Design: Settlements & Other Updates
04-08-19	Installed Capacity Working Group (ICAPWG)	Expanding Capacity Eligibility
04-17-19	Business Issues Committee (BIC)	DER Energy & Capacity Market Design
04-24-19	Management Committee (MC)	DER Energy & Capacity Market Design

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Overview & Purpose

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Purpose of the DER Roadmap Effort

- Develop and enhance participation opportunities for DER in the NYISO-administered wholesale markets by creating:
  - A DER Participation Model; and
- Create a model that supports the **NYISO Market Design Vision** - ***Attract and retain the most efficient resources to meet NY's reliability needs.***

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DER Definition for the Market Design

- Distributed Energy Resource ("DER"): (i) a facility comprising two or more Resource types behind a single point of interconnection with an Injection Limit of 20 MW or less; or (ii) a Demand Side Resource; or (iii) a Generator with an Injection Limit of 20 MW or less, that is electrically located in the NYCA.
- DER must be capable of responding in real-time to NYISO dispatch instructions.

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Transmission Nodes

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Transmission Node Overview

- The ISO, in coordination with the Transmission Owners, shall establish the set of Transmission Nodes in the New York Control Area
  - All Transmission Nodes will be identified in ISO Procedures
- Aggregators will work with Transmission Owners to determine which ISO identified Transmission Node each individual DER/Facility electrically maps to
  - Only DER/Facilities that map to the same Transmission Node may be aggregated together
- Aggregators may enroll one or more Aggregations at a Transmission Node

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Transmission Node Background

- Transmission Nodes reflect the collection of electrically similar facilities to which individual DER may aggregate as an Aggregation with a single PTID
- The DER Roadmap outlined the need to:
  - Consider all Transmission Nodes that allow the NYISO to best represent DERs impact on the transmission system
  - Deliver more granular pricing data to incent efficient locational investment

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NYISO Transmission Node Approach

- The NYISO considers individual DER to be small resources, often times distributed across multiple sites, often times connected to the Distribution system
- These individual DER would not normally have the ability to participate in NYISO Markets, when only taking into account their individual operating characteristics

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DER Aggregations: Overview, Rules & Participation

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DER Aggregation Approach

- Aggregations grouped at a Transmission node allow NYISO to effectuate dispatch in a manner that both sends correct price signals and effectively relieve transmission constraints on the system
  - This Transmission Node level granularity, instead of Load Zone level, will more effectively relieve transmission constraints thereby resulting in lower overall total production cost

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DER Market Participation

- **The DER participation model will only be available to Aggregations**
  - An Aggregation consists of two or more individual resources, except that Demand Side Resources and individual facilities that can reduce load and inject energy (i.e., transition from being Load to Supply without an infeasible operating range), will be permitted to individually use the DER participation model as a single-resource Aggregation
- **Individual facilities in an Aggregation will participate under the market rules for either:**
  - A DER Aggregation (when there are multiple Resource types in the Aggregation), or
  - The specific Resource type (when there is a single Resource type in the Aggregation)
    - For an Aggregation of Intermittent Power Resources, the technology type of each Resource in the Aggregation must be the same (E.g., Resources depending on wind as their fuel)

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Basics for all Types of Aggregations

- Resources will be permitted to aggregate to meet minimum requirements and performance obligations for eligible participation models
- The Aggregator will be the NYISO Market Participant
- The Aggregation will be a group of one or more resources participating in the NYISO Market, represented by a PTID
  - Bids will represent the offer of the Aggregation
  - Performance will be measured in aggregate
  - Financial settlements will be in aggregate
    - NYISO intends to separately process the injection, withdrawal and load reduction data to ensure accurate settlements

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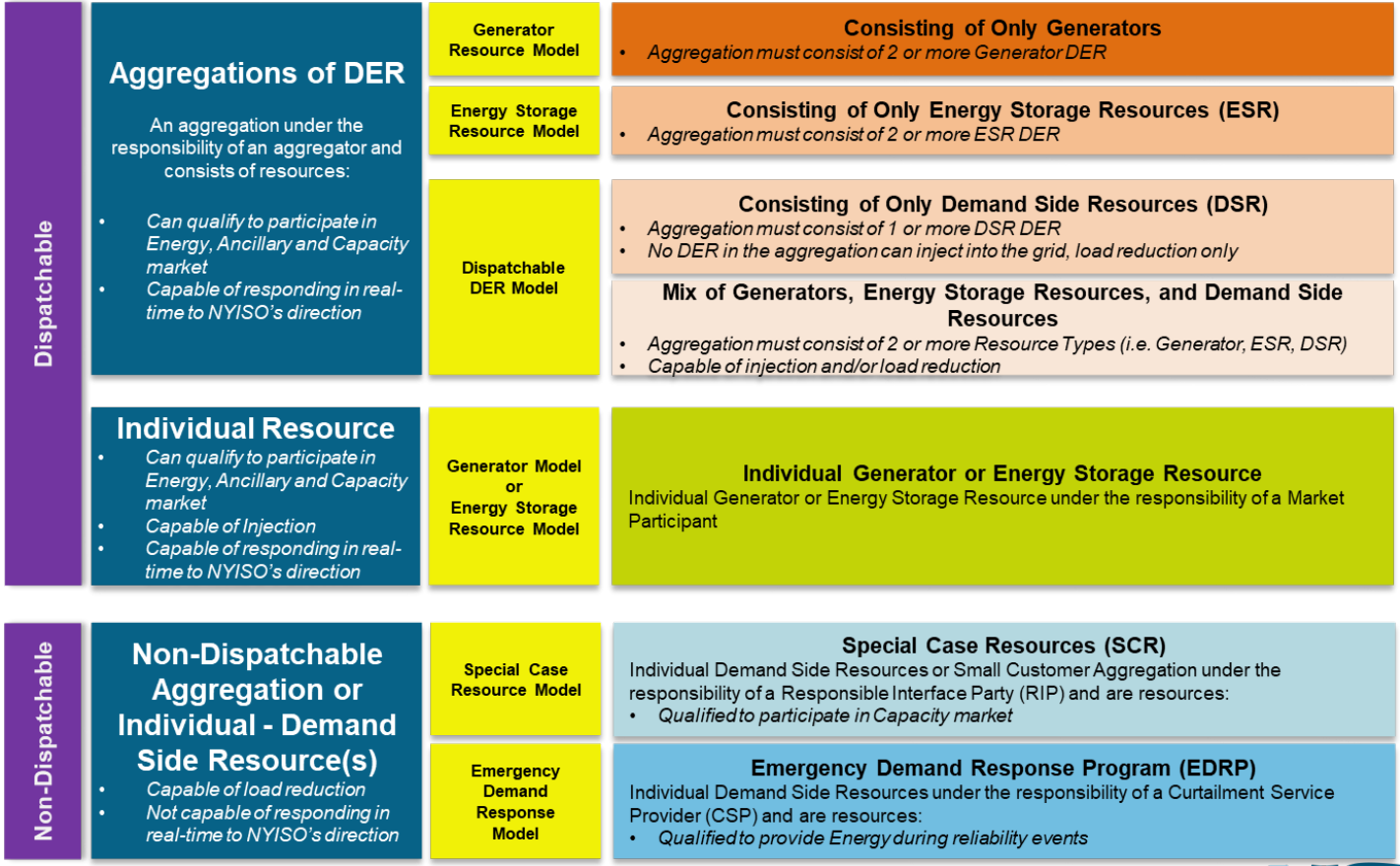
Participation Models Available to DER



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Aggregation & Ancillary Services

- **Aggregations will be eligible to supply the Ancillary Service Products for which all DER within the Aggregation are eligible to supply**
  - Example 1: An Aggregation would be eligible to supply Regulation only if all DER in the Aggregation are eligible to supply Regulation
  - Example 2: If one resource in the Aggregation is only eligible to supply 30 Minute Non-Synchronous Reserves, the entire Aggregation is only eligible to supply 30 Minute Non-Synchronous Reserves

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Aggregation & Ancillary Services, con't

- Aggregations will be dispatch only and the NYISO will only have the real-time visibility of the operating state of the entire Aggregation as a whole
  - NYISO will not have real-time visibility to the operating status of individual DER
- Compliance with Northeast Power Coordinating Council standard requires that synchronous reserves can only be awarded to resources that are synchronized to the electric grid[1]
- Aggregations containing generator-based DER will only be eligible to provide Non-Synchronous Operating Reserves because the NYISO will not know real-time visibility of the grid synchronization operating state of the individual generator-based DER within the Aggregation

[1]NPCC Glossary of Terms: https://www.npcc.org/Standards/Directories/Glossary%2020171103.pdf

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Interconnection for DER

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Interconnection for DER

- **Interconnection (ERIS) and CRIS Requirements will Focus on the Facility (not the asset or aggregation)**
  - A multi-technology DER facility may submit one IR in the Small Generator Interconnection Procedures for both ERIS and CRIS
- **NYISO proposes to redefine what may be included in one Interconnection Request (IR) (*i.e.*, a single queue position in the interconnection queue)**
  - Revisions to both the Material Modifications and Permissible Modifications sections to account for DER
    - Material Modifications (requiring a new Interconnection Request)
    - Permissible Modifications (not material, but may require IA amendments)
    - Details included in Appendix

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Some DERs Will Not be Subject to NYISO Interconnection Procedures

- **NYISO's interconnection procedures govern the interconnection of the facility if:**
  - Developer intends to make wholesale sales and
  - Developer proposes to interconnect to (i) transmission or (ii) distribution facilities on which there is already a generator making wholesale sales *(i.e.*, "FERC-jurisdictional distribution")
- **NY Standardized Interconnection Requirements (SIR) govern the interconnection of the facility if:**
  - Developer is interconnecting to portions of the distribution system other than "FERC-jurisdictional distribution" and the resource is less than or equal to 5 MW
- **Utility interconnection procedures govern the interconnection of resources if the interconnection is not subject to the NYISO or SIR processes**
  - Interconnection Service for SIR or Utility-level interconnection is based on the applicable interconnection agreement
  - Facilities that proceed through the SIR or utility interconnection processes must have an interconnection agreement that allows wholesale sales

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Bidding & Dispatch

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DER Bidding, Approach

- All DER Aggregations, regardless of resource mix, will be bid into the Energy market place and settled as a single entity
- The distinction for the settlements process, as it will pertain to Revenue Metering and Telemetry, will be that the NYISO will account for the following aspects of each DER Aggregation when evaluating performance:
  - Energy Injection from Generation units
  - Demand Reduction provided as Supply from Demand Side Resources
    - To account for FERC Order No. 745
  - Energy Withdrawal from Withdrawal-Eligible Generators

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Telemetry, Settlements & Metering

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Aggregation Telemetry

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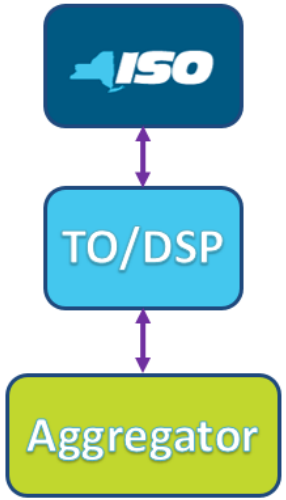
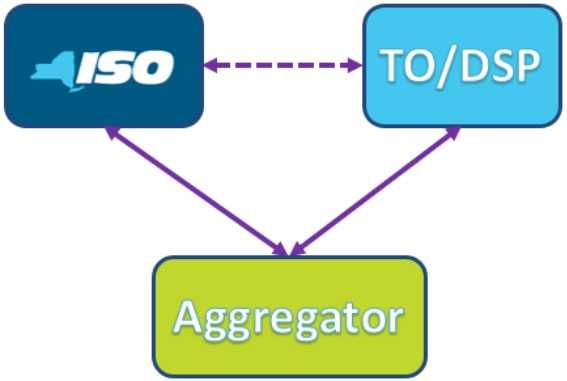
Options for Real-time Telemetry Data Communication Paths

Option 1 – Aggregator communicates only with DSP and DSP provides data to/from NYISO



Option 2 – Aggregator communicates with both DSP and NYISO in parallel



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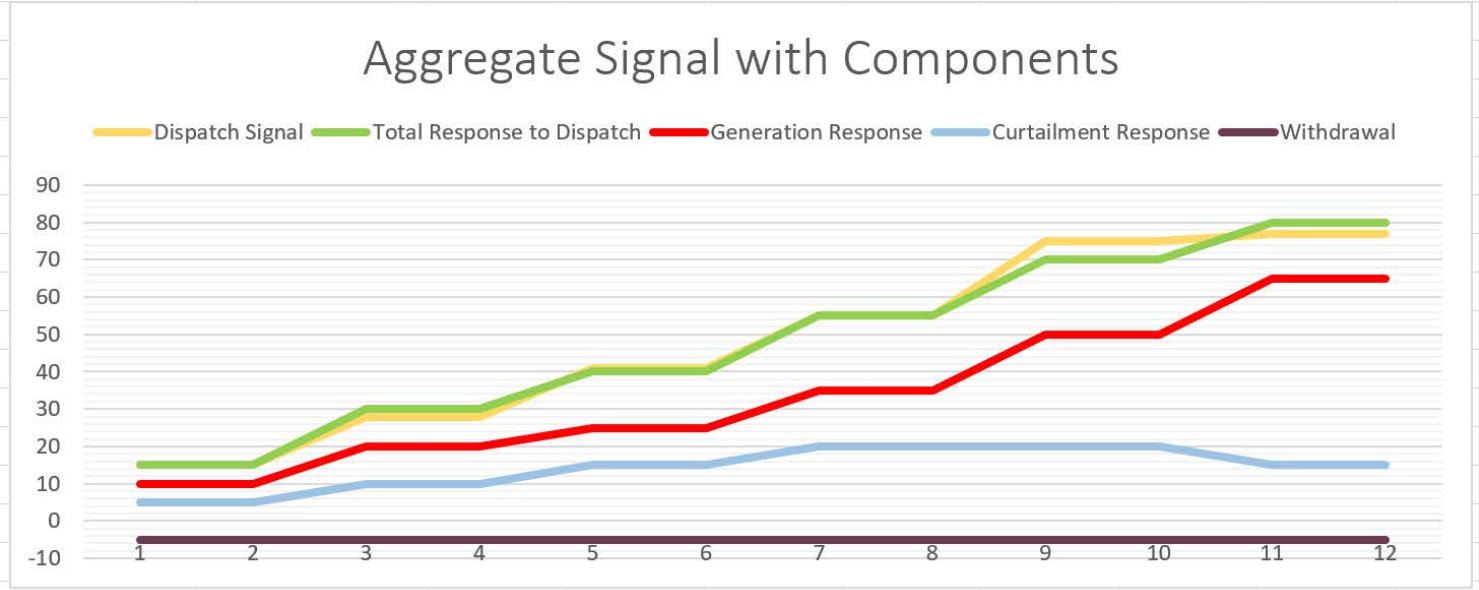
Aggregate Response Signal with Individual Components



- This example contains the NYISO dispatch signal, the aggregate response signal and the sub-component signals for settlements

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Real-Time Telemetry & Settlement Data

- **Similar to Generators participating in the NYISO markets today, the Aggregation will be required to send all telemetry signals for 24 hours of the day, 7 days a week**
  - This will be required regardless of dispatch schedule, for the independent signals for:
    - Aggregation aggregate signal, and;
    - Aggregation aggregate Injection, and;
    - Negative Generation (when an Aggregation eligible to withdraw Energy is dispatched to withdraw), and;
    - Aggregation aggregate Load Reduction
- **The aggregator will need to measure the injection, withdrawal and the load reduction of all DER within the Aggregation, during dispatch**
  - This will be done regardless of utilization of assets for meeting dispatch
  - This applies to both real-time telemetry and settlement data submission

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Real-Time Telemetry Requirements for Power System Operations: 6-Second Scan Rate

One of NYISO's responsibilities is maintaining the reliability of the New York Bulk Power System and timely information on market resource performance supports this mission. 6-second telemetry of resources participating in NYISO's market is crucial to effectively maintain the reliability of the grid.

- Real-time telemetry updated every 6 seconds provides essential two-way communication of operational data between market resources and NYISO
- NYISO relies on real-time telemetry for situational awareness necessary to balance supply and demand within the New York Control Area (NYCA), and to identify and respond to normal and abnormal conditions

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Dual Participation

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Dual Participation

- **The NYISO's proposed market design will allow resources that provide Wholesale Market services to also provide services to another entity (*e.g.,* the utility or a host facility)**
  - The NYISO believes that providing resources with the flexibility to meet wholesale and distribution system needs will deliver the maximum benefit to New York electricity consumers
  - Resources participating in the wholesale markets will continue to be obligated to follow all applicable NYISO market rules and utilize good utility practices
- **Dual participation concept applies to all resources, not just DER Aggregations**
  - Effective May 1, 2020 (and upon acceptance by FERC), Generators and Demand Side Resources electrically located in the NYCA may simultaneously participate in the ISO-administered wholesale markets and in programs or markets operated to meet the needs of distribution systems located in the NYCA.

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Requirements

- **Dual participating resources will be required to:**
  - Comply with all NYISO market rules for the services offered to the wholesale market
    - Non-compliance may result in financial penalties
  - Appropriately offer into the wholesale markets to reflect any non-wholesale (e.g., retail) obligations
    - Resources will be required to follow NYISO dispatch instructions at all times;
    - Resources will submit offers to NYISO when providing non-wholesale service
      - Based on resource type and market product enrollment, the offer may denote “Self” or “ISO”-Committed mode
    - Resources will receive payments for Energy or Ancillary Services scheduled through these offers

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Capacity Suppliers with duration limitations

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ICAP Suppliers

- **A resource must not have any daily duration limitations to qualify as a Capacity Supplier**
  - Have a minimum injection capability of 1 MW for traditional resources, 0.1 MW for ESR or DER resources
  - Receive 100% capacity payment
  - Subject to most existing qualification requirements
- **A resource that has a daily duration limitation may qualify as a Resource with an Energy Duration Limitation**
  - Have a minimum injection capability of 1 MW for traditional resources, 0.1 MW for ESR or DER resources
  - Receive capacity payment as applicable for resource's duration

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ICAP Supplier Payment Structure

- **The NYISO's proposed capacity values for duration limited resources**
  - These rules will be effective for the 2021-2022 Capability Year

	Incremental Penetration of resources with duration limitations	
Durations (hours)	Less than 1000 MW	At and Above 1000 MW
2	45%	37.5%
4	90%	75%
6	100%	90%
8	100%	100%

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Capacity Value Study

- **The NYISO will review the Capacity Values in 2022-2023, with results from the future study implemented in the 2025-2026 Capability Year**
  - Going forward, the NYISO is proposing to review the Capacity Values every 4 years with a 205 filing
    - Results of the Capacity Value Study will be submitted with the 205 filing, including any potential changes to the durations, capacity values, and Peak Load Windows
    - The duration of the Peak Load Window (used for B/S/N obligation, derating factor calculation, etc.) will be tied to the lowest duration eligible for 100% capacity payment
  - The Capacity Value Study will be reoccurring starting two years before the Demand Curve Reset process begins (every 4 years) (*e.g.*, 2022, 2026, etc.)

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Peak Load Window

- **Capacity Suppliers with duration limitations must be available during a predefined Peak Load Window**
  - The Peak Load Window for Winter and Summer Capability Periods are different
    - The 6 hour window is applicable for incremental penetration of resources with duration limitations less than 1000 MW
      - Winter: HB 16 – 21
      - Summer: HB 13 – 18
    - The 8 hour window is always applicable to resources that elect an 8-hour duration limitation, and will be applicable to all duration limited resources for incremental penetration of resources with duration limitations equal to or greater than 1000 MW
      - Winter: HB 14 – 21
      - Summer: HB 12 – 19

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Bid/Schedule/Notify

- **Capacity Suppliers with duration limitations are required to Bid/Schedule/Notify during the Peak Load Window**
  - The Bid/Schedule/Notify requirements differ based on the participation model of the resource

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Qualifications

- **Qualifications for Capacity Suppliers with duration limitations**
  - Resources must be electrically located within the NYCA
  - Have a minimum injection capability of 1 MW for all resources, excluding ESR and DER where the minimum injection capability is 0.1 MW
  - Resources will be allowed to derate and/or time stack to aggregate to meet a certain duration requirement
  - Performance-based generators (Wind, Solar, RoR Hydro) will not be eligible for a duration limitation

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Aggregations – Obligations

- **Obligations of Aggregations**
  - Bid/Schedule/Notify obligations will be based on the characteristics of the Aggregation
  - The NYISO will require the DER to perform a DMNC test once every Capability Period for the Aggregation as a whole
    - More detail in Appendix of BIC 4/17/19 Presentation
  - The method for calculating the derating factor for a DER will be based on the characteristics of the DER by treating the DER as a single resource
    - Derating factors for DER will be measured on the availability or performance of the Aggregation as a whole, as appropriate for that participation model

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Aggregations – Resources Changing Aggregations

- **Resources that switch Aggregations but remain within the same participation model can switch on a monthly basis**
  - Existing resources will carry their previous DMNC with them
- **Resources that switch between participation models or wholesale/retail participation must do so at the beginning of the Capability Year**
  - Existing wholesale market participants must notify the NYISO of this change prior to August 1st of the year preceding the Capability Year
  - Resources that switch between participation models will carry their previous DMNC with them

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Feedback?

- Email additional feedback to: DER_Feedback@nyiso.com

Don’t forget the underscore

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For further details:

DER Energy Market Design: Part 1 (02/04/2019 MIWG)

DER Energy Market Design: Part 2 (02/06/2019 MIWG)

DER Energy & Capacity Market Design (04/17/2019 BIC)

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Appendix

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Transmission Nodes - Identification

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Transmission Node Pricing and DER Mapping

- **Transmission Nodes will be priced individually, similar to generator nodes**
- **Transmission Node pricing will be calculated using the same LBMP calculation today:**
  - LBMP=Marginal Energy + Transmission Congestion – Losses
- **Transmission Nodes are for the purpose of wholesale market participation**
  - The NYISO proposes to coordinate with the local distribution utility to manage any distribution level constraints in the process of identifying the electrical bounds of each Transmission Node

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Load Nodes

- Load Nodes provide the most detail to the NYISO model
  - Load nodes are associated with distribution stepdown transformers at facilities below the transmission level NYISO currently secures
- While below a kV level that NYISO currently secures, DER interconnected at Load Nodes will face congestion and loss characteristics reflective of the transmission facilities that feed the load
- Load Nodes can be “mapped” up to the transmission system, but vary in paths based on the particular distribution owner service territory

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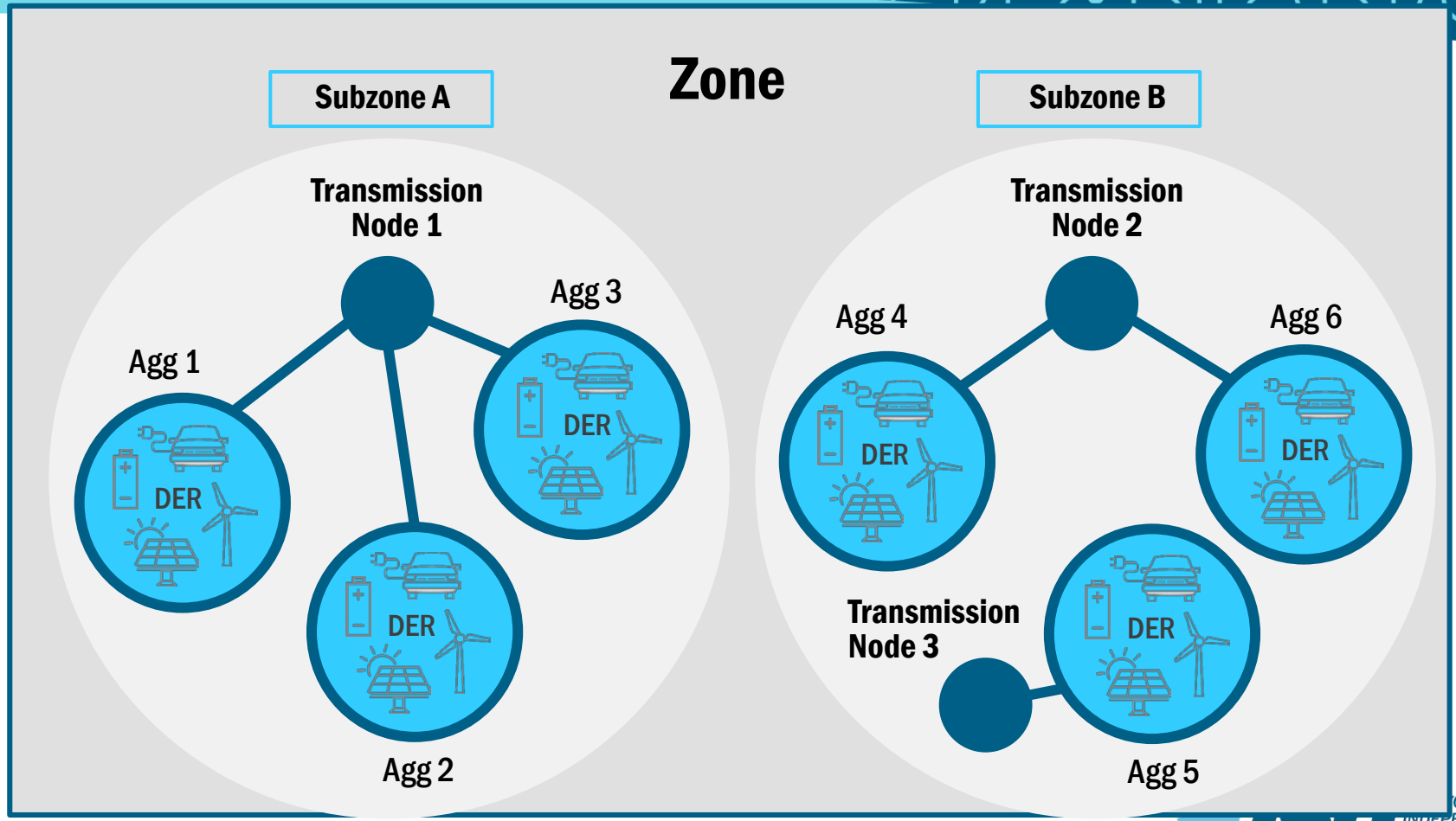

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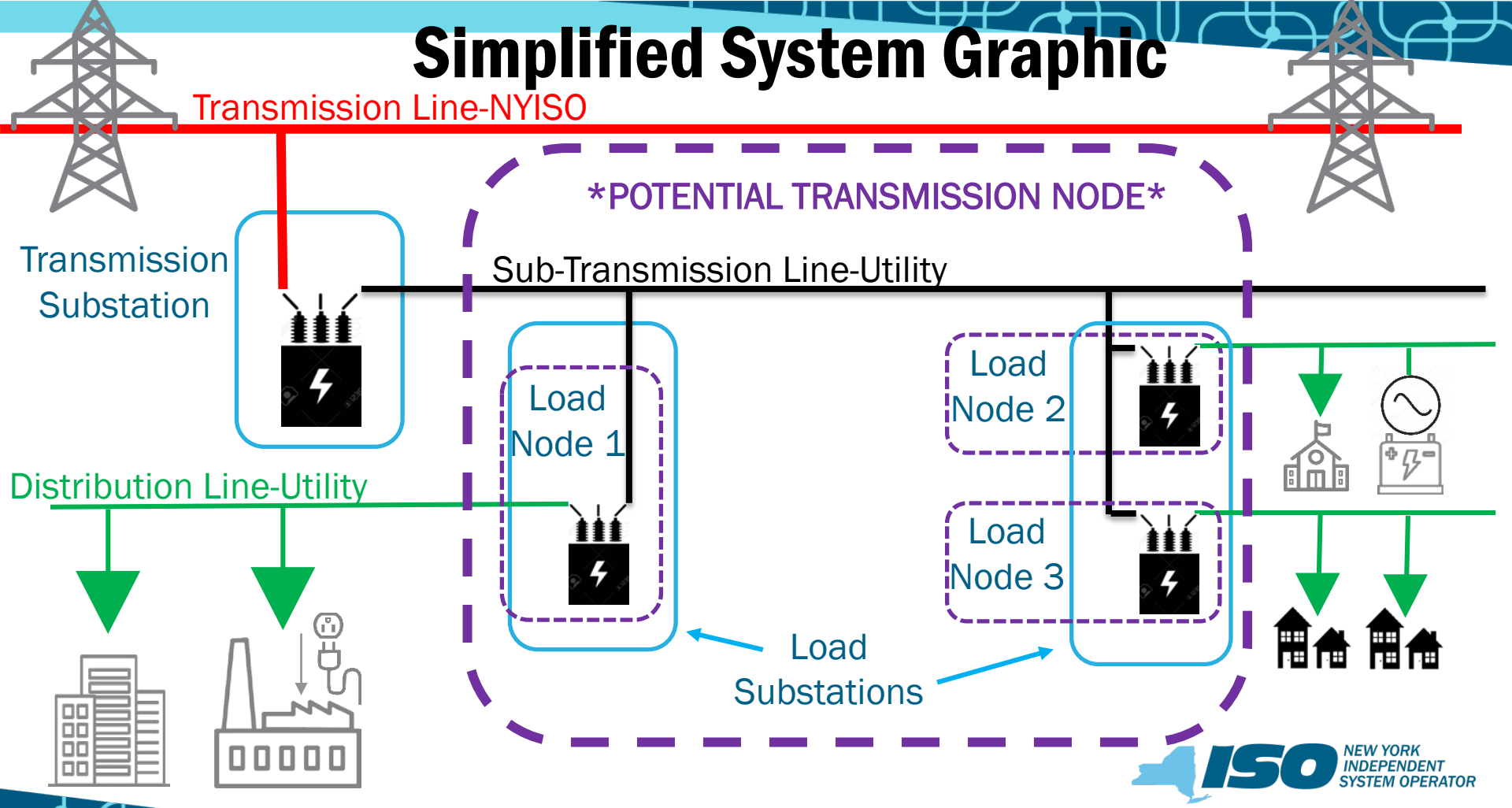
Simplified System Graphic



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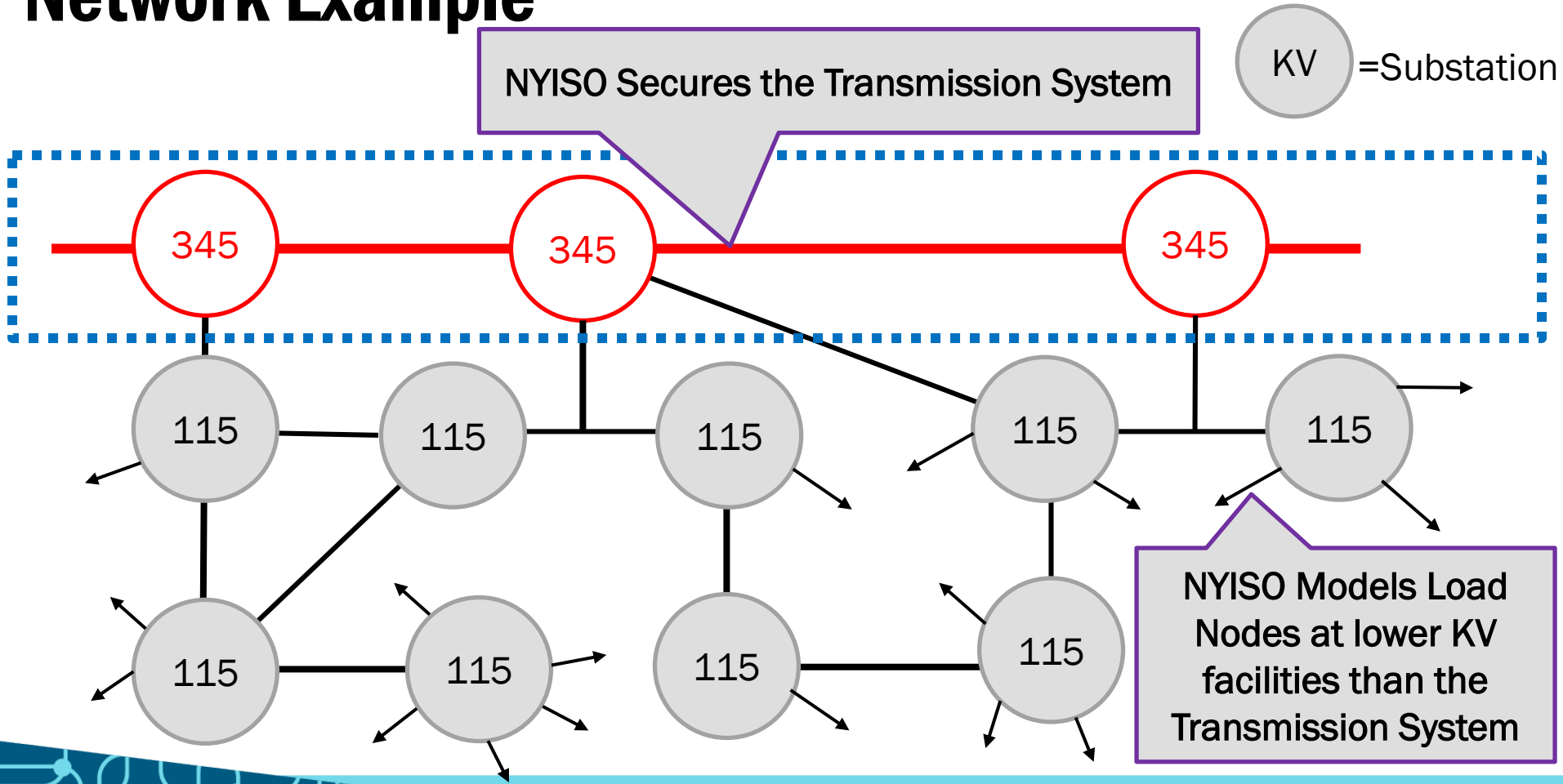
Network Example



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NYISO Process

- **The NYISO will utilize a tiered evaluation of Load Nodes used by the NYISO and the Utilities to define each Transmission Node**
- **The NYISO will identify all transmission-connected substations with associated Load Nodes**
  - Those substations will be evaluated to be a potential Transmission Node
  - The NYISO will identify radially bused substations as instances where substations may be grouped as a single Transmission Node
- **NYISO will additionally identify the step-down interfaces from the bulk electric system**
  - These interfaces will indicate the minimum Transmission Nodes needed to represent bulk transmission conditions within each zone

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NYISO Process, cont'd

- **In the final step, the NYISO and the Utilities will identify distribution facilities on the distribution system that may be may be negatively impacted if DER aggregations are dispatched as a single PTID across such facilities**
  - These constraining distribution facilities might be:
    - Normally open circuits
    - Line overload potentials
    - Franchise demarcations
  - Once identified, distribution constraints will delineate the electrical bounds of either an expanded or constricted Transmission Node
- **No interfaces identified in the 100+ kV project may be grouped with other Load substations in a Transmission Node**
- **Transmission Nodes will be Utility and Sub-Zone specific**

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The Mission of the New York Independent System Operator, in collaboration with its stakeholders, is to serve the public interest and provide benefits to consumers by:

- Maintaining and enhancing regional reliability
- Operating open, fair and competitive wholesale electricity markets
- Planning the power system for the future
- Providing factual information to policymakers, stakeholders and investors in the power system

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IEEE 1547/NERC PRC-024

NPCC Regional Standards Committee
5/16/19

Some Comparisons of Operation, Ride Thru and Trip Specifications Inverter Based DER's

G. Smith - NYSRC unaffiliated member

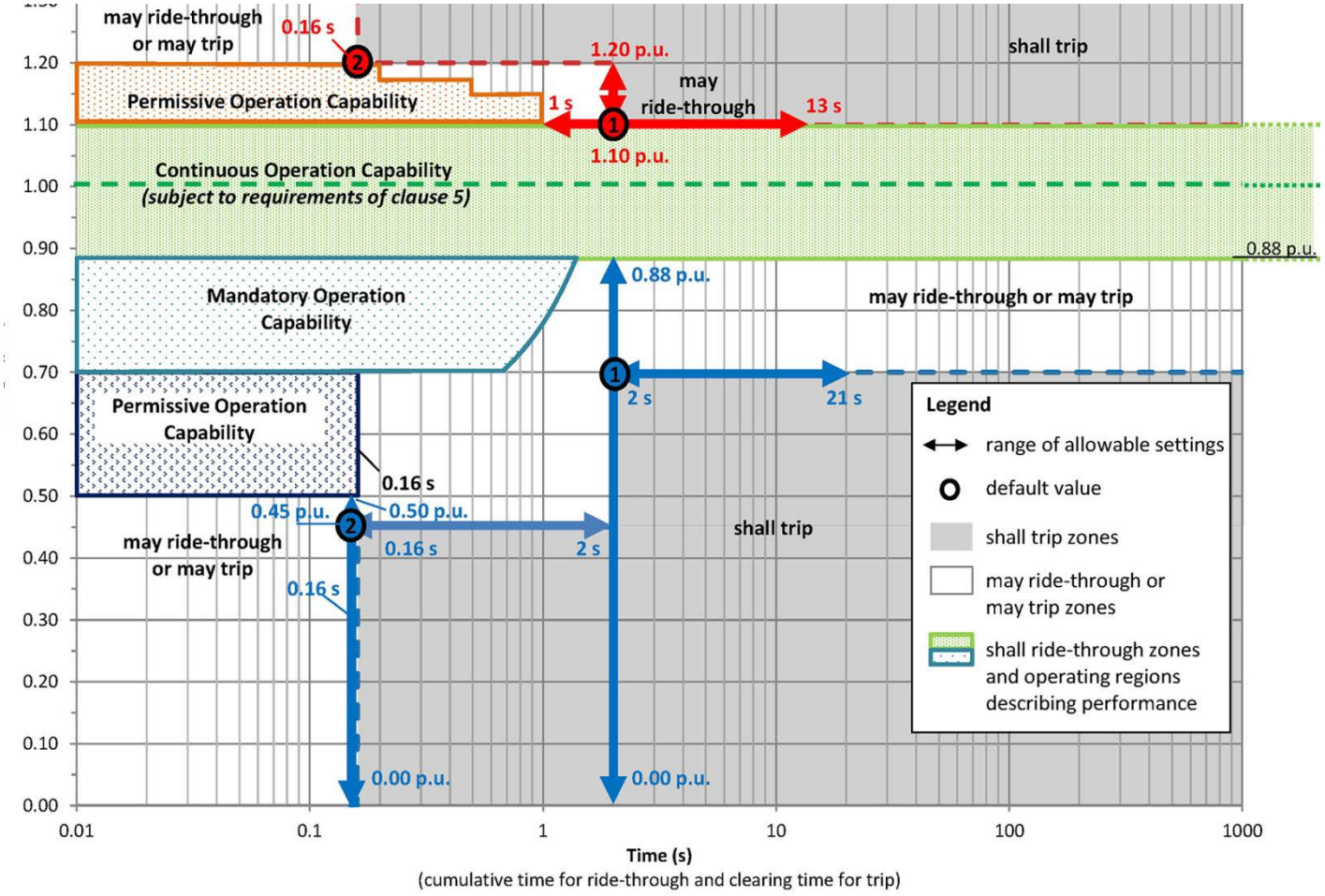
Objectives

- **Look in detail at some of the voltage and frequency control requirements as well as the momentary cessation and “shall trip” requirements set forth in IEEE Std 1547**
- **Do this for different performance categories**
- **Compare these with NERC/ Eastern Interconnection Guidelines**
- **Do this by breaking the requirements into individual pieces and present them graphically**

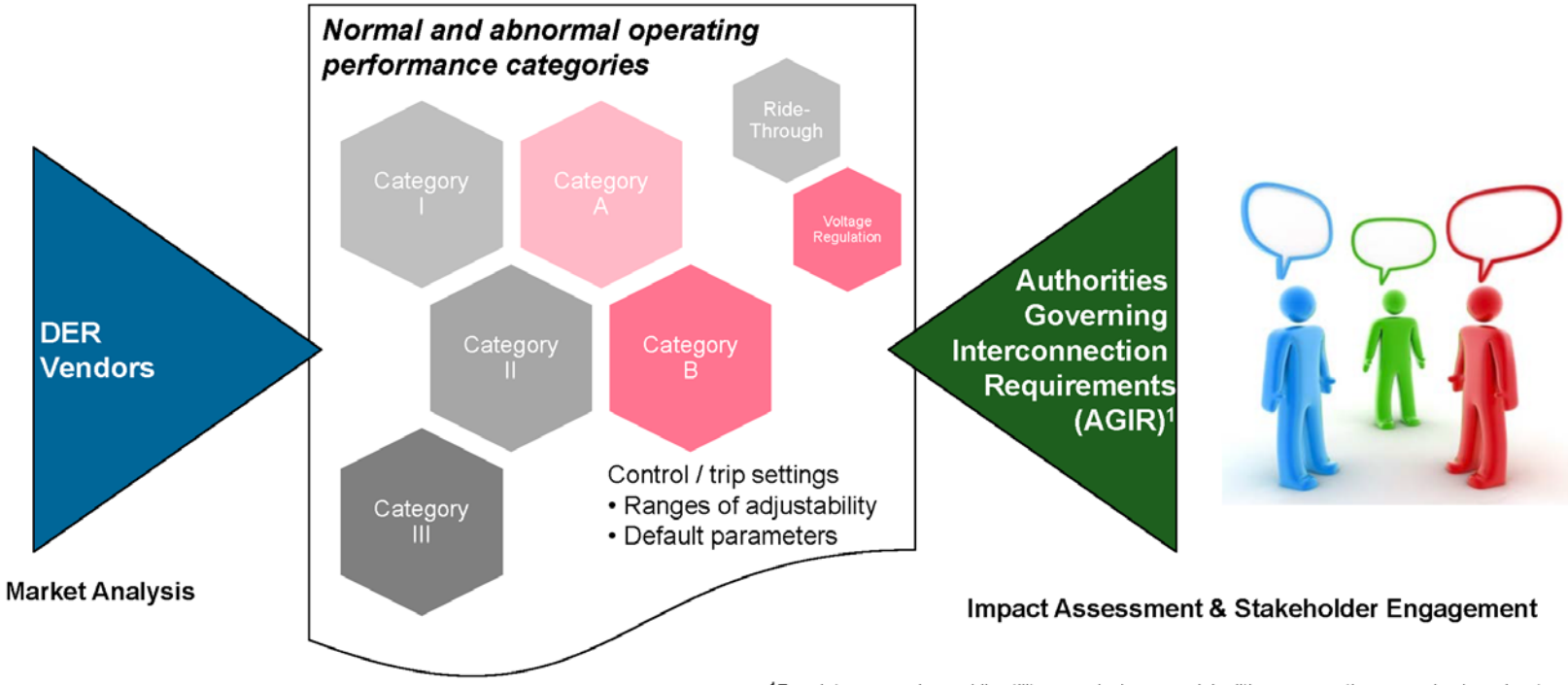
IEEE 1547 vs NERC PRC-024

- **1547**
  - Local Power Systems
  - Cessation – Safety – “Shall Trip”
  - Specifications variable depending on penetration
  - BPS Friendly with Larger Penetration
- **NERC**
  - BPS connected
  - Focus to maintain generating thru abnormal events
  - Cessation momentary for more extreme events
  - Avoid tripping

1547 Excerpt – Category I



1547 Performance Categories



[1]Regulatory agencies, public utility commissions, municipalities, cooperative governing boards, etc.

IEEE 1547 Categories of Operation

During Abnormal Voltage and/or Frequency Conditions

- **Categories I,II,III – Disturbance Ride Thru by Penetration and Impact on BPS:**
  - **Category I** – DER has little impact-German Std-met by all technologies
  - **Category II** – Increasing BPS Concern –Complies NERC PRC-024-2
  - **Category III** – BPS and DU stability needs-California Rule 21
- **Categories A,B – Voltage Regulation Performance:**
  - **Category A** – const p.f., Q/voltage, Const Q
  - **Category B** – Adds watt/voltage
  - Different set points/characteristics for each category

Who Decides Which Category?

- **AGIR**
  - **A**uthorities **G**overning **I**nterconnection **R**equirements
- **DER Impact Assessment**
  - State Regulators
  - EPS Operators
  - BPS Operators
- **Based on penetration level and impact**
- **Ultimately –** The interconnecting utility via interconnection agreement

Categories Based On:

- Future DER penetration levels
- DER power output variability
- Distribution system characteristics, e.g., fault-induced delayed voltage recovery (FIDVR) issues, feeder configuration and protection
- Bulk system characteristics, e.g., power reserves or future system inertia, loss of source concerns
- It could also consider non-technical issues such as DER use cases and the broader impacts of DER on the environment, emissions, and sustainability.

This analysis could be a starting point for a stakeholder process, initiated and managed by the AGIR, with the ultimate goal of assigning DER performance categories to specific DER (technology) types and application purposes (use cases).

IEEE 1547 Operating Modes

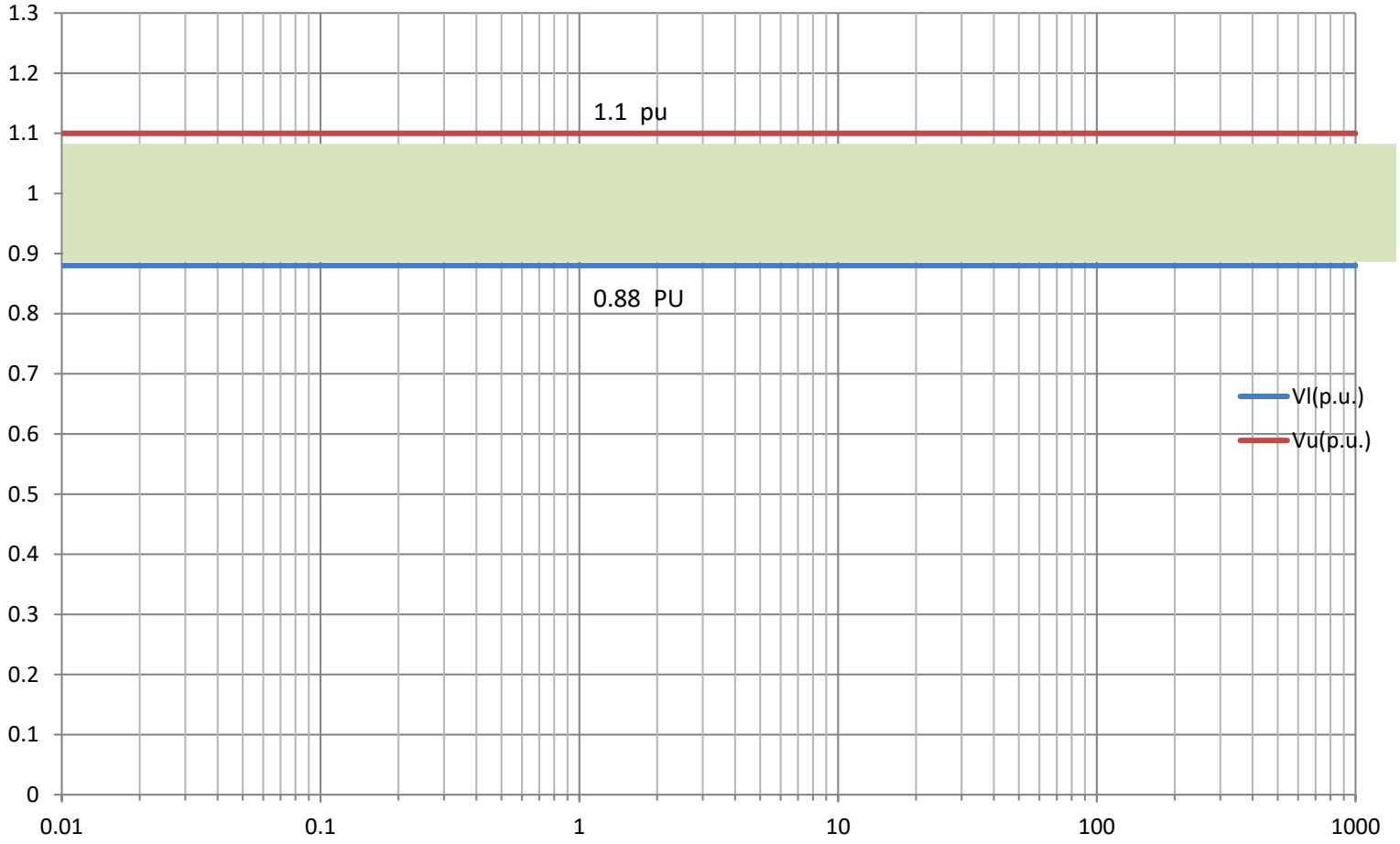
- **“Continuous”** – Normal voltage and frequency control
- **“Mandatory”** – Maintain voltage and frequency control for short term deviations of voltage and frequency from normal continuous operation
- **“Momentary Cessation”**-Unit ceases generation then recovers
- **“Permissive”** -Unit has choice of Mandatory Operation **or** Momentary Cessation
- **“Shall Trip”** -Unit forced to trip and not return momentarily

VOLTAGE

Let’s Break it down

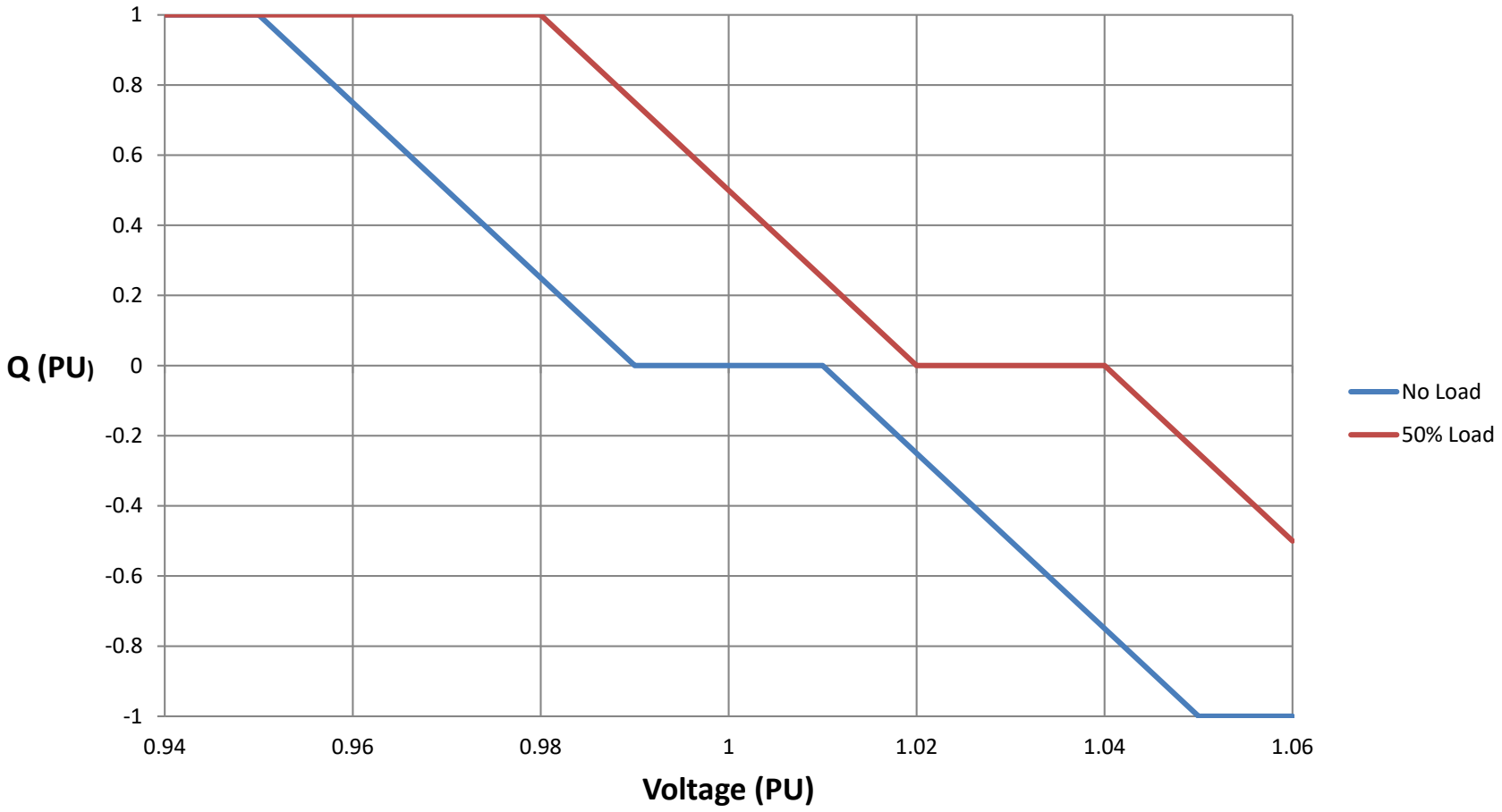
Continuous Operation

Categories I,II and III



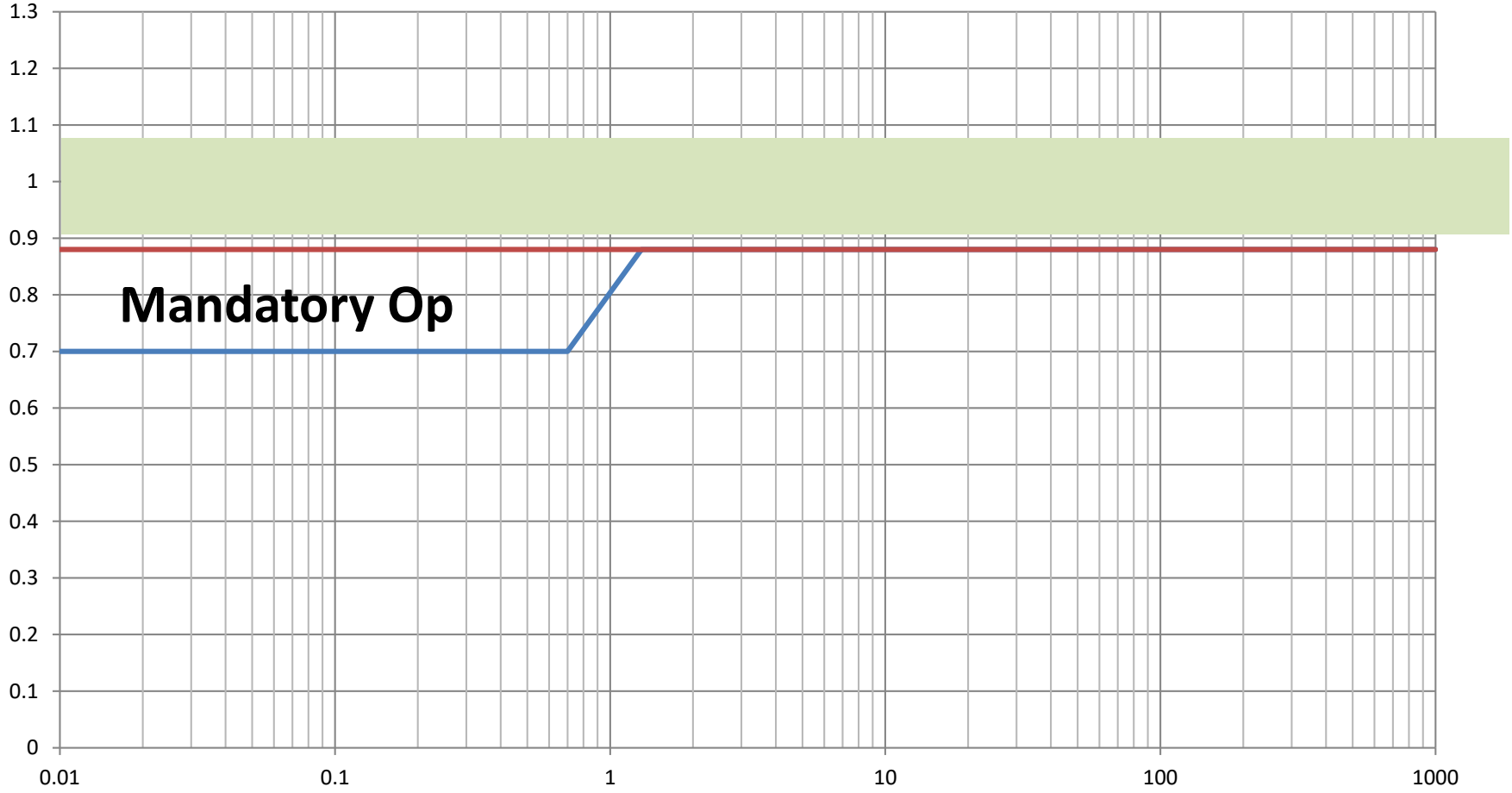
Typical Volt/VAR Control

(One Mode of Operation)



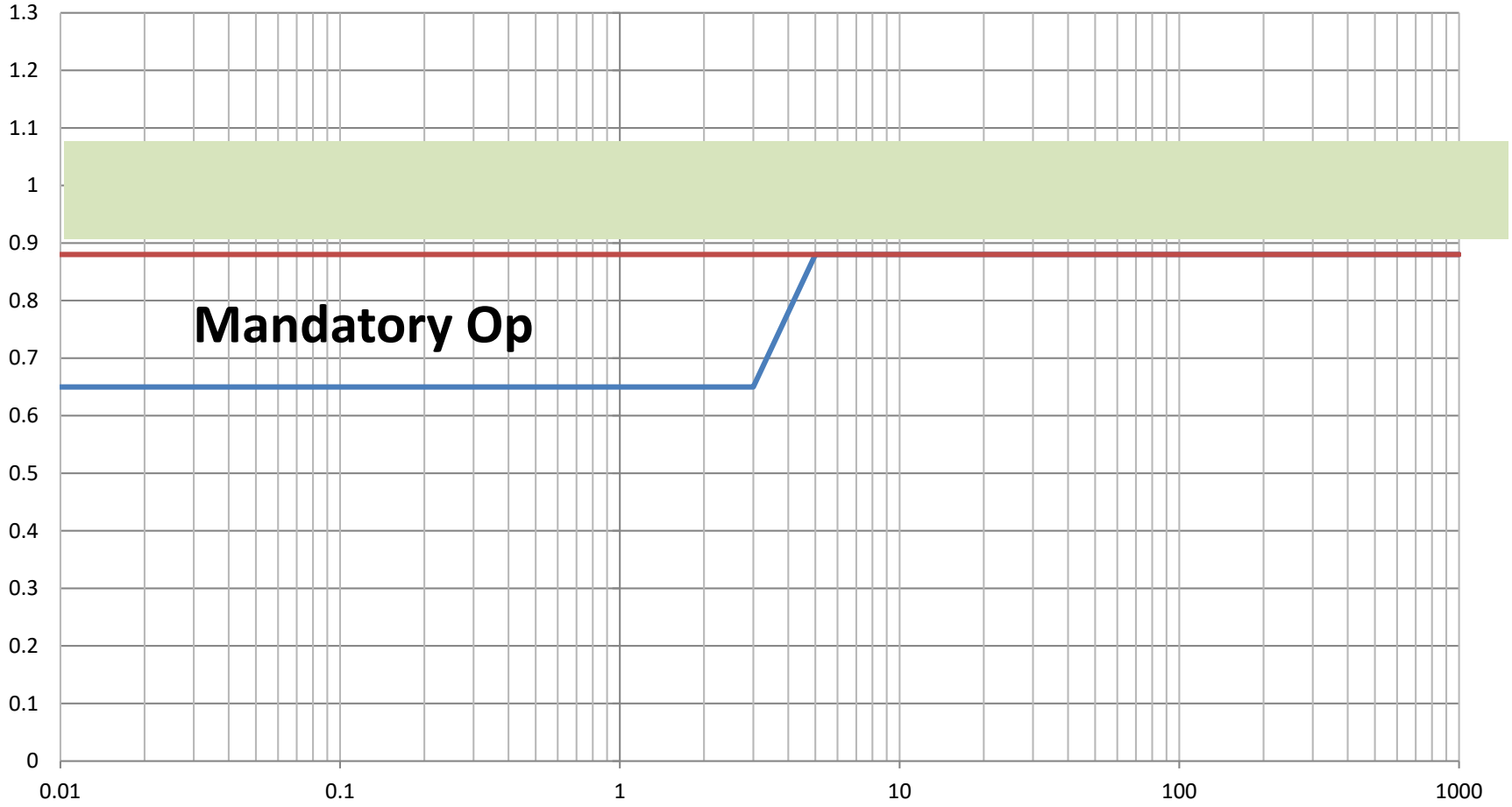
Mandatory Operation

Category I



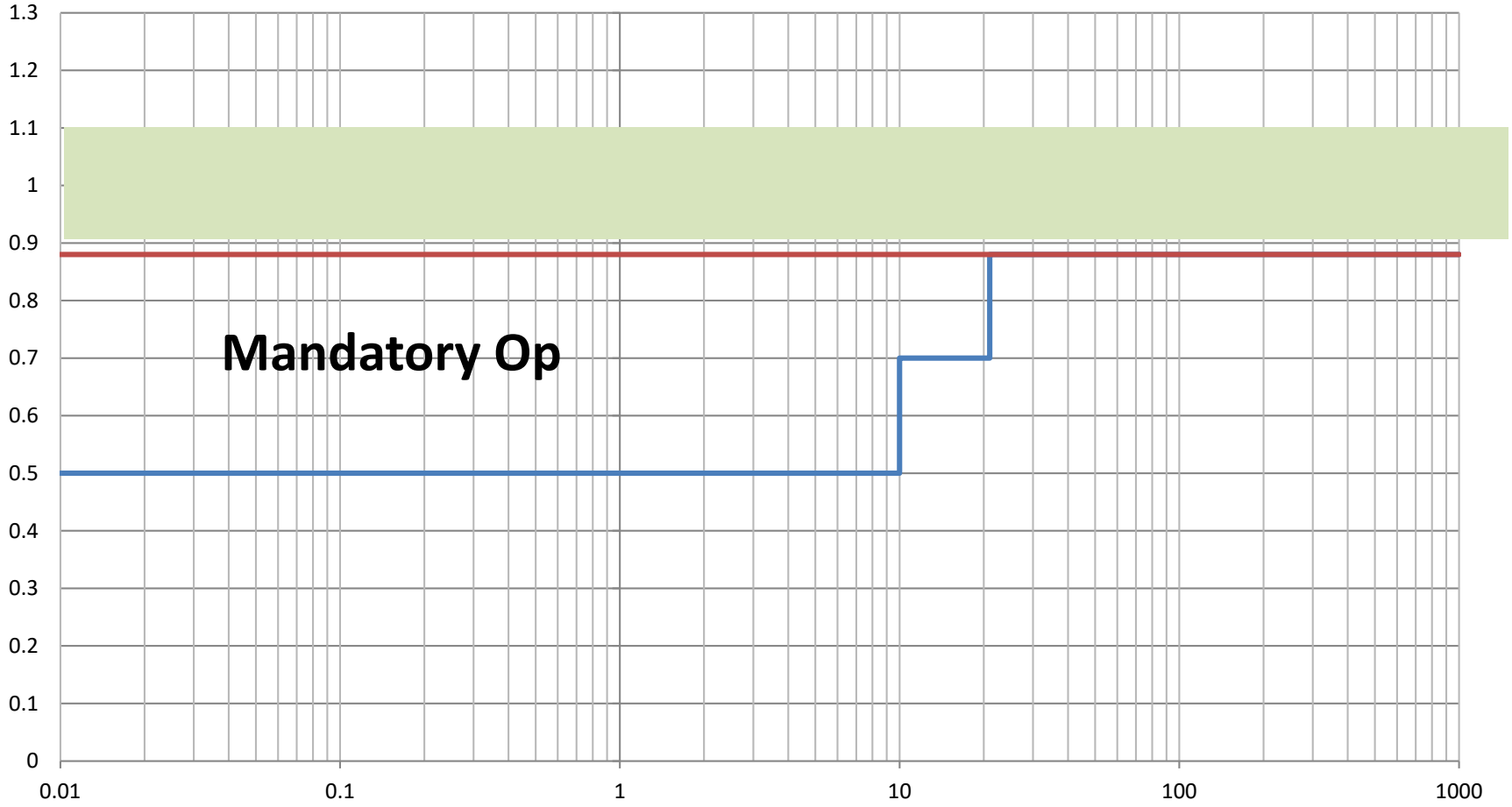
Mandatory Operation

Category II



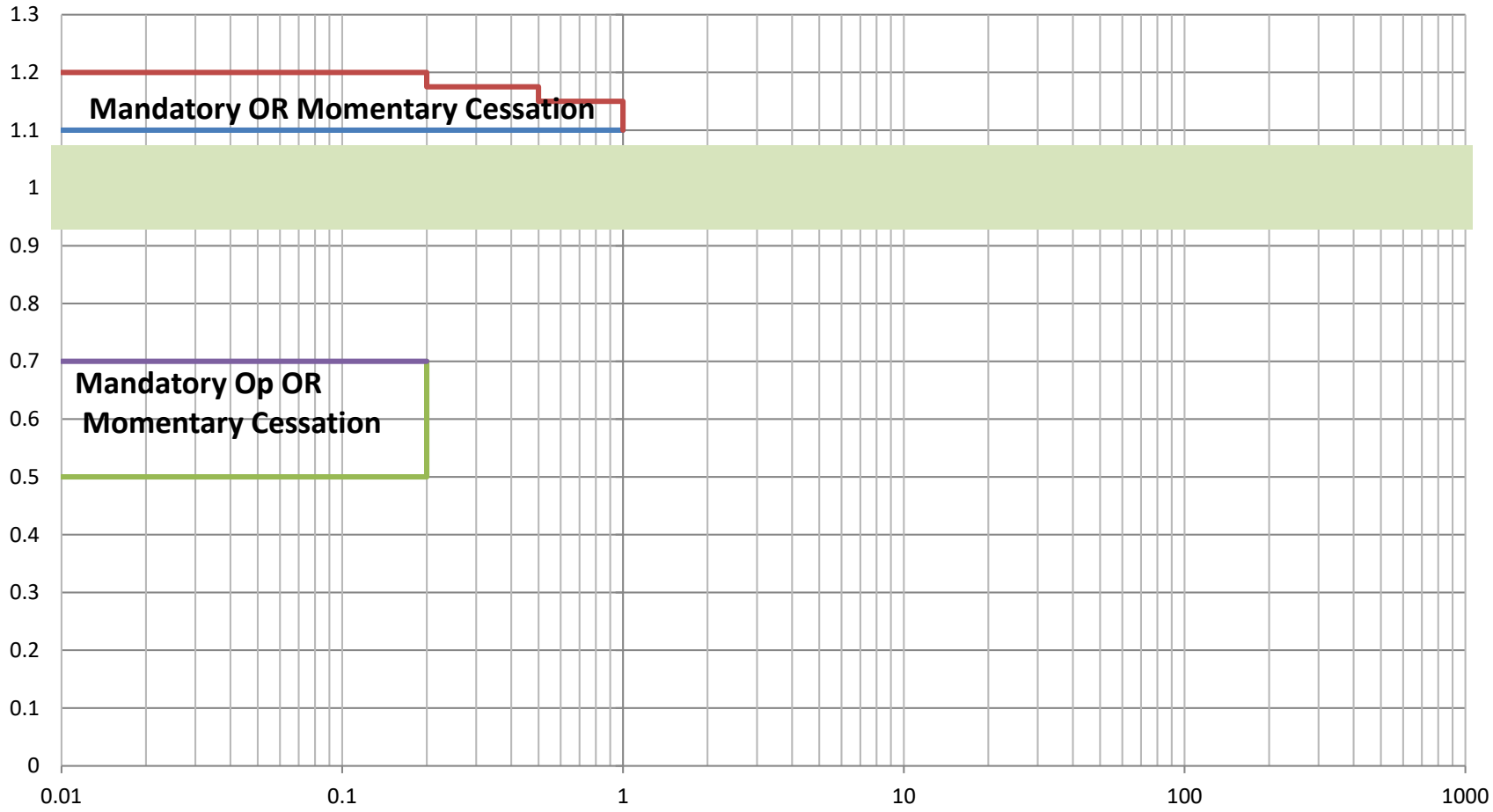
Mandatory Operation

Category III



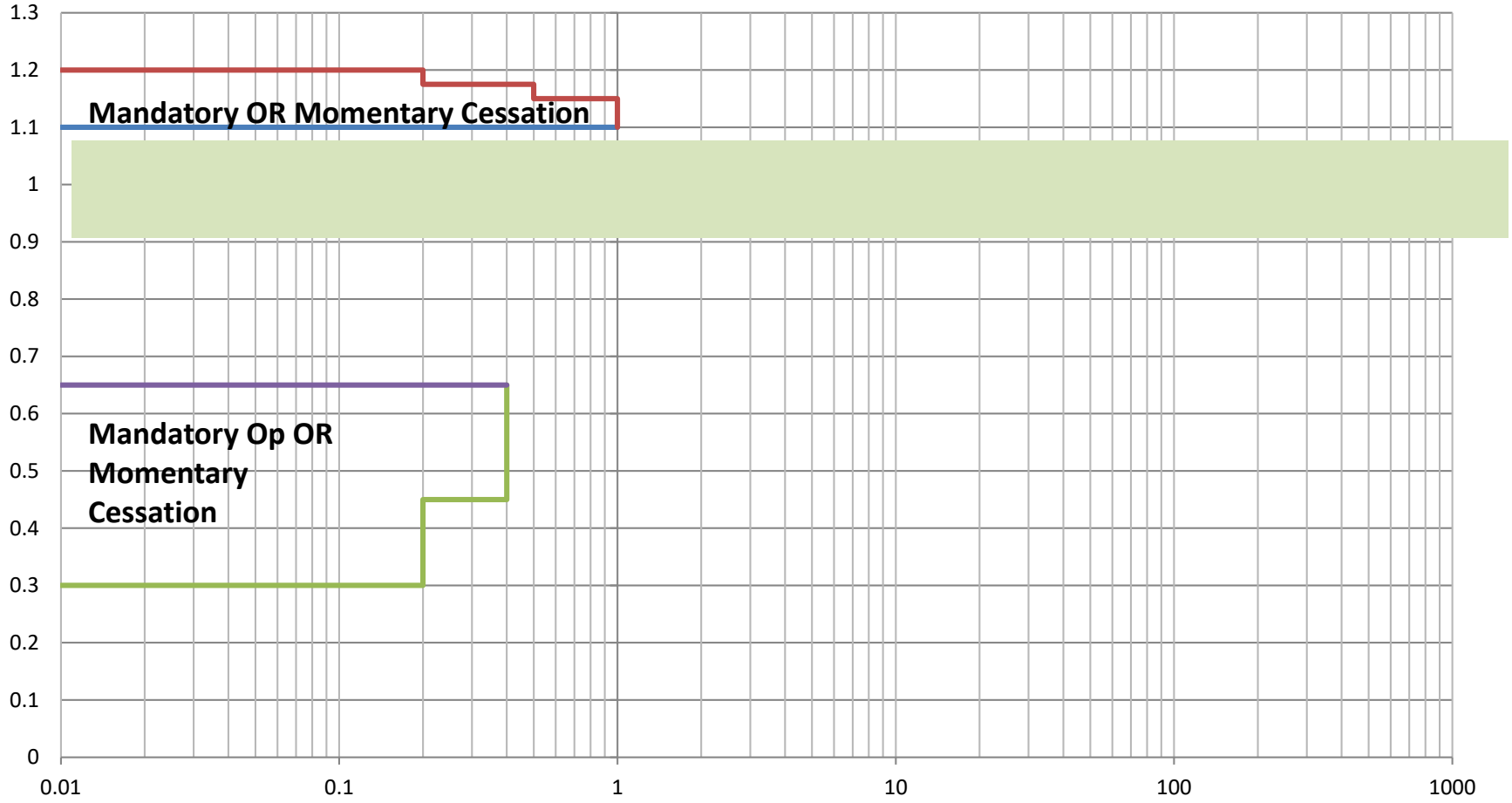
Permissive Operation

Category I



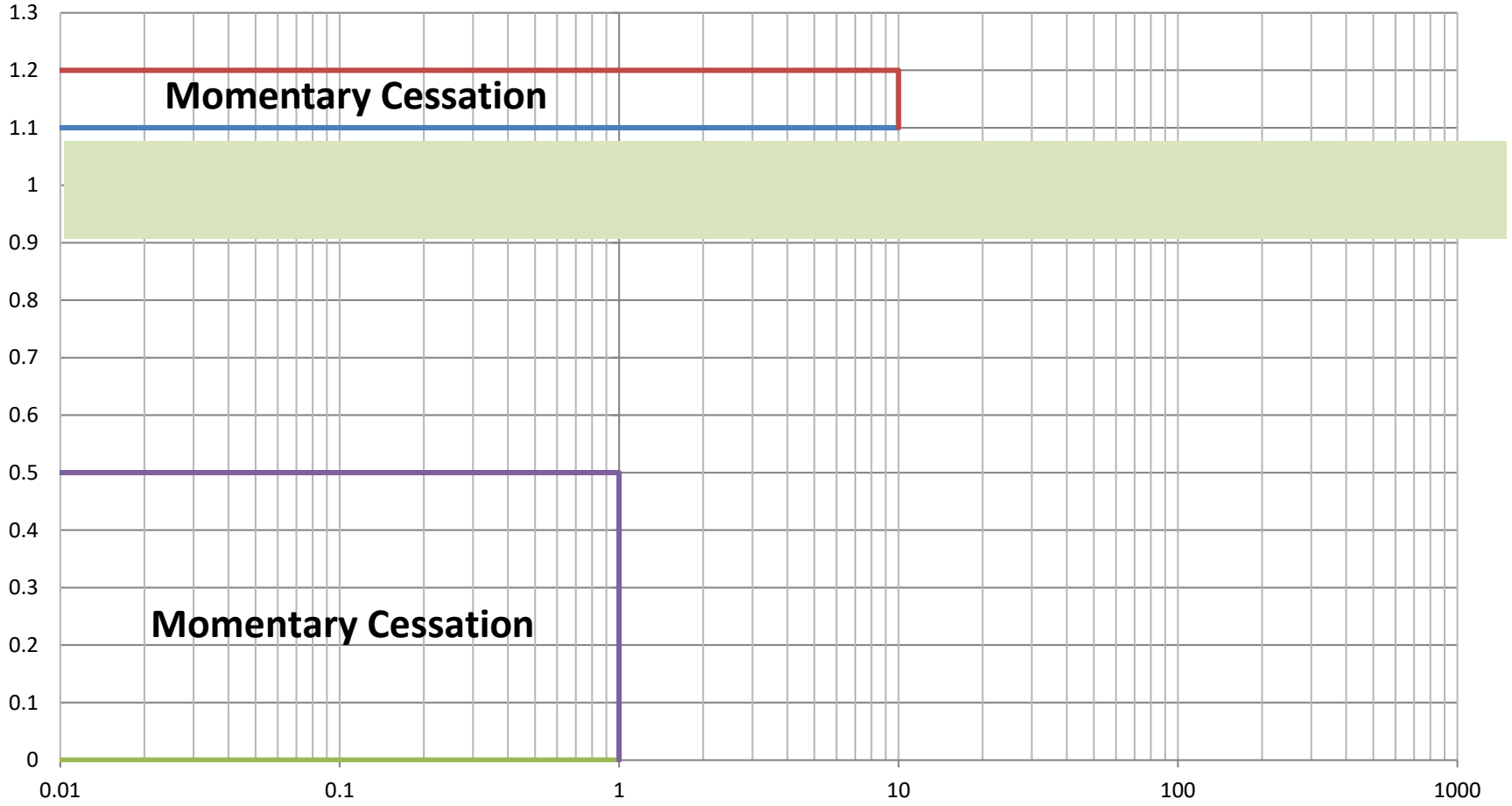
Permissive Operation

Category II



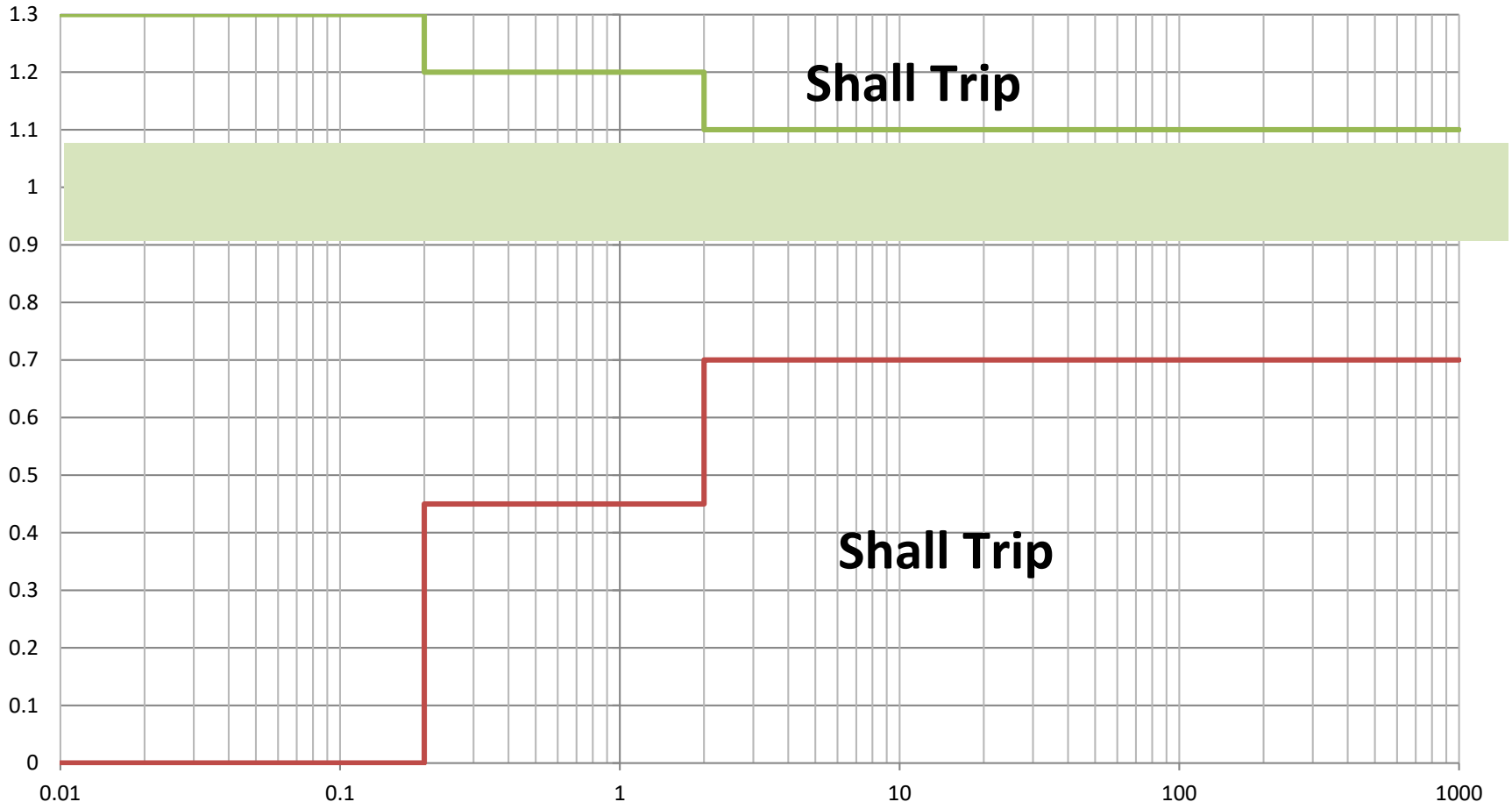
Momentary Cessation

Category III



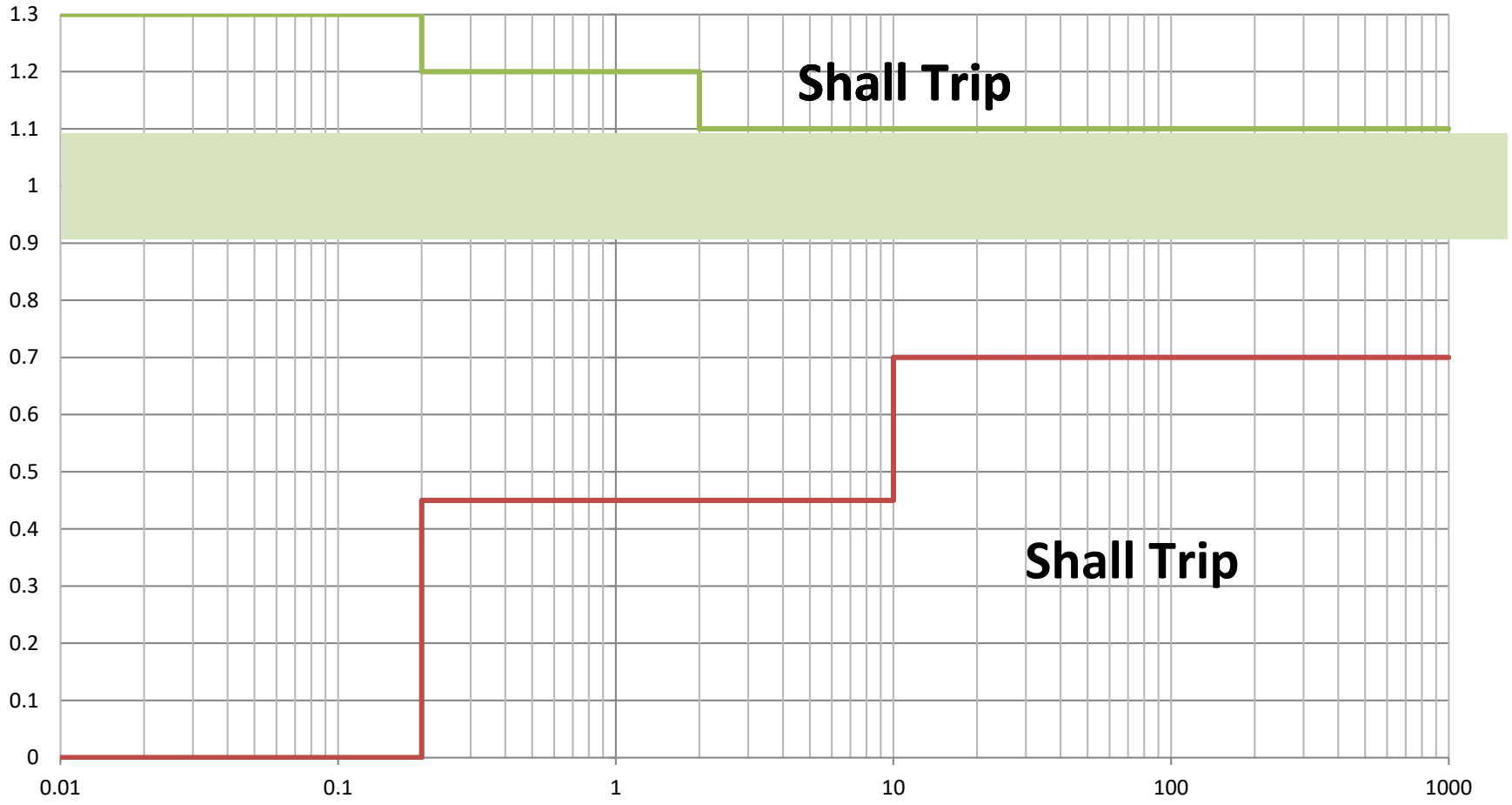
Shall Trip

Category I



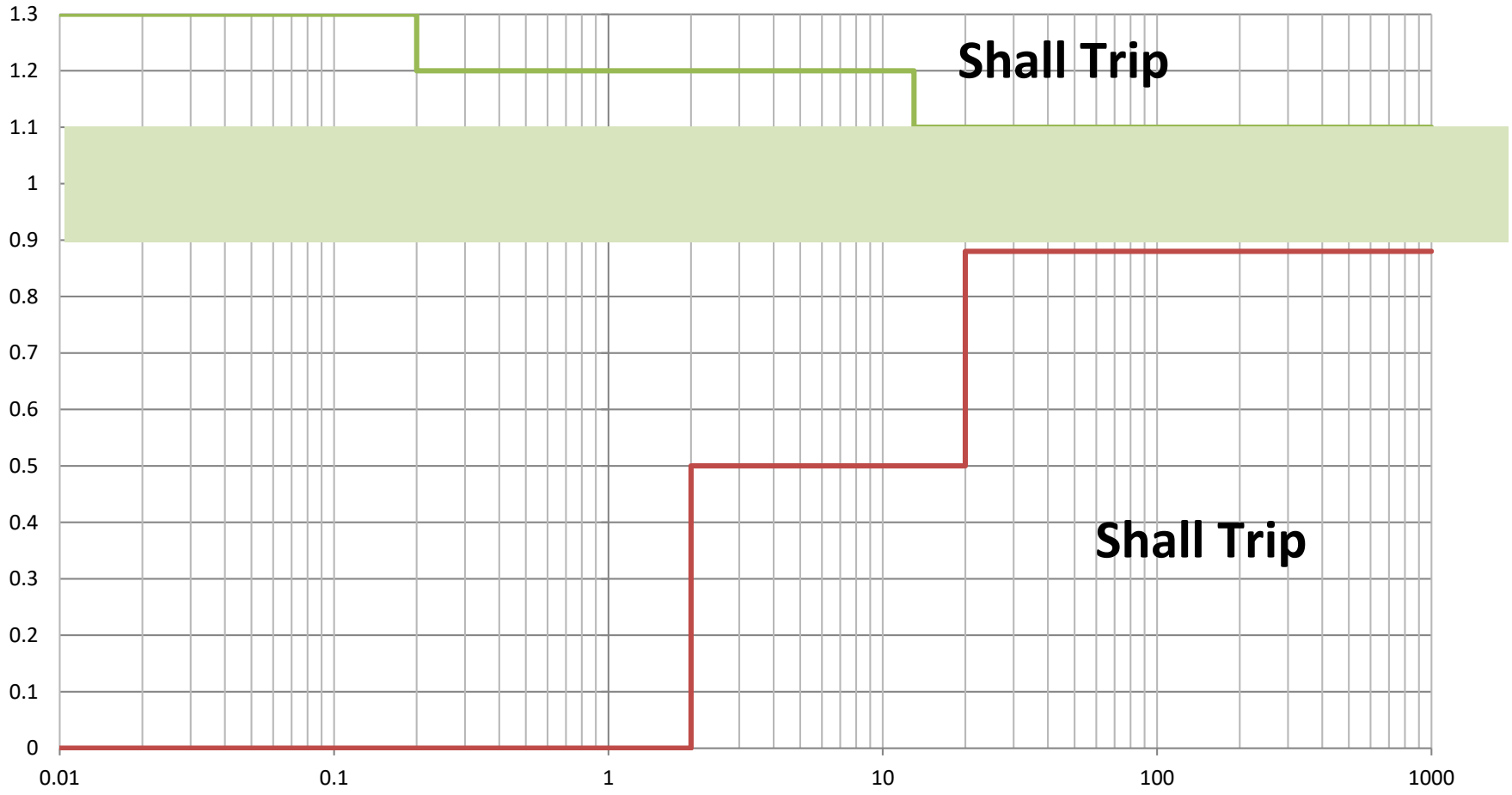
Shall Trip

Category II



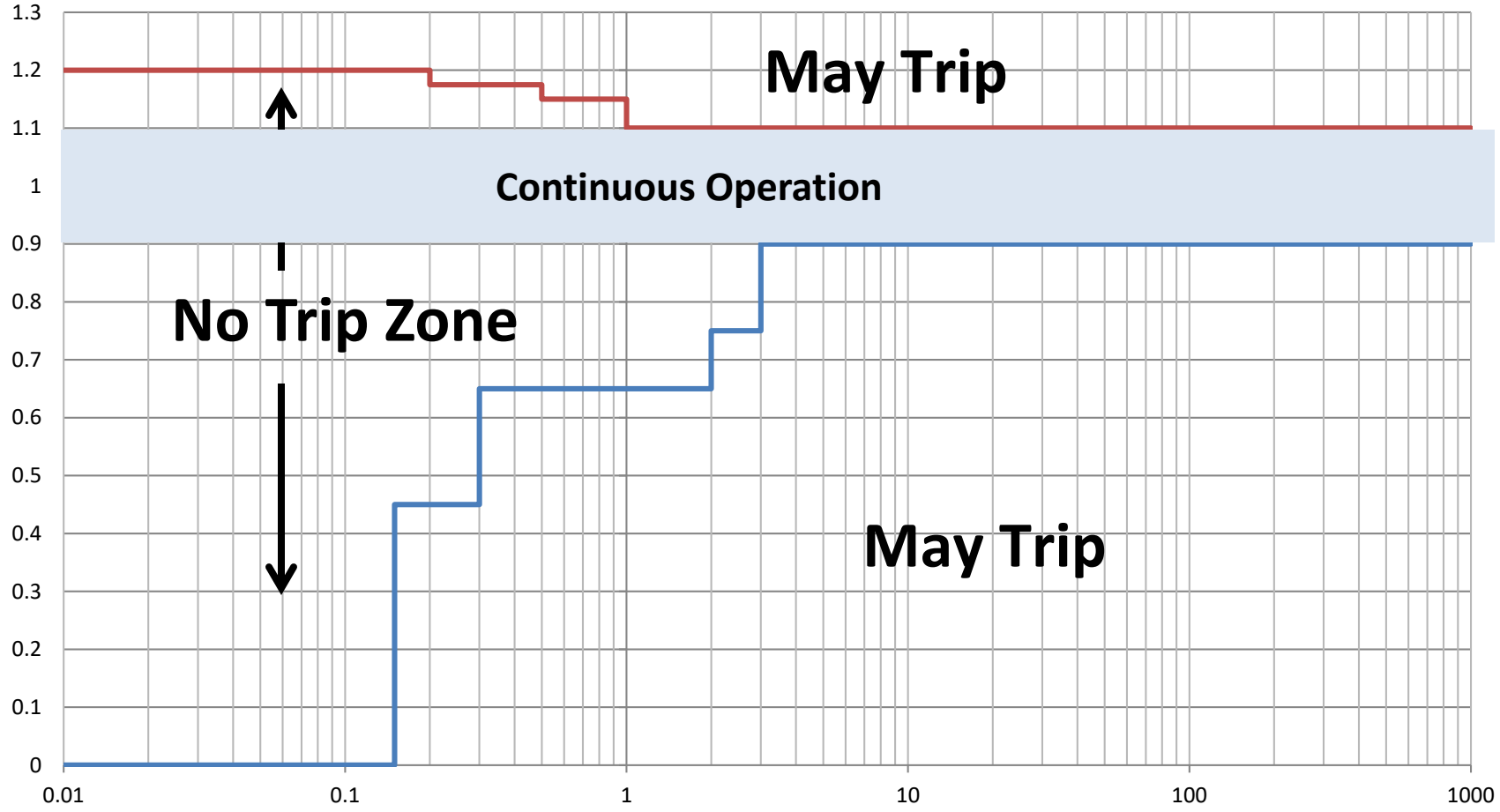
Shall Trip

Category III



NERC

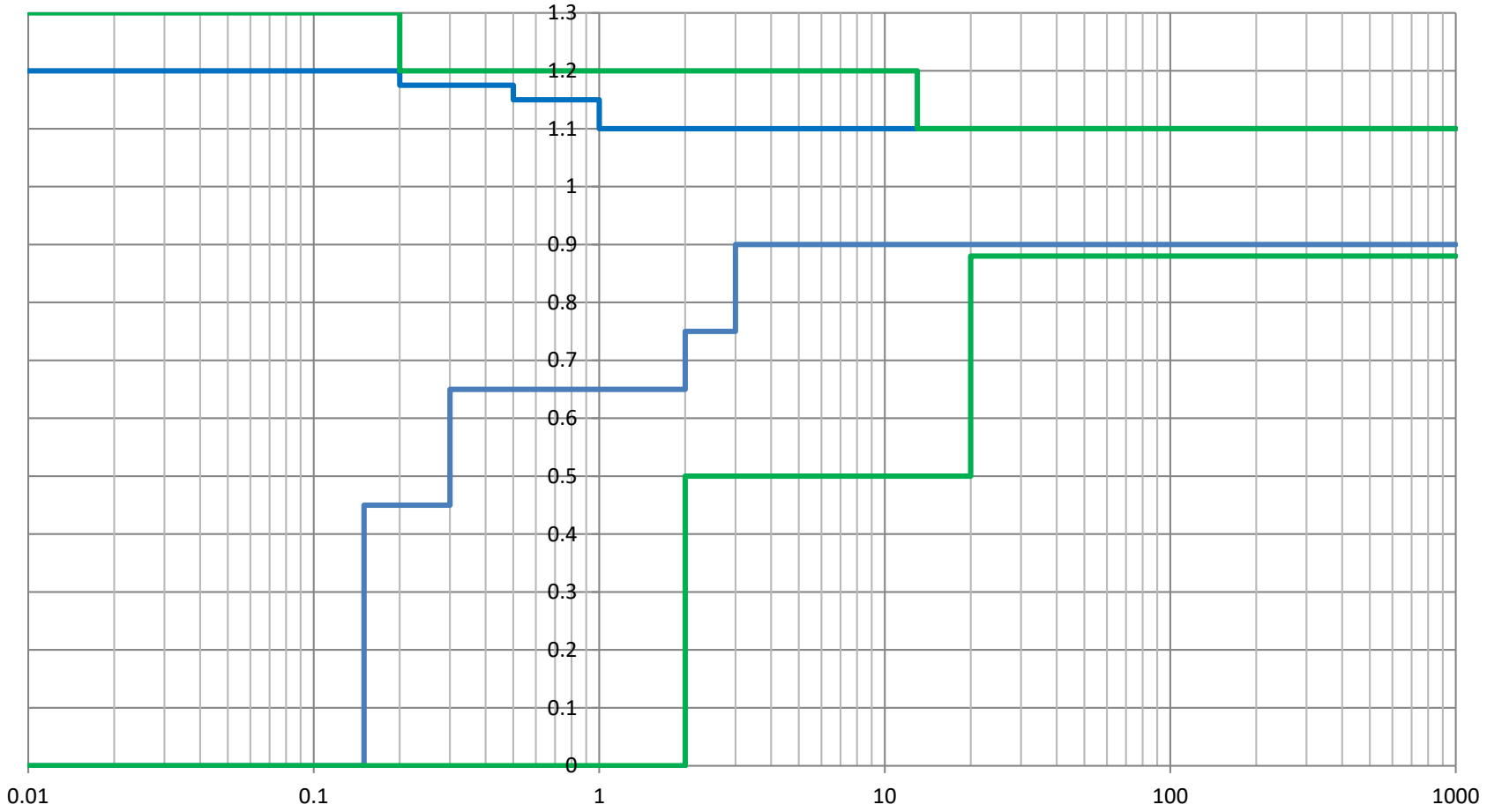
Voltage Ride Through per PRC-024



NERC vs 1547 Cat III Voltage

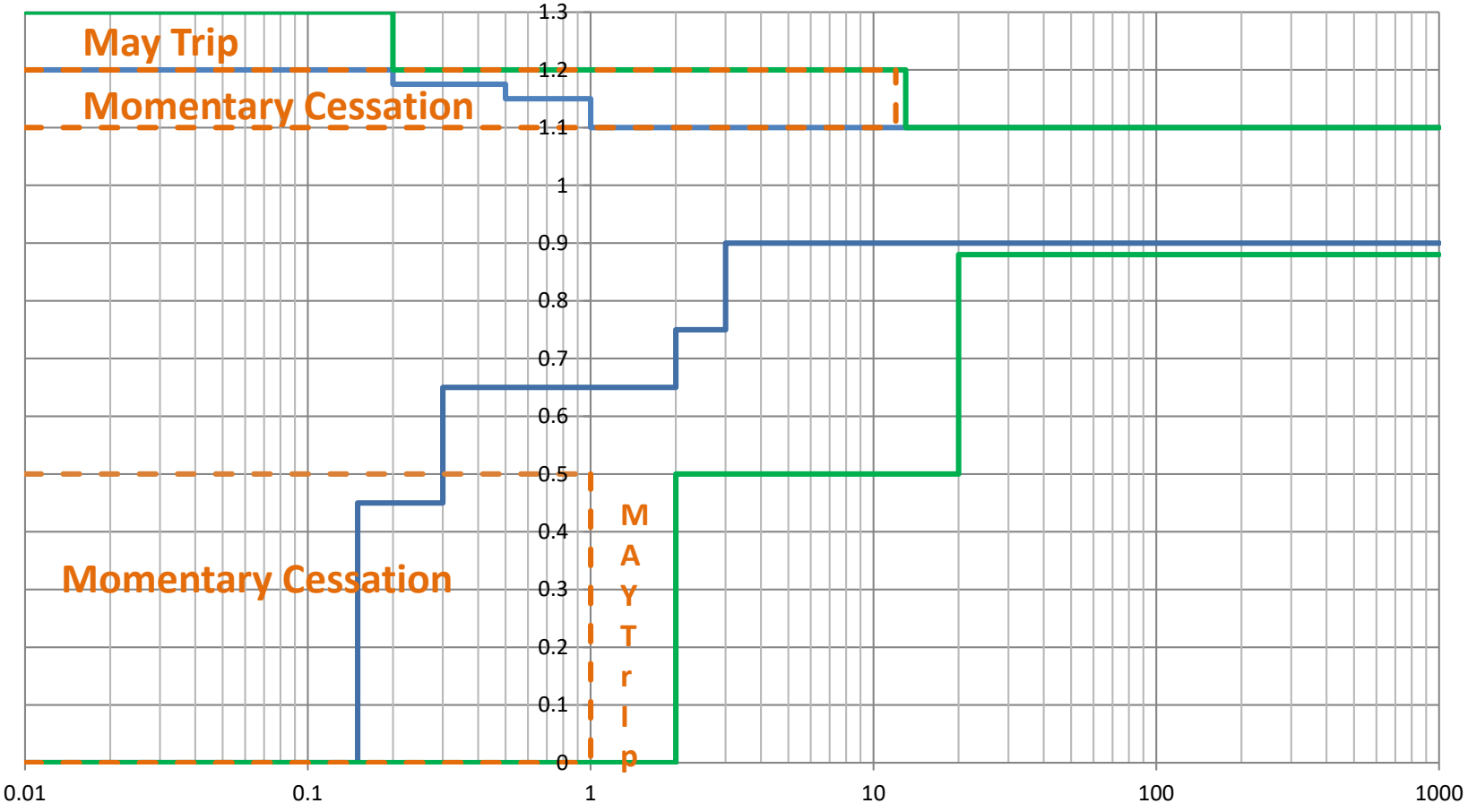
Appears to be More Stringent than NERC

But what about Momentary Cessation and Ride Thru?

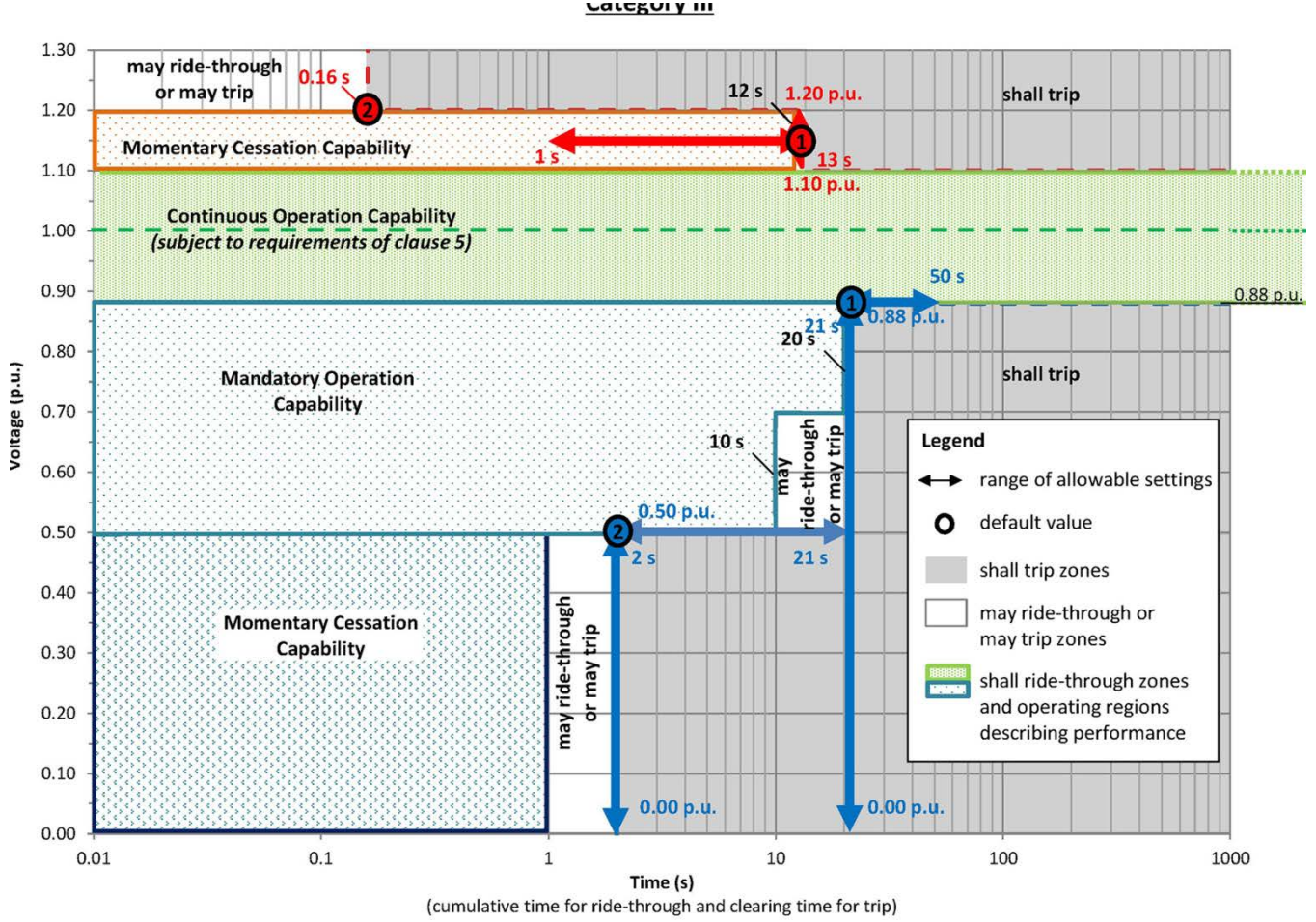


But 1547 Cat III Allows Momentary Cessation Plus May Trip

So it is less stringent than NERC Ride thru



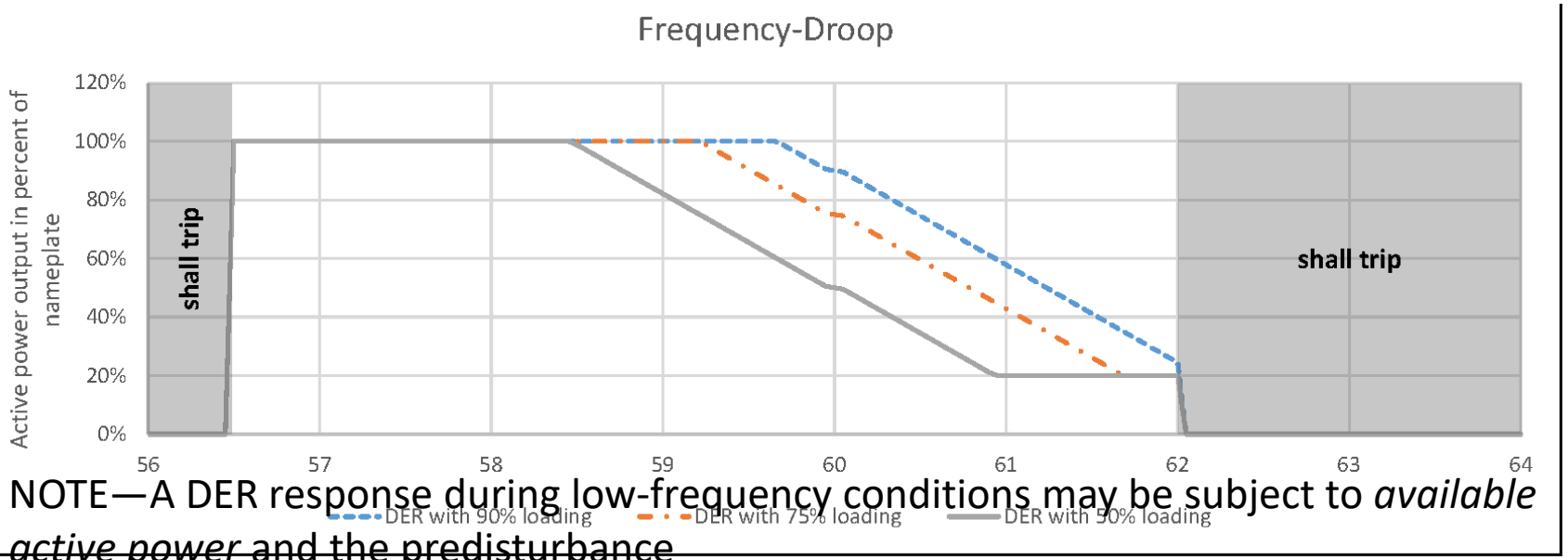
1547 Category III



FREQUENCY

Frequency Control Example

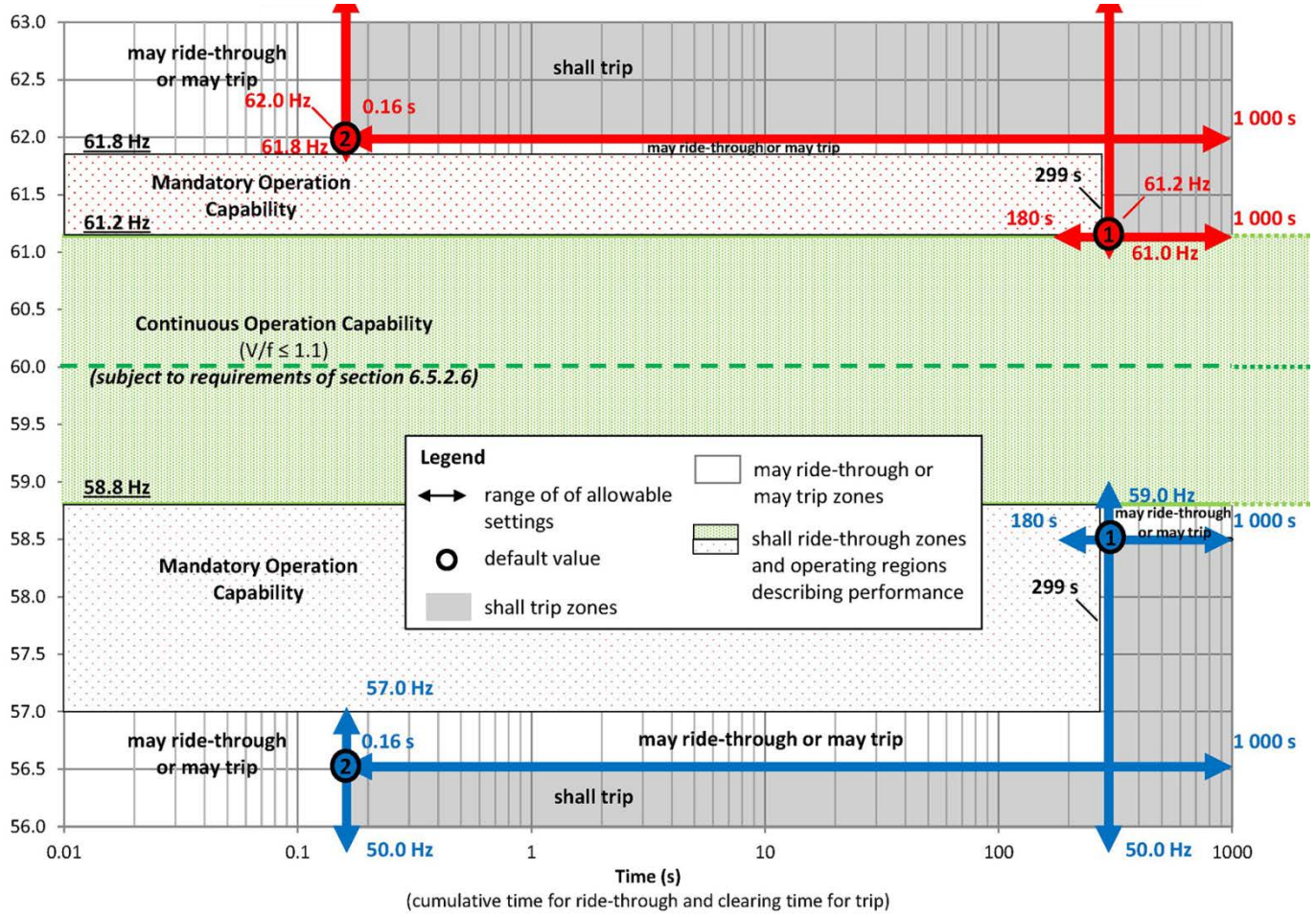
Figure H.11—Example of a three frequency-droop function curves with a 5% droop, 36 mHz deadband, and 20% minimum active power output for DER operating at different pre-disturbance levels of nameplate rating (50%, 75%, and 90%)



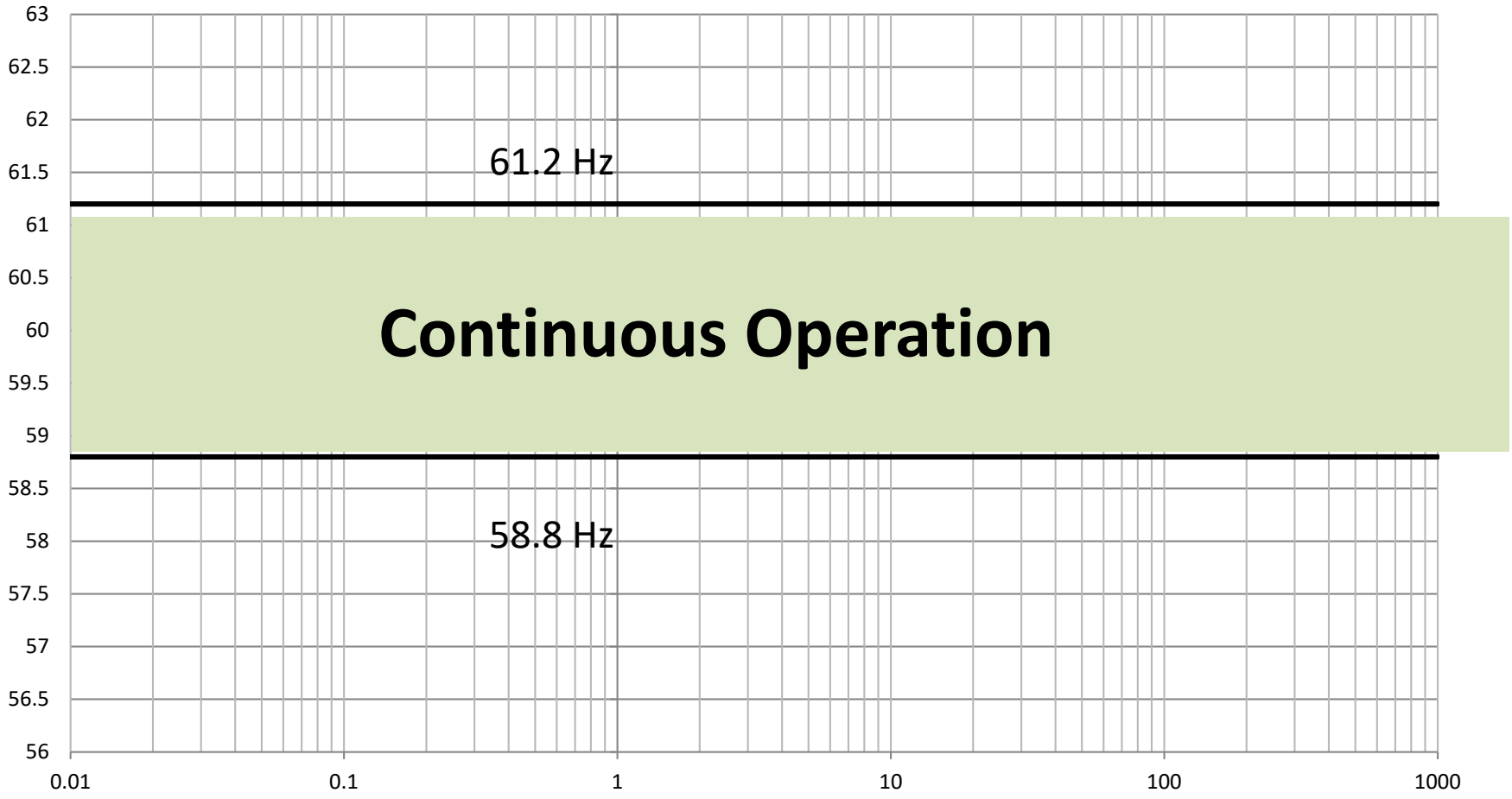
NOTE—A DER response during low-frequency conditions may be subject to *available active power* and the predisturbance dispatch level.

1547 Frequency Response Spec

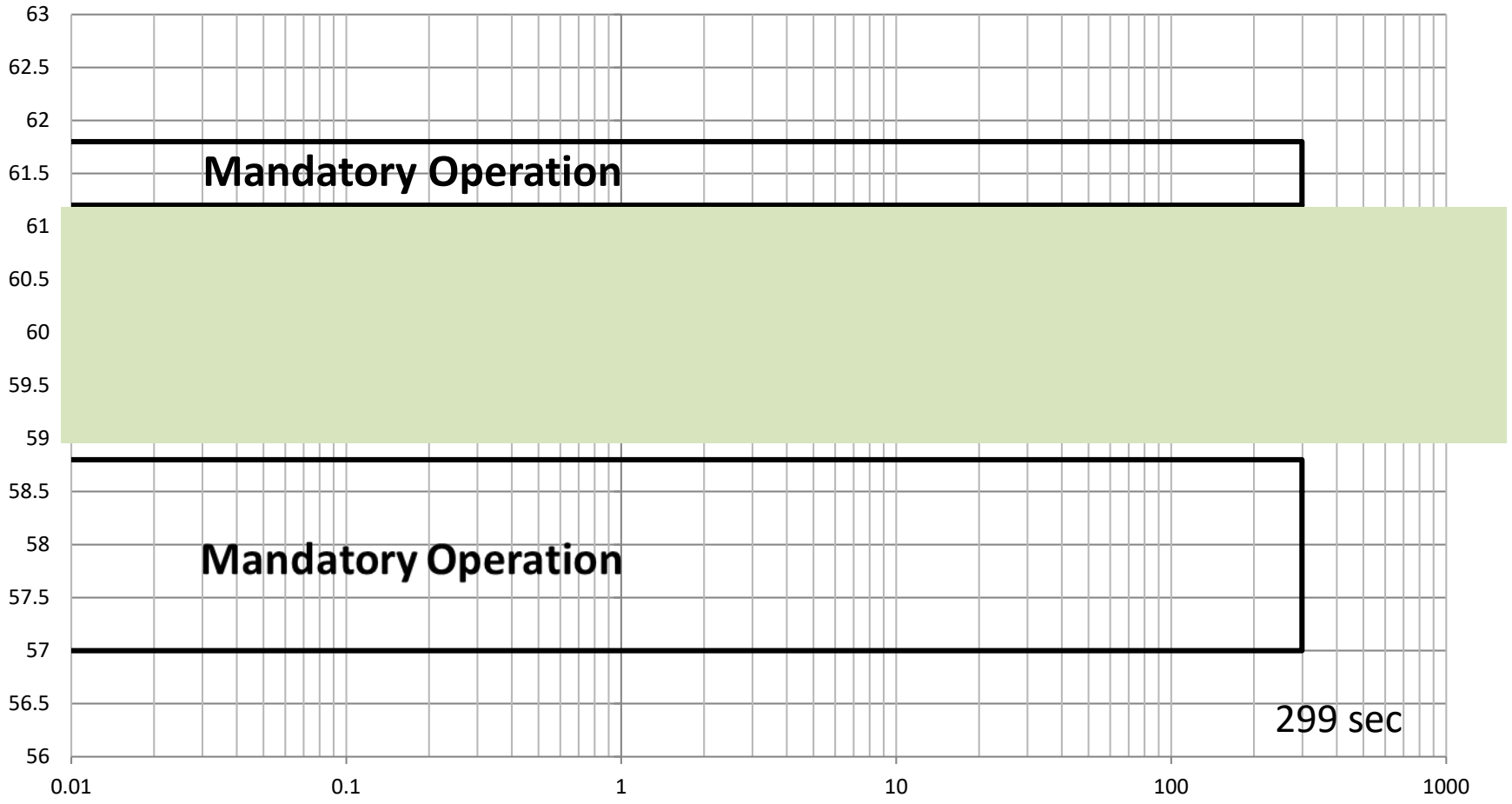
Categories I,II and III



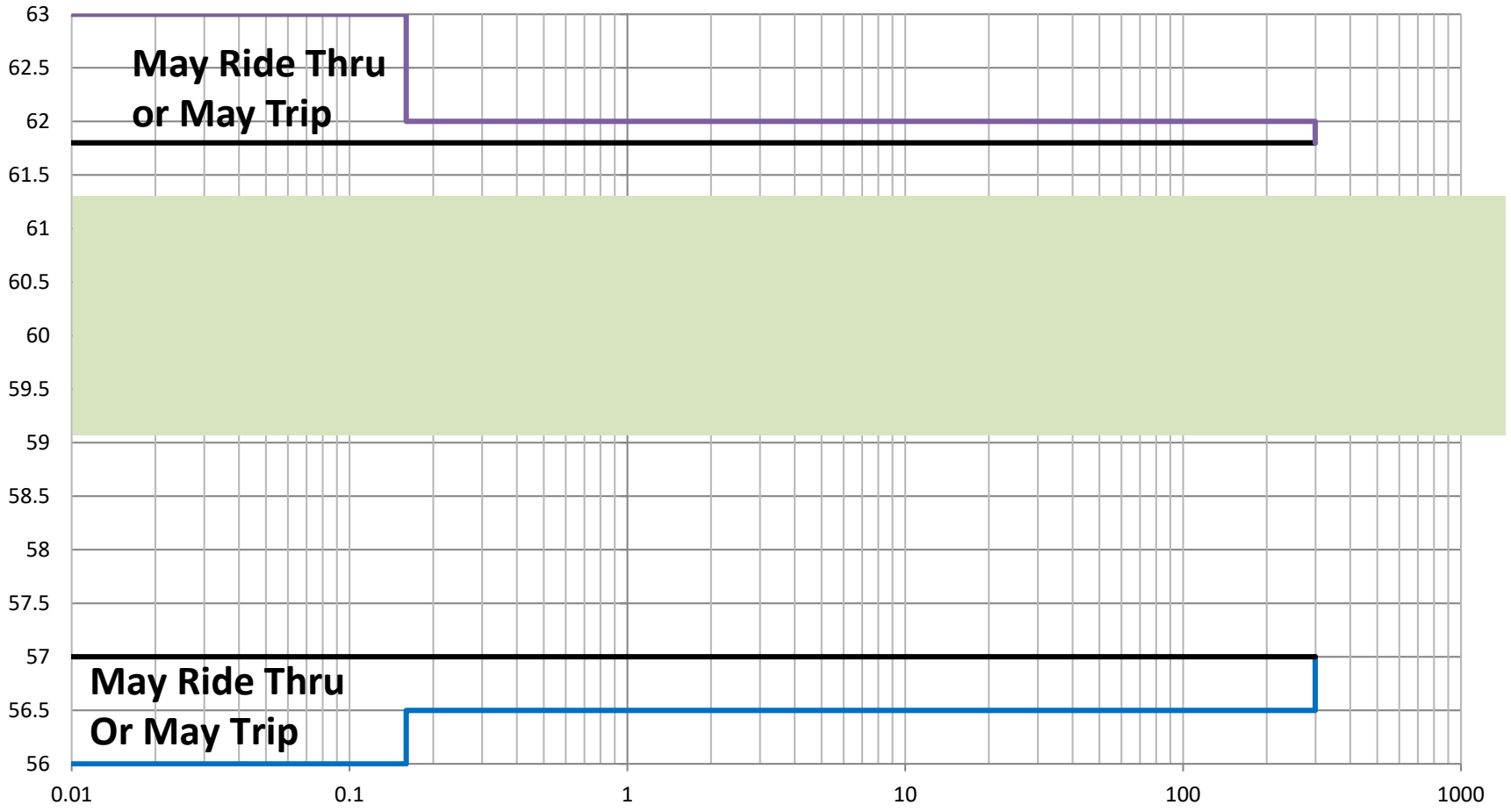
1547 Category I,II and III



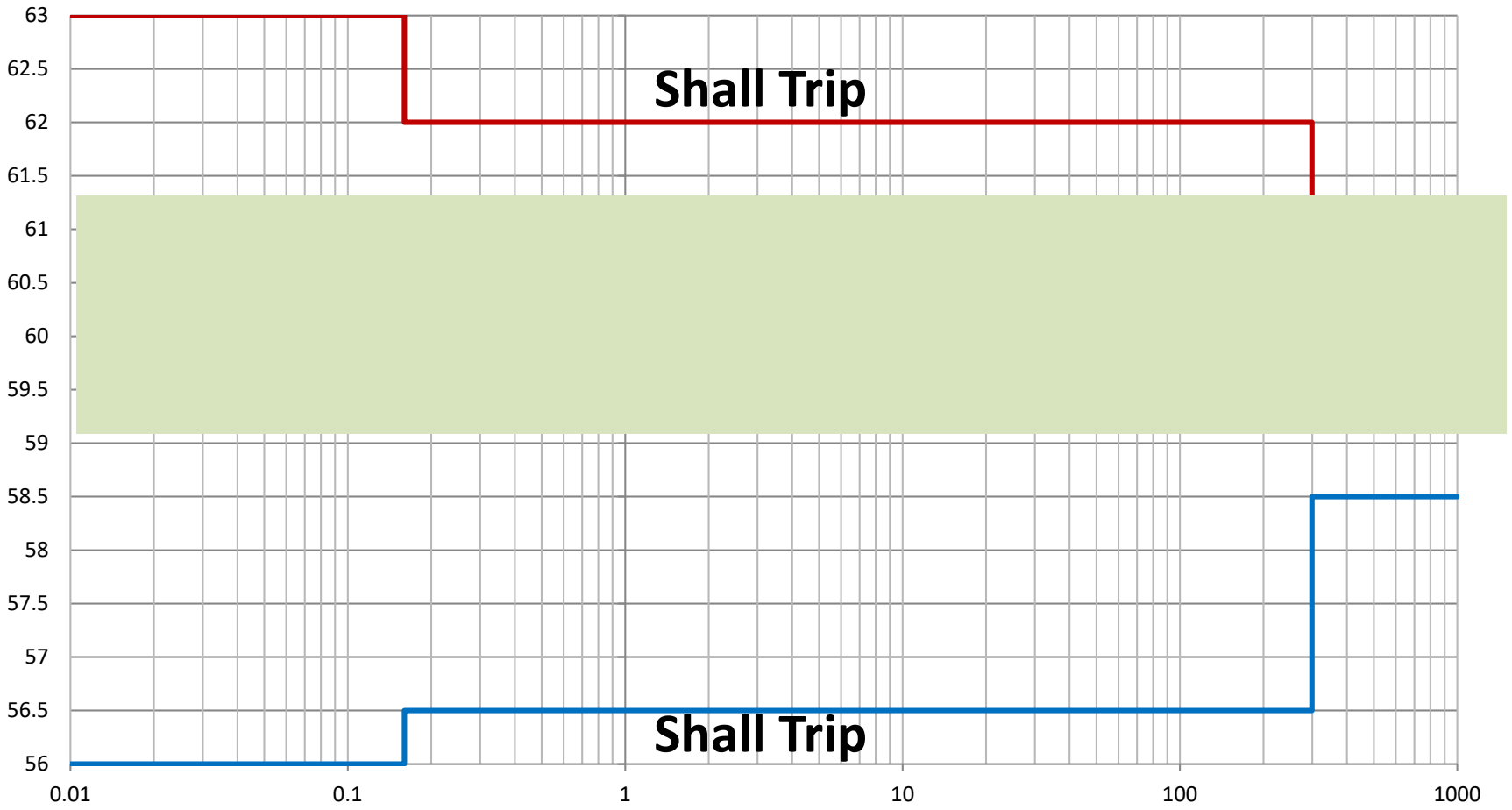
1547 Mandatory Operation



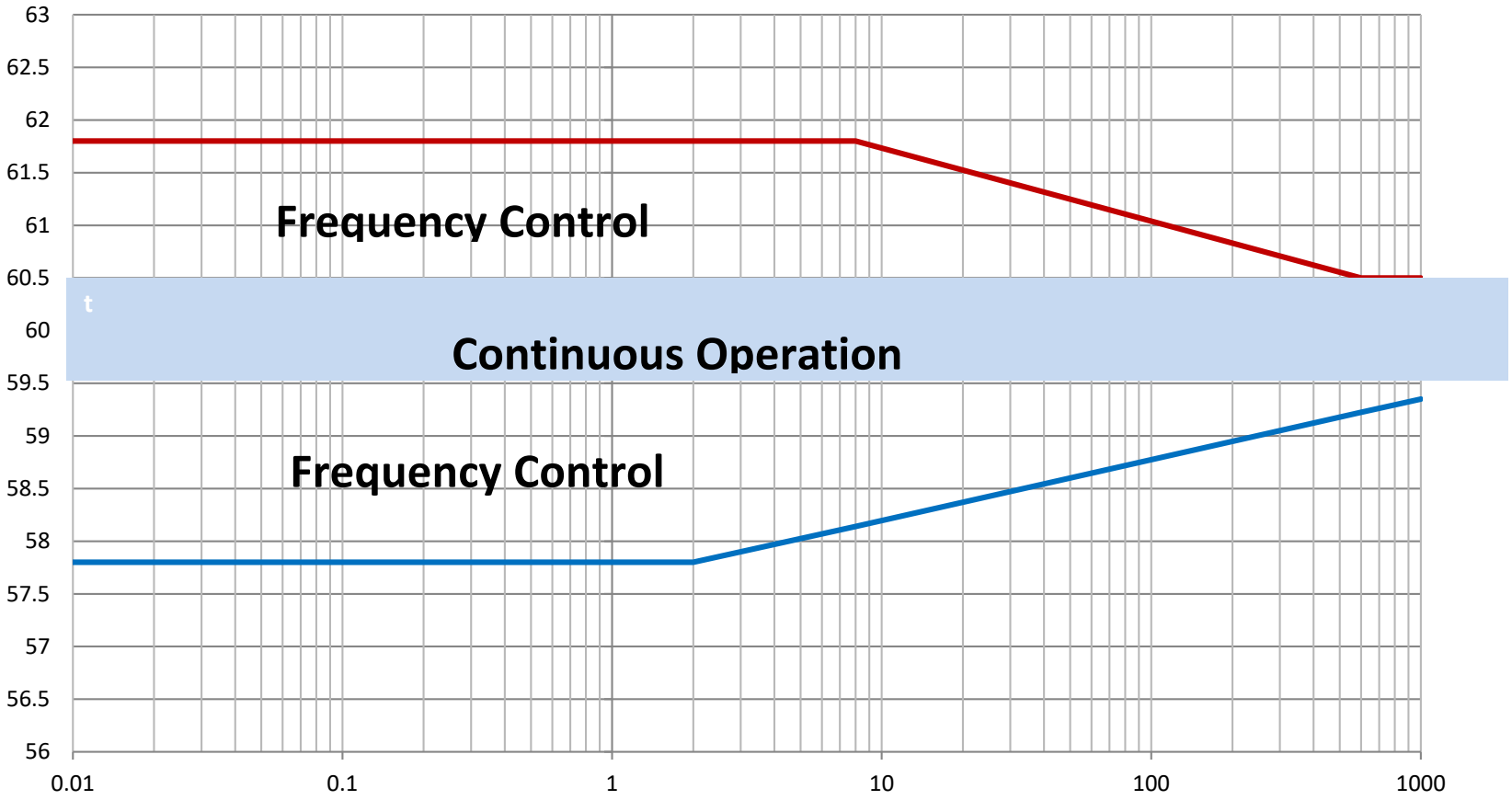
1547 May Ride Thru or May Trip



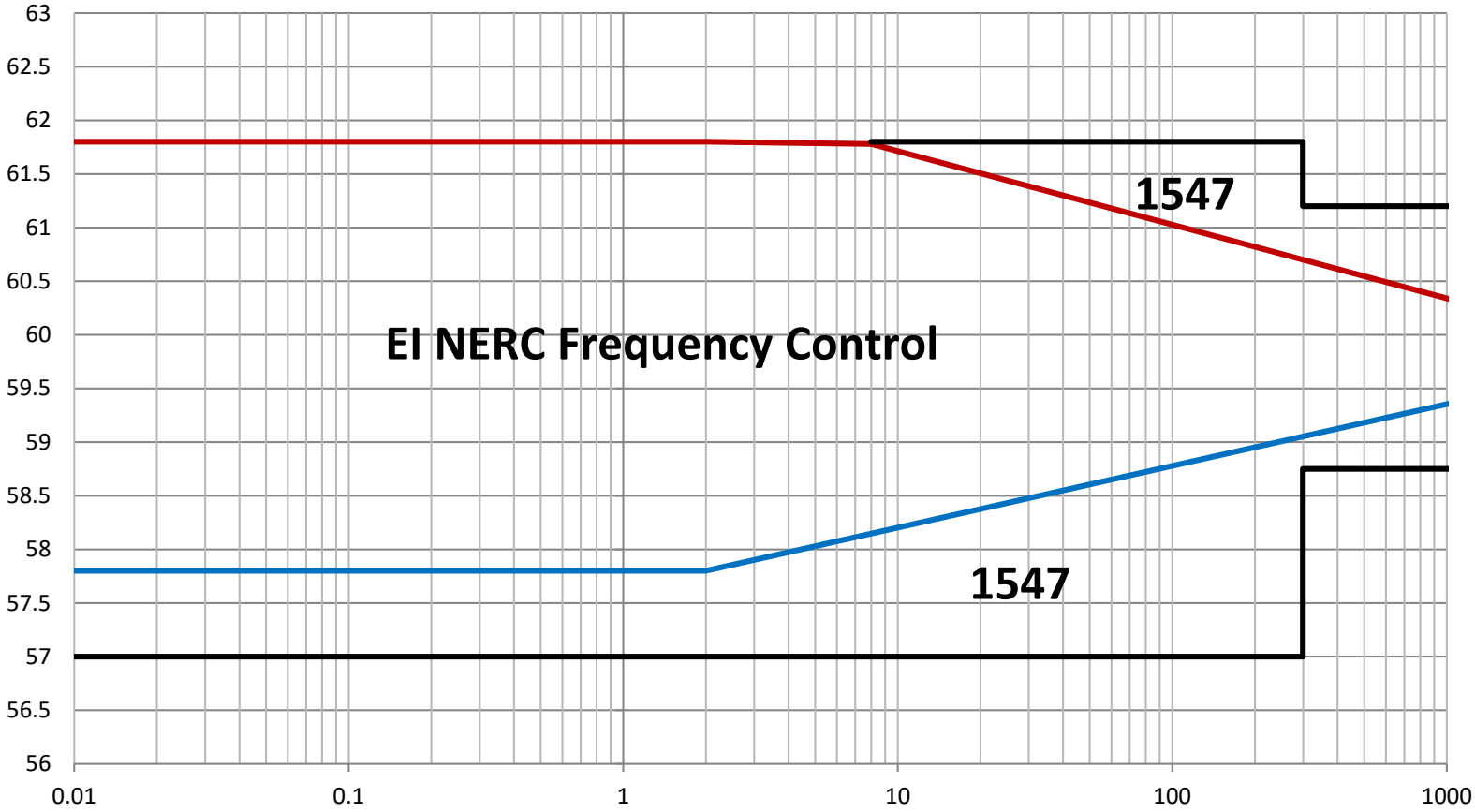
1547 Shall Trip



NERC (Eastern Interconnection)



Compare EI to 1547



Summary

- IEEE 1547 requirements variable depending on amount of penetration and impact
- Relate to local electric systems with an eye toward bulk power system impact
- With regard to voltage performance, 1547 Category III appears more stringent than NERC, but momentary cessation permissible within 1547 whereas NERC working toward minimizing momentary cessation operation for BPS connected facilities
- With regard to frequency performance, 1547 (all categories) appear to be more stringent than NERC
- Ultimately, for non BPS facilities, the AGIR (Agency Governing Interconnection Requirements) determines the performance requirements using IEEE 1547 as a guide

References

- **IEEE 1547 STD - 2018**

NEW YORK STATE OF OPPORTUNITY. Department of Public Service

Distribution Level Interconnection in New York

New York SIR Overview

- Standardized Interconnection Requirements = SIR
- Latest version of the SIR – October 2018
- Distributed Generation (DG) / Energy Storage Systems (ESS) interconnection up to 5 MW AC proposed to operate in parallel with the distribution system
- Fast track process for projects under 50 kW
- Larger or more complex projects require impact studies
- Action deadlines for developer and utility

SIR - Basic Process

- Submit complete application
- Preliminary, Supplemental screens & CESIR if necessary
- Utilities review and communicate results with applicant
- At each step, look for solutions that allow the project to move to construction
- If solution not found at screening stage, developer must either commit to full study or withdraw

CESIR - System Impact Study

- Coordinated Electric System Interconnection Review = CESIR
- SIR specifies data to be provided by the applicant
- Utility to perform the study within 60 business days
- CESIR report identifies impacts to utility system and necessary system modifications
- Utility also provides cost estimates for system modifications
- Developer has up to 180 business days to make payment or withdraw the application
- Construct and test

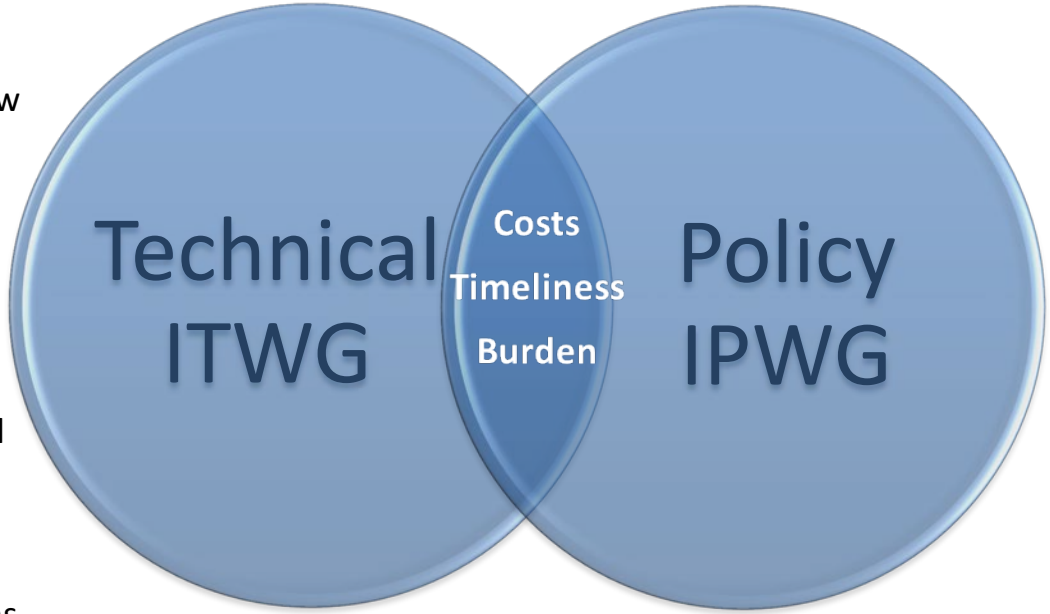
SIR & ESS

- April 2018 Update to SIR addressed inclusion of stand-alone and hybrid (ESS+DG) Energy Storage System projects.
- Maximum export capacity onto utility distribution system is capped at an AC inverter/converter nameplate rating of 5MW.
- ESS in the SIR :
  - New Section I - Part D – Rules for Energy Storage Systems
    - Application Process / Technical Review / Contract & Payment
  - New Appendix A1
    - Standard Interconnection Agreements for ESS
  - New Appendix K
    - ESS Application Requirements
    - System Operating Characteristics
    - Initial Market Participation

Interconnection Working Groups

Technical

- Technical barriers & new technologies
- Consultants – EPRI & Pterra
- SIR screening
- Islanding Protection
- Monitoring and Control
- Voltage Flicker
- Energy Storage
- Metering Configurations



Policy

- Queue management methodology
- Communication
- Policy interpretation, timelines, and stage gates
- VDER / NEM grandfathering
- Insurance requirements
- Material Modifications

NEW YORK STATE OF OPPORTUNITY. Department of Public Service

Technical Working Group (ITWG)

- Goal: identify, discuss, and resolve technical barriers and challenges affecting the interconnection of distributed generation.
- Includes representatives from State agencies, utilities, and DG developers
- Technical consultant (EPRI / Pterra) to assist evaluation process and technical document development
- Initial Topics: Ground Fault Over Voltage (3Vo) / Anti-Islanding Protections (DTT) / Monitoring & Control
- Current Topics: Energy Storage / Voltage Flicker / Transient Over Voltage / Updated Screening
- More information on ITWG at http://www.dps.ny.gov

Policy Working Group (IPWG)

- Goal: develop consensus based solutions and recommendations on policy issues related to the interconnection of DG
- Includes utilities, project developers, trade associations, non-governmental organizations, and customer representatives
- Initial Topics: Queue Management / Cost Sharing / Insurance Requirements
- Current Topics: Material Modifications / Cost Sharing / Contract Requirements/Construction milestones
- More information on IPWG at http://www.dps.ny.gov

DPS Website for DG / DER

Department of Public Service – DG Page

http://www.dps.ny.gov/Electric/DistributedGeneration

More Info

Department of Public Service

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Earth Day 2019: A capacity market first

Monday, April 22, 2019 at 2:11PM
ISO New England in Industry News & Developments, capacity, energy storage, fcm, solar

Every year, ISO New England fields requests from new resources seeking to enter the Forward Capacity Market (FCM). And every year, ISO analysts research those resources to ensure they'll be able to provide the region with the capacity they're promising three years in the future. But what happens when a resource is actually 5,000 individual power systems spread out across four New England states?

That was the case entering the 13th Forward Capacity Auction (FCA #13) when Sunrun became the first company to submit plans to participate with an aggregated collection of residential solar plus storage systems. The company was seeking to qualify its 5,000 systems as demand capacity resources, meaning the company would be responsible for reducing demand on the bulk power grid during peak hours in the summer and winter.

During these hours – 1 to 5 p.m. in the summer and 5 to 7 p.m. in the winter – the company proposes to use the solar plus storage devices to power homes in Massachusetts, New Hampshire, Rhode Island, and Vermont, alleviating the need for those homes to use grid power. The solar battery system, called Brightbox, will average five kilowatts, and will be charged by solar panels installed at the homes.

Though the technology and business plan may have been new – and possibly the first of its kind in the country to participate in a capacity market – the fundamental question facing ISO analysts was a simple one: can the company deliver on what it's promising?

"We used our standard qualification process," said Jennifer Engelson, an energy data analyst at the ISO who oversaw Sunrun's application. "As with all resources, we looked at different facets of the project, starting with the project description. We then reviewed financing and customer acquisition plans, the measurement and verification plan, as well as other project characteristics."

The qualification process was ultimately successful, and Sunrun participated in FCA #13 (held earlier this year in February), securing a 20-megawatt (MW) capacity supply obligation.

Over the next three years, ISO New England will monitor Sunrun's progress installing its Brightbox solar plus battery systems, to ensure they will be available by June 1, 2022, when the company's capacity supply obligation kicks in.

Since the first FCM auction in 2008, more than 200,000 MW of new resources have shown at least initial interest in participating in the market, with more than 29,000 MW progressing all the way through the process and securing capacity obligations. These resources have included many different technologies, including natural gas, onshore and offshore wind, solar, and energy efficiency.

Article originally appeared on ISO Newswire (http://isonewswire.com/).
See website for complete article licensing information.

Implementation of the Revised IEEE Standard 1547

Presentation to NPCC Regional Standards Committee

David Forrest

ISO-NE PUBLIC

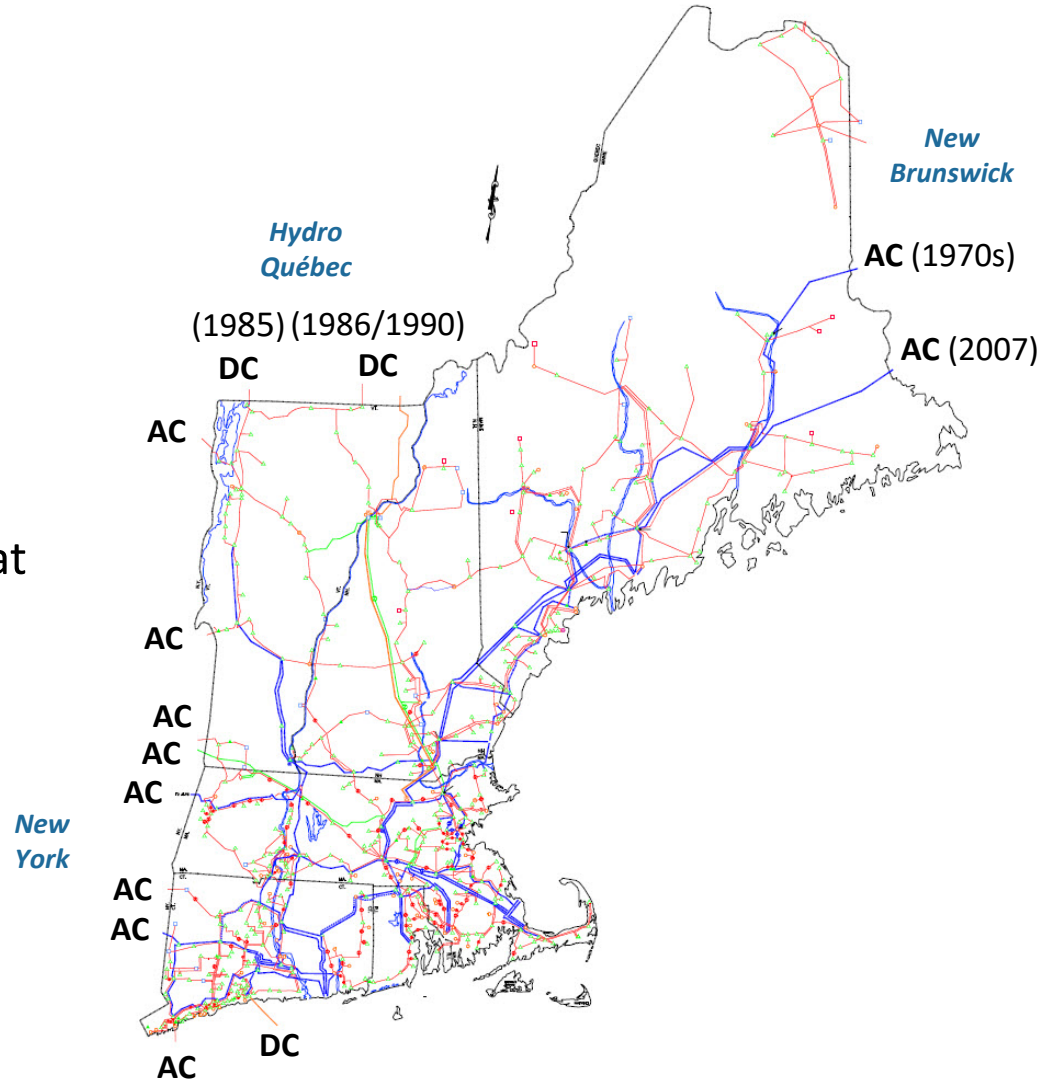
Purpose

- Describe the process ISO New England (ISO-NE) used to implement an interim application of the revised version of IEEE 1547 for solar PV
- Discuss the contents of the Preferred Utility-Required Profile (Preferred URP) which was developed by ISO-NE with the help of Massachusetts utilities and which was titled the “ISO New England Source Requirement Document“
- Share information from the process that might be helpful to other utilities

BACKGROUND

ISO New England

- The ISO-NE region includes the six New England states: Connecticut, Massachusetts, Maine, New Hampshire, Rhode Island and Vermont
- Region's all-time summer peak demand set on August 2, 2006 at **28,130 MW**
- New England's transmission system is tied to neighboring power systems in the U.S. and Eastern Canada:
  - New York (8 AC ties, 1 DC tie)
  - Hydro Québec (2 DC ties)
  - New Brunswick (2 AC ties)

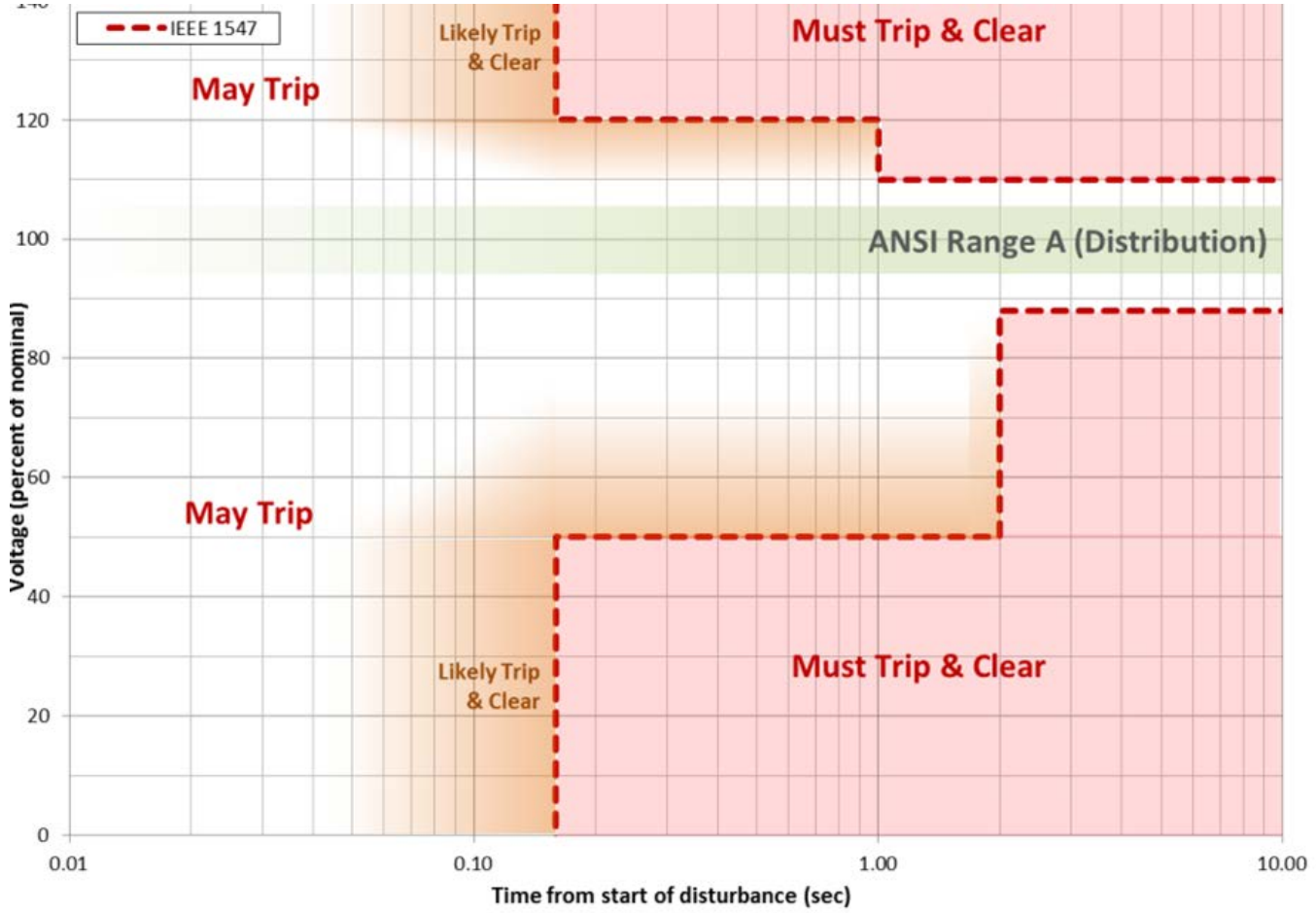


Note: AC stands for Alternating Current and DC stands for Direct Current

Planning for a Large Loss of Supply

- ISO New England plans and operates the transmission system to ensure that the loss of a large source of supply (source loss) does not adversely impact the reliability of the Eastern Interconnection
- Historically, the concern has been source loss due to large generators being disconnected or going unstable and tripping
- Tripping of large quantities of distributed energy resources (DER) for a transmission fault would add to source loss
- If total source loss exceeds the amount allowed by the planning criteria, a system upgrade would be required, and this could negatively impact the benefits of state policies to encourage renewable energy
- The acceptable maximum source loss is limited by the ISO-NE interconnections to other regions, to approx. 1,200 MW for Normal Design Contingencies.

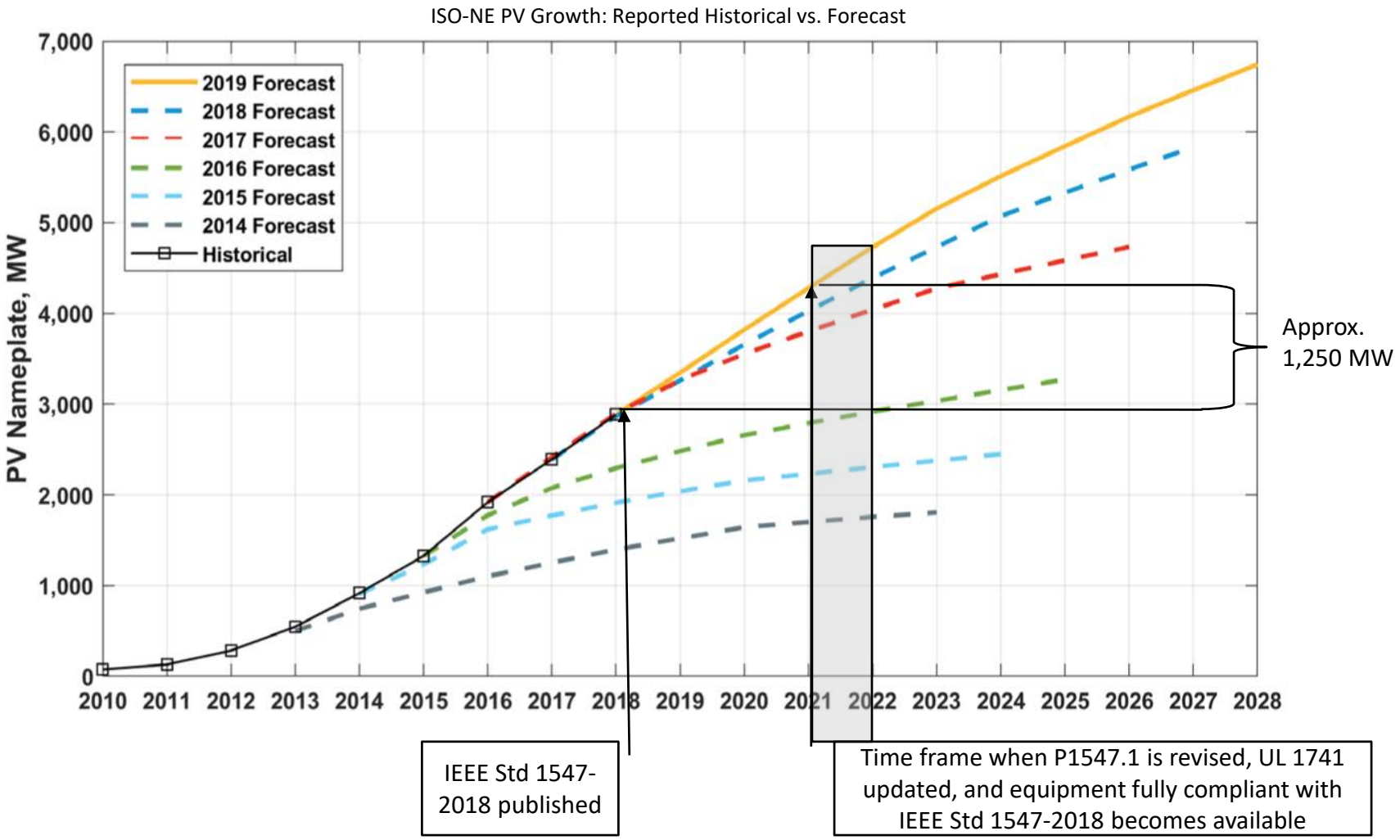
DER could trip before the 1547-2003 trip requirement



Source: Draft NERC IVGTF Task 1-7 report

ISO-NE Forecasts strong growth in Solar DER

ISO Updates the Forecast Annually to Capture Policy Changes



ISO-NE Final 2019 PV Forecast

Cumulative Nameplate, MW_{ac}

States	Cumulative Total MW (AC nameplate rating)										
	Thru 2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
CT	464.3	532.8	623.9	721.4	818.8	890.5	962.1	1033.7	1105.3	1148.8	1190.9
MA	1871.3	2163.2	2451.2	2723.2	2995.2	3267.2	3471.2	3647.2	3817.9	3983.2	4143.2
ME	41.4	48.5	55.7	62.4	69.2	75.9	82.7	89.4	96.2	102.9	109.7
NH	83.8	96.6	109.3	121.4	133.4	145.4	157.5	169.5	181.6	193.6	205.6
RI	116.7	168.0	219.3	267.8	310.2	352.6	395.0	437.4	479.8	522.2	564.6
VT	306.3	337.8	360.3	381.6	402.8	424.1	445.3	466.6	487.8	509.1	530.3
Regional - Cumulative (MW)	**2883.8**	**3346.9**	**3819.8**	**4277.8**	**4729.7**	**5155.7**	**5513.8**	**5843.8**	**6168.5**	**6459.8**	**6744.4**

Notes:

(1) Forecast values include FCM Resources, non-FCM Energy Only Generators, and behind-the-meter PV resources

(2) The forecast reflects discount factors to account for uncertainty in meeting state policy goals

(3) All values represent end-of-year installed capacities

STATUS OF IEEE 1547 AND UL 1741

IEEE 1547

- The approved revision to 1547 underwent final editing at IEEE and was published in early April 2018
- Before DER can be certified as meeting the revised 1547, the testing standard 1547.1 must be revised
- Work on 1547.1 is on-going and will optimistically be completed in the second quarter of 2019
- Once 1547.1 is approved, UL 1741 will need to be updated to agree with the revised 1547.1
- Once UL 1741 is updated and approved, it will take a year or longer for all inverter manufacturers to have their inverters tested and certified
- Thus it will be late 2020 or beyond before utilities will able require use of IEEE 1547-2018

UL 1741

- **UL 1741** is the UL Standard for Safety for Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources
  - The second edition was dated January 28, 2010
  - UL 1741 was revised as of September 7, 2016 to incorporate the new supplement SA
- **UL 1741 SA** defines the requirements for "Grid Support Utility Interactive Inverters"
- These inverters have the capabilities required by California Rule 21 and that meet ISO-NE interim needs
- As of September 9, 2017 inverter-based generation in California is required to be certified as meeting UL 1741 SA

INTERIM SOLUTION

Interim Solution

- Because of the rapid growth of solar PV in New England and because the timeline for full implementation of the revision to IEEE 1547 is 2020 or later, ISO-NE sought out an interim solution for obtaining ride-through for voltage and frequency variations
- Inverters meeting the requirements of UL 1741 SA have the capabilities required by ISO-NE in the interim
- Choosing performance requirements for these inverters required the input from distribution engineers, solar PV developers and inverter manufacturers
- ISO-NE worked with the Massachusetts Technical Standards Review Group (TSRG) to get input from these entities

Interim Solution

- The TSRG is an existing group tasked with addressing distribution interconnection issues
- The TSRG includes representatives from utilities, developers, manufacturers and Massachusetts regulators
- Over 60% of solar PV in New England is/will be installed in Massachusetts
- The TSRG includes representatives from Eversource, which also has subsidiaries in Connecticut and New Hampshire
- The TSRG includes representatives from National Grid, which also has a subsidiary in Rhode Island
- The TSRG includes representatives from Unitil, which also serves customers in New Hampshire

Interim Solution

- Development of inverter performance requirements and an implementation plan required addressing multiple issues
  - Transmission reliability
  - Distribution protection
  - Retaining maximum trip time
  - Anti-islanding protection
  - Conformance with the revised IEEE 1547
  - Allowing time for manufacturers to develop software to implement ISO-NE settings
- Balancing these and other issues ISO-NE and the TSRG developed a Preferred Utility-Required Profile and an implementation plan
  - A summary follows

Interim Solution-Timeline

- The ISO's interim solution was adopted in the 2018 timeframe across multiple utility systems
- The following implementation schedule was implemented in Massachusetts
  - All inverter-based solar PV projects ≤100kW with applications submitted on or after June 1, 2018 are subject to the ISO-NE Source Requirement Document
  - All inverter-based solar PV projects greater than 100kW with applications submitted on or after March 1, 2018 are subject to the ISO-NE Source Requirement Document
  - Inverter-based solar PV projects with applications submitted prior to the above dates were encouraged to comply with the ISO-NE Source Requirement Document with the approval of the interconnecting utility

Interim Solution-Timeline

- National Grid implemented the same requirements as Massachusetts in Rhode Island
- Eversource and United Illuminating required that all Connecticut inverter-based solar PV projects applications submitted on or after June 1, 2018 be subject to the ISO-NE Source Requirement Document
- Eversource and Unitil required that all New Hampshire inverter-based solar PV projects applications submitted on or after June 1, 2018 be subject to the ISO-NE Source Requirement Document
- Maine and Vermont utilities implemented the interim solution as of September 1, 2018 and November 2, 2018 respectively

Interim Solution-Voltage Trip Settings

Shall Trip – IEEE Std 1547-2018 (2nd ed.) Category II					
Shall Trip Function	Required Settings		Comparison to IEEE Std 1547-2018 (2nd ed.) default settings and ranges of allowable settings for Category II		
	Voltage (p.u. of nominal voltage)	Clearing Time(s)	Voltage	Clearing Time(s)	Within ranges of allowable settings?
OV2	1.20	0.16	Identical	Identical	Yes
OV1	1.10	2.0	Identical	Identical	Yes
UV1	0.88	2.0	Higher (default is 0.70 p.u.)	Much shorter (default is 10 s)	Yes
UV2	0.50	1.1	Slightly higher (default is 0.45 p.u.)	Much longer (default is 0.16 s)	Yes

Conflicts with NERC PRC-024-2 but is within limits of IEEE Std 1547.

Interim Solution Voltage Ride-through Capability and Additional Operational Requirements

Voltage Range (p.u.)	Operating Mode/ Response	Minimum Ride-through Time(s) (design criteria)	Maximum Response Time(s) (design criteria)	Comparison to IEEE Std 1547-2018 (2nd ed.) for Category II
V > 1.20	Cease to Energize	N/A	0.16	Identical
1.175 < V ≤ 1.20	Permissive Operation	0.2	N/A	Identical
1.15 < V ≤ 1.175	Permissive Operation	0.5	N/A	Identical
1.10 < V ≤ 1.15	Permissive Operation	1	N/A	Identical
0.88 ≤ V ≤ 1.10	Continuous Operation	infinite	N/A	Identical
0.65 ≤ V < 0.88	Mandatory Operation	Linear slope of 8.7 s/1 p.u. voltage starting at 3 s @ 0.65 p.u.: $T_{VRT} = 3\ \text{s} + \frac{8.7\ \text{s}}{1\ \text{p.u.}}(V - 0.65\ \text{p.u.})$	N/A	Identical
0.45 ≤ V < 0.65	Permissive Operation [a,b]	0.32	N/A	See footnotes a & b
0.30 ≤ V < 0.45	Permissive Operation [b]	0.16	N/A	See footnote b
V < 0.30	Cease to Energize	N/A	0.16	Identical

The following additional operational requirements shall apply for all inverters:

a. **In the Permissive Operation region above 0.5 p.u., inverters shall ride-through in Mandatory Operation mode, and**

b. **In the Permissive Operation region below 0.5 p.u., inverters shall ride-through in Momentary Cessation mode with a maximum response time of 0.083 seconds.**

Interim Solution-Frequency Trip Settings

Shall Trip Function	Required Settings		Comparison to IEEE Std 1547-2018 (2nd ed.) default settings and ranges of allowable settings for Category I, Category II, and Category III		
	Frequency (Hz)	Clearing Time(s)	Frequency	Clearing Time(s)	Within ranges of allowable settings?
OF2	62.0	0.16	Identical	Identical	Yes
OF1	61.2	300.0	Identical	Identical	Yes
UF1	58.5	300.0	Identical	Identical	Yes
UF2	56.5	0.16	Identical	Identical	Yes

Interim Solution-Frequency Ride-through Capability

Frequency Range (Hz)	Operating Mode	Minimum Time(s) (design criteria)	Comparison to IEEE Std 1547-2018 (2nd ed.) for Category II
f > 62.0	No ride-through requirements apply to this range		Identical
61.2 < f ≤ 61.8	Mandatory Operation	299	Identical
58.8 ≤ f ≤ 61.2	Continuous Operation	Infinite	Identical
57.0 ≤ f < 58.8	Mandatory Operation	299	Identical
f < 57.0	No ride-through requirements apply to this range		Identical

Interim Solution-Grid Support Utility Interactive Inverter Functions Status

Function	Default Activation State
SPF, Specified Power Factor	OFF
Q(V), Volt-Var Function with Watt or Var Priority	[1]\ OFF
SS, Soft-Start Ramp Rate	ON Default value: 2% of maximum current output per second
FW, Freq-Watt Function OFF	OFF

LESSONS LEARNED

ISO-NE has benefited from engaging stakeholders on DER standards

ISO-NE has initiated on-going discussions with stakeholders about the need for updating state interconnection requirements to include ride-through for voltage and frequency excursions

- May 16, 2012: Planning Advisory Committee (PAC) meeting
- June 20, 2013: PAC meeting
- September 30, 2013 Distributed Generation Forecast Working Group (DGFWG) meeting
- December 16, 2013: DGFWG meeting
- January 17, 2014: Comments on MA DPU 12-76-A (Grid Modernization)
- January 21, 2014: DGFWG meeting
- April 2, 2014: DGFWG meeting
- April 16, 2014: MA Technical Standard Review Group (TSRG) meeting
- July 11, 2014: PAC and DGFWG meeting
- May 16, 2017:TSRG meeting
- Sept. 14, 2017: Regional System Plan public meeting
- February 14, 2018: PAC meeting

Lessons Learned

- The revised 1547 Annex B recommends that level of penetration be considered in determining the required performance category
  - Solar PV has a high and growing level of penetration in New England
  - Battery storage is also growing
- Some state regulations require compliance with 1547-2003 as updated, choosing trip settings within 1547a ranges may eliminate the need to revise state regulations
- The Energy Policy Act of 2005 requires electric utilities to provide interconnection services “based on standards developed by the Institute of Electrical and Electronics Engineers: IEEE Standard 1547 for Interconnecting Distributed Resources with Electric Power Systems, as they may be amended from time to time.”
  - Public Law 109–58, August 8, 2005

Lessons Learned

- Distribution utilities in New England were already requiring DERs to comply with NPCC frequency trip requirements and thus were not concerned with ISO-NE frequency tripping and ride-through proposed requirements
- Distribution utilities expressed concerns with the impact of high voltages (near 120%) on their and customer equipment
- Distribution utilities requested two-second tripping for 110% voltage to provide back-up protection for SLG faults on distribution circuits
- Distribution utilities accepted a 1.1 second clearing time for voltages 0.5 per unit and below as long as inverters ceased to energize ("Momentary Cessation")
  - Category II can be combined with Momentary Cessation!
- Distribution utilities decided not to implement voltage regulation at this time

Lessons Learned

- Manufacturers requested that ISO-NE develop a source requirement document
- Manufacturers require time to develop a methodology (software) to implement ISO-NE settings in one step
- Developers noted that electricians typically install smaller solar PV projects and are not typically trained to change settings in the field
- Developers noted that ride-through capability may be different for some inverter-based technologies such as fuel cells and combined heat and power that utilizes a synchronous generator connected through an inverter

Lessons Learned

- ISO-NE rejected a proposal to exempt “smaller” solar PV from ride-through requirements based on the total percentage of smaller installations installed as of 2016

New England			
Size Class	Site Count	ACKW	% ACKW
<10kW	87,993	493,701.67	26%
10kW-<20kW	14,471	171,101.46	9%
20kW-<100kW	3,639	133,472.31	7%
100kW-500kW	1,263	291,619.29	15%
>500kW-<1000kW	165	124,246.58	6%
1000kW-<5000kW	315	623,729.13	33%
>=5000kW	13	80,087.30	4%
Total	107,859	1,917,957.74	100%

Lessons Learned

- Small scale solar continues to be the largest percentage of total installations
- Size Class Totals as of 12/31/2018

New England			
Size Class	Site Count	ACKW	% ACKW
<10kW	127,095	727,423.56	24.6%
10kW-<20kW	23,877	274,996.02	9.3%
20kW-<100kW	3,334	148,065.92	5.0%
100kW-500kW	1,893	456,415.09	15.4%
>500kW-<1000kW	277	214,550.77	7.2%
1000kW-<5000kW	493	970,315.75	32.8%
>=5000kW	15	168,156.10	5.7%
Total	156,984	2,959,923.21	100%

Lessons Learned

- ISO-NE choose IEEE 1547 Category II so that trip settings would be within the range of acceptable settings
- The voltage trip settings will result in the following values for DER ride-through performance that may be used by transmission planners in system studies
  - NERC Reliability Guideline on DER Modeling (Sep 2017)
  - EPRI White Paper on New Aggregated DER (der a) Model (May 2018)

Voltage range (p.u.)	Operating Mode / Response	Range of ride-through time (s) (min – max)
V > 1.20	Cease to Energize	N/A
1.175 < V ≤ 1.20	Permissive Operation	0.2 – 2.0
1.15 < V ≤ 1.175	Permissive Operation	0.50 – 2.0
1.10 < V ≤ 1.15	Permissive Operation	1.00 – 2.0
0.88 ≤ V ≤ 1.10	Continuous Operation	Infinite
0.65 ≤ V < 0.88	Mandatory Operation	1.84 – 2.0
0.50 ≤ V < 0.65	Mandatory Operation	0.32 – 2.0
V < 0.50	Momentary Cessation (with a maximum response time of 0.083 seconds)	0.16 – 1.1

NEXT STEPS

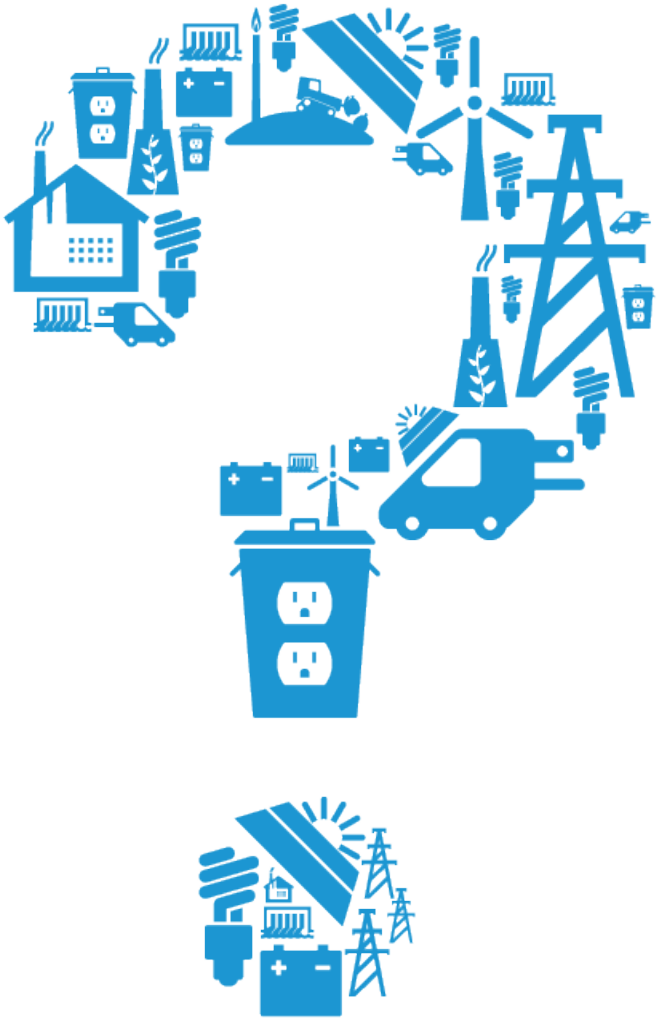
Next Steps

- ISO-NE is working with Municipal Utilities and Co-ops to implement the ISO-NE SRD on their systems
- ISO-NE is working with the MA TSRG on the implementation of 1547-2018
  - Over 50 responsibilities have been identified in IEEE 1547-2018
  - Area EPS Operator has a role in over 40 of these responsibilities, some of which require input from the Regional Reliability Coordinator and the Responsible Transmission Planners
  - A subcommittee of the MA TSRG will meet at least monthly over the next year to make the decisions required for the implementation of 1547-2018

Next Steps -Additional Lessons Learned

- After a few meetings on the implementation of 1547-2018 a few additional issues have surfaced
  - Utilities expressed the need for early identification of required updates to state regulations to allow time for those regulations to be revised
  - Utilities expressed concerns about the interaction between frequency regulation (frequency droop) and anti-islanding protection for existing and new DER
  - Transmission Operators expressed the need for considering 1547-2018 “enter service” settings in black start studies
  - Transmission planners express the need to track the location of the various editions of DER (1547-2003, ISO-NE SRD & 1547-2018)
  - Developers expressed the need to choose communication protocols to allow lead time for the manufacturers

Questions



Northeast Power Coordinating Council, Inc. Regional Standards Committee

Introduction of the DER Forum and Guidance

Guy V. Zito
NPCC AVP - Standards

NPCC Board of Directors Corporate Goals for DER in 2019

NPCC Regional Standards Committee (RSC) Goals:

- Develop a coordinated Regional approach to reliability guidelines for distributed energy resources – by 9/19
- Create a forum under the RSC for DERs and expand coordination on DERs with NAGF, FERC, and NARUC - by 12/19.

NPCC Board of Directors Corporate Goals for DER in 2019 cont.

Other NPCC TFs and WGs Goals

- **Facilitate the integration of Distributed Energy Resources (DER) through promoting and assisting in the coordination of data at the transmission and distribution interface.**
- **Develop acceptable DER model default data for NPCC and test through UFLS sensitivity analysis report findings to RCC at September 2019 meeting and Resolve issues involving the use of a dynamic load model for the NPCC UFLS sensitivity analysis – report findings to RCC at December 2019 meeting**
- **Augment data collection for DERs to evaluate their potential for contributing to Essential Reliability Services, as well as their possible BPS reliability impacts. Evaluate NPCC Long-Range Energy Security and assess fuel availability as a part of evaluating resource adequacy and security.**

NPCC's Role:

- NERC BES as defined and approved by the Commission
- Reliability Standards apply to the BES and elements that affect the "Reliable Operation" of the BES (UFLS-UVLS)
- NPCC UFLS Standard and set of Directory containing Criteria.
- NPCC's Reliability Criteria apply to elements of the BES that have been identified through the application of A-10 BPS and only are enforceable on Full Members (also Tariffs, IAs, etc.)
- As DER penetrates the Distribution system it will begin to have the capability to affect the "Reliable Operation" of the BES/BPS and become the subject of NERC Standards and or Regional Criteria

NPCC RSC Activities to Date:

- **Creation of a form to report Utility Scale Distribution DER impacts on the BES-whether positive or negative-**

DER Impact Reporting Form

- **Creation of a collaborative process between NPCC RSC and Reliability Coordinating Committee (RCC) to identify a path forward to resolve, address or identify if the issue is already being studied or whether it should be NERC or Regional, a standard or guideline.**

Framework for the NPCC RSC Forum:

- Conducted on the second day of all future RSC two-day meetings-subject to need and availability of discussion items. Open and inclusive-WebEx or in person attendance if space is available.
- Provide an atmosphere for open discussion of issues, opportunities and information sharing
- Review any provided DER Impact reported through the online form or via email
- Bring in speakers and develop presentations on topics related to DER to enhance awareness, educate and identify issues
- Discuss how NPCC's groups can help coordinate interoperability between the Transmission ad Distribution for DER related topics
- Create non-mandatory guidance and informational documents to support reliability and security of the BES
- Increase coordination and identify opportunities to work with State and Provincial Regulators and other local efforts in non-jurisdictional areas
- Reduce duplicity, enhance efficiency, leverage technical groups
- Formally add DER forum and guidance to the RSC Scope- ideas??

Opportunities for NPCC Guidance Document(s) on DER:

- Coordinate issues important to BES reliability
- Create a common set of core BES reliability principles pertaining to issues such as interconnection requirements while identifying gaps and best practices in existing documentation across the Areas
- Identify emerging risks and discuss / create paths to mitigate them
- Create suggestions leading to Region wide DER approaches to support reliability and security
- Other documents that may help our member utilities with issues
- Guidance created would be voluntary, informational and non-enforceable. Created using NPCC's "Open Process."

Initial DER Observations for Ongoing Discussion:

- Resource performance on Distribution vs. Transmission, and changing resource mix, reduction in inertia, market dispatch of DER, capacity to provide regulation and reserve, etc.
- Increased penetration of DER on Distribution and the need for Li-Ion Battery-safety issues under study
- Effect on the efficacy of the existing NPCC Regional UFLS programs-how will we deal with high DER penetration on the Distribution system feeders?
- Capacity expansion planning and how DER on the Distribution system will affect the Transmission planning processes
- Interoperability between the Distribution and Transmission System and visibility- forecasting-operational planning and real time operations
- Inverter related to production of Harmonics or Sub-synchronous Resonance on generator shafts

“Intelligence is the ability to adapt to change.”-
Stephen Hawking

Questions or Comments ?

Northeast Power Coordinating Council, Inc. Regional Standards Committee

Herb Schrayshuen

NPCC RSC Distributed Energy Resources (DER) Forum

Potential Gaps

May 16, 2019

Purpose

- Identify emerging risks and discuss / create paths to mitigate them
- Create suggestions leading to Region wide DER related reliability issue or gap filling approaches to support reliability and security
- Establish a process to identify gaps
- Develop an action plan to provide NPCC guidance to stay ahead of the changing resource mix curve.

Types of DER Technology

- Combined heat power
- Fuel cells.
- Hybrid power systems (solar hybrid and wind hybrid systems)
- combined heat and power
- Microturbines
- Solar Photovoltaic systems
  - Utility Scale (5 MW and greater?)
  - Small systems
    - residential rooftop solar PV
    - Commercial rooftop solar PV
- Electric Energy Storage
  - Small
  - Utility scale (5 MW?)
  - Electric Vehicles as storage

Current focus due to inverter technology and Public Policy Drivers

Future focus due to inverter technology and Public Policy Drivers

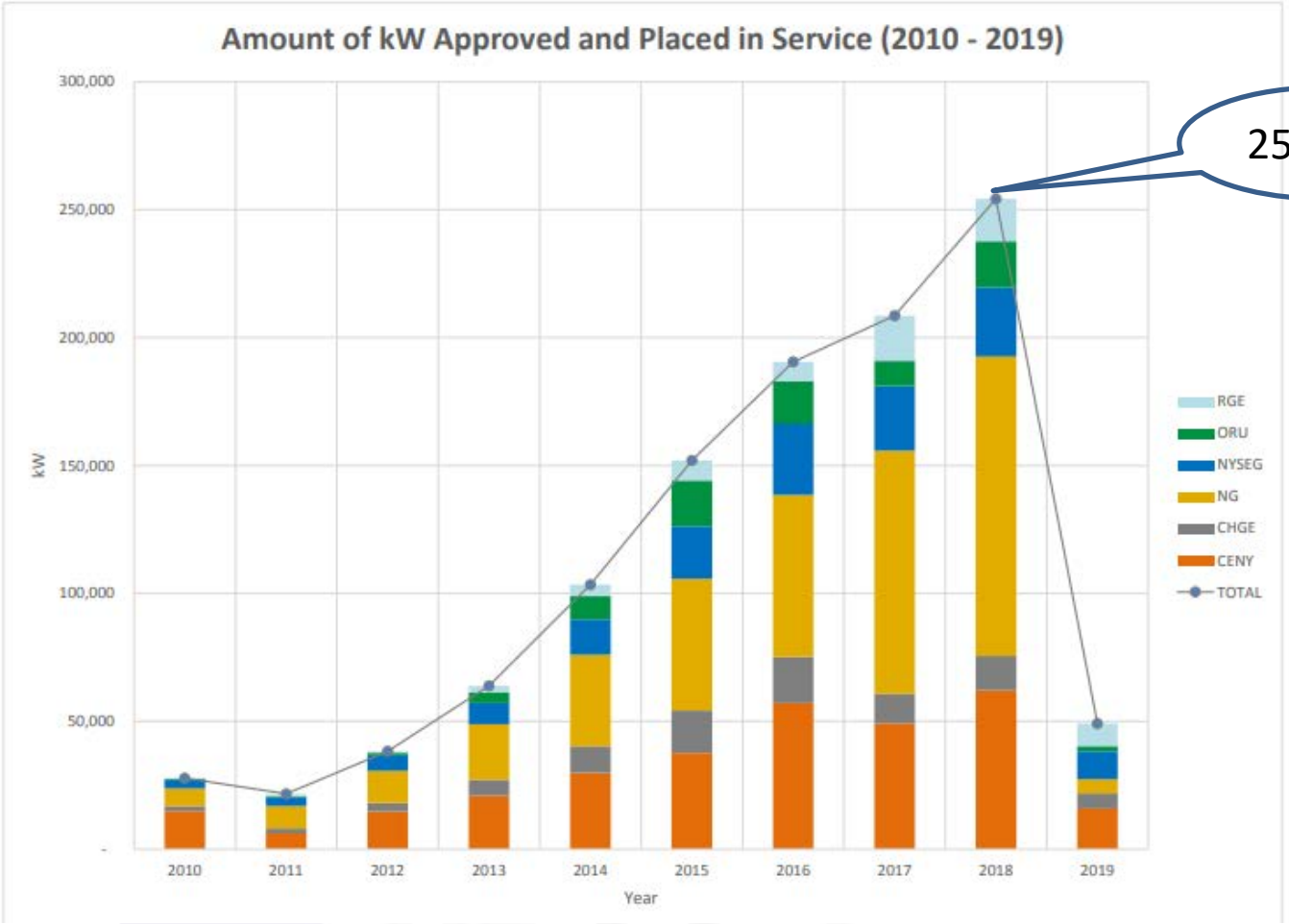
Emerging Risks to Transmission System Reliability

- Visibility of the DER (on distributions system) for:
  - System Planning
  - System Operations
    - E.g. Black Start
  - System Protection system design
  - System dynamic response
- Ability of DER to mask the real load
  - Particularly if the load can be suddenly placed on the distribution or transmission system for common mode loss of the resources (e.g. momentary cessation)
  - Particularly if it impacts UFLS program load assumptions
- Intermittent nature of DER technologies
  - Effective load carrying capacity…at time of system peak. Peak shifting.
- Ability/Inability to model output performance of DER technology
  - Steady state
  - dynamic
- Dynamic Performance of DER technologies.

DER types by connection arrangement

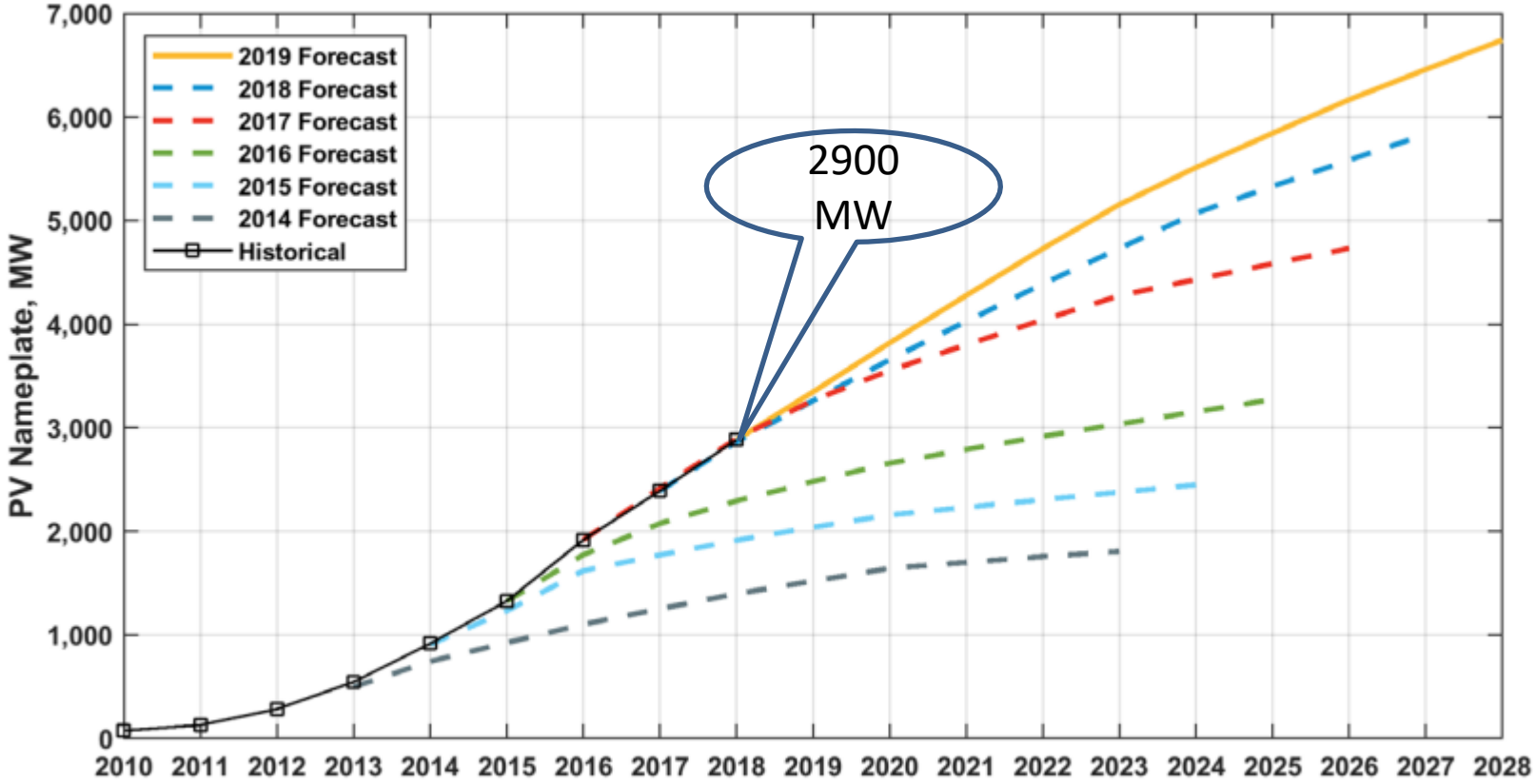
- There are many ways to classify DER.
  - Wholesale
  - Retail
  - Net Metering
  - Behind the retail meter
  - Utility scale (5 MW and greater?)
  - Commercial
  - Behind the meter
  - Queue projects
    - Federal
    - State
    - Utility

What is happening - Example - New York



NY PSC SIR
March 2019

What is Happening – Example – PV AC MW Forecast – ISO-NE



Peak load Reduction-NE

- The installed base of DER MW is not representative of peak demand reduction.

- Example in ISO-NE forecast estimates that relative to peak demand reduction 1MW of Behind the Meter solar may reduce the peak 350 kW*

Reference* ISO-NE final 2019 PV Forecast Page 61

		Cumulative Total MW - Estimated Summer Seasonal Peak Load Reduction										
Category	**States**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
Behind-the-Meter PV	CT	152.9	172.8	180.0	204.6	227.9	245.3	256.8	267.9	278.0	284.1	285.1
	MA	319.4	345.0	392.0	422.8	446.5	468.2	485.8	495.4	501.3	505.7	509.1
	ME	13.7	16.1	17.3	19.0	20.4	21.7	22.8	23.9	24.9	25.9	26.7
	NH	27.2	31.1	34.1	36.7	38.3	39.4	41.2	42.9	44.5	45.9	47.3
	RI	12.5	23.3	29.3	32.1	31.3	33.3	37.1	40.7	44.0	47.0	49.8
	VT	104.5	119.3	124.3	126.4	127.0	127.3	128.4	129.7	130.8	131.7	132.6
Total	**Cumulative**	630.3	707.6	777.2	841.6	891.4	935.2	972.1	1000.5	1023.5	1040.3	1050.6
% of BTM AC nameplate		36.5%	35.2%	33.9%	32.5%	31.2%	29.9%	28.8%	27.8%	26.8%	25.9%	25.1%

Also degrades over time

***Notes*:**

(1) Forecast values are for behind-the-meter PV resources only

(2) Values include the effect of diminishing PV production as increasing PV penetrations shift the timing of peaks later in the day

(3) Values include the effects of an assumed 0.5%/year PV panel degradation rate

(4) All values represent anticipated July 1st installed PV, and are grossed up by 8% to reflect avoided transmission and distribution losses

PRC-024
Is it a ride-through standard or a protection standard?

- Neither PRC-024-2 nor any other NERC Reliability Standards specify or provide acceptable bounds of performance within the “No-Trip” zone.
- Unlike synchronous machines, whose electrical response to fault events is predominantly driven by physics, an inverter-based responses to grid events entirely driven by controls.
- A drafting tem is developing approaches to address the gaps in PRC-024 related inverter based resources and needed clarifications related to the technical content of the standard.
- Among those gaps to be filled is clarifying application of the standard to distributed resources.
- The standard will only apply to BES level resources.
- A webinar took place on May
- Commenting and Balloting (late June) is scheduled

Each distributed generation resource type has its own integration issues

- Inverter Based Resources are a recent focus area due to experience in other systems
  - Interconnection procedures and related technical requirement documents are under review by NPCC
  - So Far:
    - IESO – Appendix F - Inverter Related Revisions
    - ISO-NE Inverter Guideline
    - National Grid Electric System Bulletin
      - NY, MA, RI
    - NY System Interconnection Requirements
  - We are seeking others for NPCC's coordination effort.

Interconnection Process Requirement Topics NY-SIR

- Voltage Response
- Frequency Response
- Reconnection to the System
- Minimum Protective Functions

Interconnection Process Requirement Topics Inverter Based Resources National Grid -NY

- Inverter overview
- Voltage and Frequency Control
- Islanding
- Protection
- Certification

Interconnection Process Requirement Topics Inverter Based Resources - ISO-NE

- Inverter Certification
- Voltage and frequency trip settings for inverter based applications
- Abnormal performance capability (ride-through) requirements for inverter based applications
- Other grid support utility interactive inverter functions statuses

Interconnection Process Requirement Topics Inverter Based Resources - IESO

- Voltage Regulation
- Synchronization
- Monitoring
- Frequency Support
- Distribution Protection Coordination

Interconnection Process Document Thoughts

- Usually interconnection process documents focus on procedure (studies, milestones for example)
- Technical requirements are included, but on an inconsistent level of detail.
- Often references to IEEE standards (e.g. IEEE 1547) or other guides are provided.
  - Canadian references are to national technical requirements (e.g. Canadian Electrical Code CSA C22.3)
- Certification of equipment is also relied on by some.
- These approaches my be too slow given the speed of penetration of equipment.

NERC Inverter-based Resource Performance TF Topics

- NERC IRPTF is developing a Guideline for Interconnection Requirements for BPS-Connected Inverter-Based Resources
- The Task Force is developing a Reliability Guideline
- The Guideline may inform IEEE P2800.1
  - testing standard that "establishes the required interconnection capability and performance criteria for inverter-based resources interconnected with transmission…"

IBRTF Interconnection Requirements Topics

- Momentary Cessation
- Phase Jump Immunity
- Capability curve
- Active Power Frequency Control
- Fast Frequency Response
- Reactive Power Voltage Control
- Reactive Current Voltage control
- Reactive Power at No Active Power Output
- Inverter Current Injection during Fault Conditions
- Return to Service Following Tripping
- Balancing
- Monitoring
- Low Short Circuit Strength Systems
- Fault Ride Through Capability
- Grid forming
- System Restoration and black Start Capability
- Protection Settings
- Power Quality

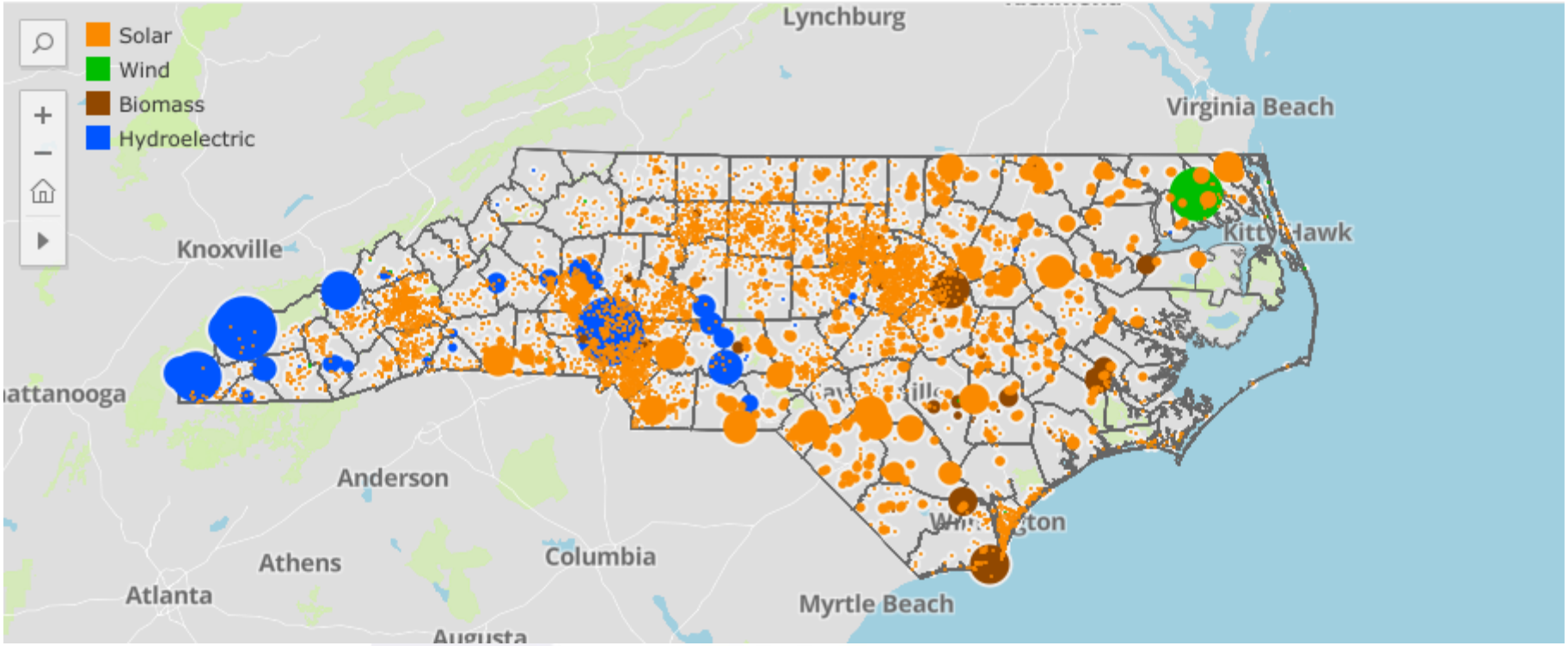
Interconnection Requirements Improvement Topics

- Modelling Improvement Topics
  - Steady State Modelling
  - Dynamics Modelling
  - Short Circuit Modelling
  - Model Benchmarking
  - As built settings and Updated Models.

UFLS Interaction

- Interaction of BTM DER with UFLS
  - Most UFLS processes rely on shedding whole distribution feeders to achieve the goals of the UFLS Program
  - It is important to understand how much load is programmed to be shed at each UFLS block set point
  - To the extent that the load is masked by DER (say in the middle of the day when a disturbance occurs) the amount of load to be shed may not be what the UFLS plan is designed for.
  - UFLS programs should be reviewed (perhaps more frequently than the current five year cycle to assure the amount of load that will be shed is as expected.

Installed Renewable Energy Systems



Potential Gaps (unmitigated risks)
What are the Gaps and Priorities for NPCC

Being Addressed in some Areas

- Forecasting
- Performance at time of peak
- Effective load carrying capability
- Effective load carrying capability
- Performance determination of Solar
- Ride Through (BES Level)

- More TBD

Potentially Not Addressed

- Impact on UFLS Planned Load Shedding Dynamic Performance
- Black Start

- More TBD

Questions?