



Report Items:

- *NPCC BOD Meeting*
- *NERC Standards
Committee Update*
- *ERATF --- Energy
Assurance*



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 #22-1

February 9, 2022, 12:00 p.m. – 4:00 p.m. EDT **WebEx Meeting**

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

Guest Code: 24293984203

Password: 6BTyGukk@38 (62894855 from phone)

[WebEx Link](#)

For Reference:

[Glossary of Terms Used in NERC Reliability Standards](#), dated June 28, 2021

[NPCC Glossary of Terms](#), dated October 2, 2019

Introductions and Chair's Remarks

NPCC Antitrust Compliance Guidelines

Agenda Items:

1.0 Review of Agenda

2.0 RSC Meeting Minutes (Approval Item)

3.0 Items Requiring RSC Discussion

3.1 [NPCC DER Guidance Version #3](#)

3.2 [FERC Activities](#)

3.3 [DER Reporting Form Submission by Power Advisors, LLC](#)

3.4 [Future RSC and DER/VER Forums Schedule](#)

3.5 [NPCC 2022 Corporate Goals](#)

4.0 NERC Reliability Standards

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

4.1 Currently Posted Projects

Project	Comment Period End Date	Ballot Period End Date
<u>Project 2016-02 Modifications to CIP Standards</u> Norm Dang from IESO @ 1:00 PM	9/1/21 (F)	9/1/21 (A)
<u>Project 2017-01 Modifications to BAL-003-1.1</u> David Lemmons from Greybeard Compliance Services @ 1:15 PM	4/27/21 (I)	10/24/19 (F)
<u>Project 2019-04 Modifications to PRC-005-6</u> Giuseppe Giannuzzi from BBA @ 1:30 PM	8/25/21 (F)	

Project 2020-03 Supply Chain Low Impact Revisions Tony Hall @ After 2:30 PM	10/11/21 (F)	10/11/21 (I)
Project 2020-04 Modifications to CIP-012 Ruida Shu	1/24/22 (F)	1/24/22 (A)
Project 2020-05 Modifications to FAC-001-3 and FAC-002-2 SAR Latrice Harkness from NERC @ 2:30 PM	1/31/22 (F)	1/31/22 (I)
Project 2020-06 Verifications of Models and Data for Generators	1/14/21 (I)	
Project 2021-01 Modifications to MOD-025 and PRC-019	4/2/21 (I)	
Project 2021-02 Modifications to VAR-002	5/13/21 (I)	
Project 2021-03 CIP-002 Transmission Owner Control Centers		
Project 2021-04 Modifications to PRC-002-2 Ben Wu from NERC @ 2:15 PM	7/13/21 (F)	
Project 2021-05 Modifications to PRC-023 Ben Wu from NERC @ 2:15 PM	7/28/21 (I)	
Project 2021-06 Modifications to IRO-010 and TOP-003	2/9/22 (I)	
Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination	12/21/21 (I)	
Project 2021-08 Modifications to FAC-008	1/27/22 (I)	
Comments: (I) – Informal; (F) – Formal; (N) – Nomination Period Ballots: (I) – Initial; (A) – Additional; (F) – Final		

- 4.2 Ballot History (Since last RSC Meeting)
- 4.3 Comment Form History (Since last RSC Meeting)

5.0 **NPCC Non-Standards**

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

- 5.1 Items for Discussion
 - 5.1.1 Directory#1 Design and Operation of the BPS --- Jt. Planning/Ops Review
 - 5.1.2 Directory#11 Disturbance Monitoring --- TFSP Review--- Ballot
 - 5.1.3 Directory#8 System Restoration --- TFCO Review
 - 5.1.4 Executive Tracking Summary

6.0 **RSC Member Items of Interest**

- 6.1 RSC Roster

7.0 **Standards Activity Post NERC BOT Approval**

(Since last RSC Meeting)

- 7.1 NERC Filings to FERC
<http://www.nerc.com/FilingsOrders/Pages/default.aspx>
- 7.2 FERC Orders / Rules
<http://www.nerc.com/FilingsOrders/Pages/default.aspx>
- 7.3 Federal Register
<https://www.federalregister.gov/>
- 7.4 [FERC Sunshine Act Meeting Notice](#)

7.5 FERC Open Meeting Summaries

8.0 NERC Meetings

8.1 Standards Committee (SC)

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

January 19 th – Call	February 16 th – Call	March 23 th – Call
April 20 th – Call	May 18 th – Call	June 15 th – Call
July 20 th	August 17 th – Call	September 21 st
October 19 th – Call	November 17 th – Call	December 13 th

8.2 Board of Trustees (BOT) Meeting

<http://www.nerc.com/gov/bot/Pages/Agenda-Highlights-and-Minutes-.aspx>

February 9-10	May 11-12	August 17-18
November 4-5 – Conference Call/Virtual		

9.0 NERC Items of Interest (Since last RSC Meeting)

9.1 Lessons Learned

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

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

9.2 Alerts

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

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

9.3 NERC Reliability and Security Guidelines

<https://www.nerc.com/comm/Pages/Reliability-and-Security-Guidelines.aspx>

9.4 NERC Rules of Procedure

<https://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx>

10.0 Future RSC Meetings and Conference Calls

10.1 RSC 2022 Meeting Dates

February 9 th , WebEx
May 11 th -12 th , WebEx
August 10-11 th WebEx or Toronto
October 12 th -13 th WebEx or NYPA
December 1 st General Meeting or WebEx

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 General Counsel and Corporate Secretary, Kristin McKeown Esq. at her mobile phone number 646-581-0148.

Public Announcement

RSC and DER/VER Forum Meetings, WebEx, and Conference calls:

Participants are reminded that this meeting, WebEx, and conference call are public. The access number was posted on the NPCC website and widely distributed. Speakers on the call should keep in mind that the listening audience may include members of the press and representatives of various governmental authorities, in addition to the expected participation by industry stakeholders.



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NPCC REGIONAL STANDARDS COMMITTEE

AGENDA FOR MEETING #21-5

December 2, 2021, 12:00 p.m. – 4:00 p.m. EDT **WebEx Meeting**

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

Guest Code: 24299943928

Password: 9AiCidsU3\$8 (92424378 from phone)

[WebEx Link](#)

For Reference:

[Glossary of Terms Used in NERC Reliability Standards](#), dated June 28, 2021

[NPCC Glossary of Terms](#), dated October 2, 2019

Attendance:

	Name	Organization	Sector(s)	Day(s)
1.	Gerry Dunbar	Northeast Power Coordinating Council		1
2.	Ruida Shu	Northeast Power Coordinating Council		1
3.	Kal Ayoub	FERC	Guest	1
4.	Arthur Brown		Guest	1
5.	Brian Robinson	Utility Services, Inc.	5	1
6.	Catherine Ethier	Ontario Energy Board	Guest	1
7.	Chantal Mazza	Hydro Quebec	2	1
8.	Cristhian Godoy	Consolidated Edison Co. of New York, Inc.	5	1
9.	Dan Kopin	VELCO	Guest	1
10.	Dave Kwan	Ontario Power Generation	4	1
11.	David Kiguel	Independent	7	1
12.	Donald Nelson	Mass DPU	Guest	1
13.	Glenroy Smith	Entergy	4	1
14.	Herb Schrayshuen	Power Advisors, LLC	Guest	1
15.	James Grant	NYISO	2	1
16.	Joel Charlebois	AESI	7	1
17.	John Pearson	ISO-NE	2	1
18.	Junji Yamaguchi	Hydro Quebec	1	1
19.	Kaitlin Nadeau		Guest	1
20.	Lodie White	FERC	Guest	1
21.	Michael Foley	Con Edison	4	1

22.	Mike Ridolfino	Central Hudson Gas and Electric	1	1
23.	Michele Shafer	The United Illuminating Company	1	1
24.	Michael Tondalo	The United Illuminating Company	1	1
25.	Michael Jones	National Grid	3	1
26.	Nurul Abser	NB Power	1	1
27.	Payam Farahbakhsh	Hydro One Networks	1	1
28.	Quintin Lee	Eversource	1	1
29.	Rob Vance	New Brunswick Power	1	1
30.	Sarat Chakravadhanula	Eversource	Guest	1
31.	Salvatore Spagnolo	NYPA	4	1
32.	Sean Lagan	IESO	2	1
33.	Timothy Kucey	PSEG	4	1
34.	Vijay Puran	NYDPS	Guest	1
35.	Norm Dang	IESO	Guest	1
36.	David Lemmons	Cooper Compliance	Guest	1
37.	Giuseppe Giannuzzi	Hydro Quebec	Guest	1
38.	Tony Hall	LGE-KU	Guest	1
39.	Joseph Gatten	Xcel Energy	Guest	1
40.	Ben Wu	NERC	Guest	1

Introductions and Chair's Remarks

Gerry Dunbar provided remarks on NERC standard development activities.

NPCC Antitrust Compliance Guidelines

The NPCC Antitrust Compliance Guidelines were read by Ruida Shu.

Agenda Items:

1.0 Review of Agenda

2.0 RSC Meeting Minutes (Approval Item)

Approval of the October 13-14, 2021, RSC and DER Forum meeting minutes – No revision is necessary to the draft RSC meeting minutes that were provided in the agenda package.

Mike Jones made the motion for approval.

David Kwan seconded the motion.

The October 13-14, 2021, RSC and DER Forum meeting minutes were approved.

3.0 Items Requiring RSC Discussion/Approval/Endorsement

3.1 NPCC DER Guidance Version #3 (Approval to Post for Open Process)

Approval to post for an open process: NPCC DER Guidance Document Version #3.

Mike Jones made the motion for approval.

Joel Charlebois seconded the motion.

NPCC DER Guidance Document Version #3 is approved to post for an open process. The plan is to post this document on December 14, 2021.

3.2 FERC Activities (Discussion)

Kal Ayoub presented on the recent FERC activities.

He reviewed the FERC and NERC work opportunities, Technical Conference on Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, Joint FERC-NERC Inquiry into February 2021 Cold Weather Event and Related Actions, Improving Winter-readiness of Generating Units, and 2021-2022 Winter Energy Market & Reliability Assessment Presentation.

3.3 RSC Scope of Work (Approval)

Approval of the RSC Scope of Work.

Jim Grant made the motion for approval.

Quintin Lee seconded the motion.

The RSC Scope of Work is approved as read.

3.4 RSC Work Plan (Approval)

Approval of the RSC Work Plan.

Jim Grant made the motion for approval.

Quintin Lee seconded the motion.

The RSC Work Plan is approved as read.

3.5 DER Reporting Form Submission by Power Advisors, LLC (Discussion)

The RSC members reviewed and discussed the concerns regarding the impact of DER on UFLS.

Gerry Dunbar will take this concern and forward it to the appropriate task force(s).

3.6 NPCC Corporate Goal II-2 Long Term Strategic Recommendations (Endorsement)

The RSC members reviewed and discussed TFSP's recommendation to endorse the long-term strategic recommendations that were developed in response to NPCC Corporate Goal II-2 "Develop long-term strategic reliability recommendations incorporating input from state and provincial regulators relating to their decarbonization goals for RSC and RCC endorsement."

In response to outreach to state and provincial regulators, the following long-term strategic reliability recommendations were developed:

To promote better understanding among NPCC stakeholders and state/provincial regulators ongoing communication should take place on the following topics:

1) Effective regional transmission planning in the face of the changing resource mix and public policy decarbonization goals with respect to ensuring a reliable BPS.

Promote awareness and assessment of short, medium, and long-term regional transmission planning and expansion through an NPCC Working Group or Forum.

2) The impact of emerging technologies necessary to meet total demand due to electrification of the building and transport sectors. Promote consistency in regional assessments to ensure that the assumptions surrounding these new technologies are

dependable and transparent. Ensure that these resources adequately support reliability both now and in the future as electrification proceeds.

3) Promotion and coordination of risk-informed portfolio of resources that recognize the

interdependence between gas supply and electric demand. Focus should be paid to the operability of the BPS with respect to the integration of DER/VER.

NPCC Corporate Goal II-2 has been met.

Dan Kopin made the motion for endorsement.

Mike Jones seconded the motion.

NPCC Corporate Goal II-2 Long Term Strategic Recommendations is endorsed as read.

4.0 **NERC Reliability Standards**

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

4.1 Currently Posted Projects

Project	Comment Period End Date	Ballot Period End Date
Project 2016-02 Modifications to CIP Standards Norm Dang from IESO @ 1:00 PM	9/1/21 (F)	9/1/21 (A)
Project 2017-01 Modifications to BAL-003-1.1 David Lemmons from Cooper Compliance @ 1:15 PM	4/27/21 (I)	10/24/19 (F)
Project 2019-04 Modifications to PRC-005-6 Giuseppe Giannuzzi from BBA @ 1:30 PM	8/25/21 (F)	
Project 2020-03 Supply Chain Low Impact Revisions Tony Hall @ 1:45 PM	10/11/21 (F)	10/11/21 (I)
Project 2020-04 Modifications to CIP-012 Joseph Gatten from Xcel Energy @ 2:00 PM	6/9/21 (F)	
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Project 2021-05 Modifications to PRC-023 Ben Wu from NERC @ 2:15 PM	7/28/21 (I)	
Project 2021-06 Modifications to IRO-010 and TOP-003	8/6/21 (I)	
Comments: (I) – Informal; (F) – Formal; (N) – Nomination Period Ballots: (I) – Initial; (A) – Additional; (F) – Final		

Project 2016-02 Modifications to CIP Standards:

Proposed definition rework:

Shared Cyber Infrastructure: Only the that portion of an entity's virtualization infrastructure that is supporting NERC related systems (i.e., the "mixed trust" components)
Electronic Security Perimeter: to incorporate old definition verbatim with additional a zero trust / virtualization component
External Routable Connectivity: restored to be like the existing definition
Interactive Remote Access: simplified/ clarified. Removed management of existing EACMS/ firewalls for better backwards compatibility
Conforming change to match the changed definitions: CIP-005: Restoration of the structure to R1.1 and R1.2 (to be similar as currently approved standard). R2 EACMS management removed from IRA
CIP-007/CIP-010 – still being looked at.

Project 2017-01 Modifications to BAL-003-1.1:
In the process of modifying the standard.
The SDT is in the process of modifying frequency demand, frequency bias setting.
These forms are being used for entities to provide frequency response information to BA.
The drafting team is looking to find out if NERC can collect the frequency response information using the 1600 data request instead of using the forms.

Project 2019-04 Modifications to PRC-005-6:
PRC-005-6 SAR Overview:
The SAR was presented to the NERC Standard Committee (SC) on October 20, 2021.
A PowerPoint presentation was prepared to the SC and publicly available.
https://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/SC_Agenda_Package_October_20_2021.pdf
The project was approved by the Standard Committee (SC).
There is a Supplemental Nomination Period Open through December 15, 2021.
The SC would like to add additional members to the SDT with transmission and distribution protection expertise as well as Protection System station direct current (DC) supply technologies.
Summary of the NAGF SAR: Revise PRC-005-6 to clearly define the applicability of Protection Systems associated with AVR protective functions. In addition, revise the PRC-005-6 Supplementary Reference and FAQ to provide additional guidance related to AVR protective functions and acceptable methods of testing to meet PRC-005-6 required maintenance activities.
Summary: Confusion about protective functions exists despite the response to the 2016 RFI.
It is crucial that this issue be clarified by including it within PRC-005.
SAR Drafting Team carefully considered all comments received from Industry and edited the SAR in response to those comments.
There is a Supplemental Nomination Period Open through December 15, 2021.
The SC would like to add additional members to the SDT with transmission and distribution protection expertise as well as Protection System station direct current (DC) supply technologies

Project 2020-03 Supply Chain Low Impact Revisions:
Section 6: Vendor communication controls: For assets containing low impact BES Cyber System(s) identified pursuant to CIP-002, the Responsible Entity shall implement a process to mitigate risks associated with vendor's electronic access. This process must address:

- 6.1 Having one or more method(s) for determining vendor electronic access to low impact BES Cyber Systems via electronic access controls established in Section 3;
- 6.2 Having one or more method(s) for disabling vendor electronic access established in Section 6; and
- 6.3 Having one or more method(s) for detecting known or suspected malicious communications for both inbound and outbound communications.

The project will be posted for comments and ballot after Project 2020-04 comment and ballot period concludes.

Project 2020-04 Modifications to CIP-012:

The project is posted for comment and ballot.

The SDT made changes to R1 with updates focusing on the loss of the ability of data, methods to be used for the recovery of communication links used to transmit, identification of where the Responsible Entity applied security, and availability protection(s).

R2 is also removed from the standard.

Project 2020-05 Modifications to FAC-001-3 and FAC-002-2:

The drafting team is posting the Standard and Implementation plan for a 45-day formal comment and initial ballot period on December 6th. To address the ambiguity in the SAR regarding the term "materially modified", the team modified the standards to remove "materially modified" and replaced it with "qualified change." In addition, a new Requirement R6 in FAC-002-4 was added for the Planning Coordinator to be the one defining qualified change for its area.

Project 2020-06 Verifications of Models and Data for Generators:

The revised SARs were accepted by the SC on July 21, 2021. The SARs propose revisions to MOD-026-1 and MOD-027-1 to clarify requirements related to IBRs and to require sufficient model verification to ensure accurate generator representation in dynamic simulations.

The Standard Drafting Team has held public meetings to discuss the revisions to MOD-026/027.

Projected date for initial posting of revised standards is March 2022.

Next meeting is coming up in mid-December. A formal announcement will be sent.

Project 2021-01 Modifications to MOD-025 and PRC-019:

The SAR DT was appointed at the July 21, 2021, SC meeting. The SAR DT reviewed and responded to industry comments, revised the MOD-025 & PRC-019 SARs, and will seek SC endorsement of the revised SARs at the December SC meeting.

Background: The PPMVTF developed this SAR to revise MOD-025-2 to address issues regarding verification and data reporting of generator active and reactive power capability. As stated in the SAR, implementation of the standard has rarely produced data that is suitable for planning models (i.e., the stated purpose of the standard). PRC-019-2 was developed with a bias toward synchronous generation and does not sufficiently outline the requirements for all generation resource types. The proposed SAR aims to address several issues identified by the SPCS and revise the standard to be inclusive of all types of generation resources.

Project 2021-02 Modifications to VAR-002-4.1:

This SAR proposes to revise VAR-002-4.1 to address ambiguities within the existing standard. To clarify VAR-002-4.1, Requirement R3, regarding whether the GOP of a dispersed power

resource must notify its associated TOP upon a status change of a voltage controlling device on an individual generating unit. The team is reviewing industry comments and in the process of schedule the next SAR drafting team meetings.

Project 2021-03 CIP-002 Transmission Owner Control Centers:

The drafting team had its TOCC Project Plan approved by the RSTC and the Standards Committee. Next steps are to gather field test participants and have the list finalized by December 31, 2021. The field test plan and schedule are posted on the project page.

Project 2021-06 Modifications to IRO-010 and TOP-003:

The primary purpose of this project is to simplify administrative burdens identified by the SER Phase 2 Team associated with the current IRO-010-3 and TOP-003-4 standards and limit unnecessary data requirements that do not contribute to BES reliability and resiliency. SAR drafting team was approved at September 2021 SC meeting. Kick off meeting was on October 13, 2021, the team has completed revising the SAR and are working on responding to comments. The redlined SAR and consideration of comments will post for a second comment period on January 18th 2022.

4.2 Ballot History (Since last RSC Meeting)

Ruida Shu reviewed the Ballot History document in the meeting.

4.3 Comment Form History (Since last RSC Meeting)

Ruida Shu reviewed the Comment Form History document in the meeting.

5.0 NPCC Non-Standards

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

5.1 Items for Discussion

5.1.1 Directory#1 Design and Operation of the BPS --- Jt. Planning/Ops Review

The Jt. Planning and Operations review of Directory #1 by a TFCP/TFCO Joint Working Group continues. Initial posting anticipated in the second half of 2022.

5.1.2 Directory#12 UFLS --- Retirement

Directory #12 has been retired effective October 1, 2021. The NPCC Full Member Committee approved the retirement on October 19, 2021, to coincide with the enforcement date of PRC-006-NPCC-02 in all regional jurisdictions. NPCC Directory #12 has been archived on the NPCC website with a 'retired' watermark

5.1.3 Directory#11 Disturbance Monitoring --- TFSP Review

TFSP has reviewed and updated Directory#11 in accordance with the normal review cycle of the document. RCC approved the revised draft of D311 on 11/30/22 and a Full Member ballot will be conducted in early 2022.

5.1.4 Directory#8 System Restoration --- TFCO Review

The TFCO and its CO-11 Working Group have reviewed and updated the document. TFCO anticipates posting Directory #8 for Member comment during the 1st Quarter of 2022.

5.1.5 Executive Tracking Summary

6.0 RSC Member Items of Interest

6.1 RSC Roster

7.0 Standards Activity Post NERC BOT Approval

(Since last RSC Meeting)

7.1 NERC Filings to FERC

<http://www.nerc.com/FilingsOrders/Pages/default.aspx>

7.2 FERC Orders / Rules

<http://www.nerc.com/FilingsOrders/Pages/default.aspx>

7.3 Federal Register

<https://www.federalregister.gov/>

7.4 FERC Sunshine Act Meeting Notice

7.5 FERC Open Meeting Summaries

8.0 NERC Meetings

8.1 Standards Committee (SC)

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

January 20 th – Call	February 17 th – Call	March 17 th – Call
April 21 st – Call	May 19 th – Call	June 16 th – Denver, CO (Xcel Energy)
July 21 st – Call	August 18 th – Call	September 23 rd – Salt Lake City, UT (WECC)
October 20 th – Call	November 17 th – Call	December 15 th – Atlanta, GA (NERC)

8.2 Board of Trustees (BOT) Meeting

<http://www.nerc.com/gov/bot/Pages/Agenda-Highlights-and-Minutes-.aspx>

February 5-6 - Meeting	May 13-14 - Meeting	August 19-20 – Conference Call
November 4-5 – Conference Call		

9.0 NERC Items of Interest (Since last RSC Meeting)

9.1 Lessons Learned

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

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

9.2 Alerts

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

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

9.3 NERC Reliability and Security Guidelines

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9.4 NERC Rules of Procedure

<https://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx>

10.0 Other Items of Interest

10.1 NPCC Board of Directors Meeting (BOD) 2021

January 27 th – SGR Law Offices, Jacksonville, FL	March 17 th - Call	May 5 th – NPCC Office
June 2 nd – Call	June 23 rd – NPCC Office	August 4 th – Call
September 1 st and 2 nd – Pierce Atwood	October 27 th – Call	December 1 st – Halifax, NS

11.0 Future RSC Meetings and Conference Calls

11.1 RSC 2021 Meeting Dates

February 10 th -11 th , WebEx
May 12 th -13 th , WebEx
August 11 th WebEx
October 13 th -14 th WebEx
December 2 nd General Meeting or WebEx

11.2 RSC 2022 Meeting Dates

February 9 th -10 th , WebEx
May 11 th -12 th , WebEx
August 10 th WebEx
October 12 th -13 th WebEx
December 1 st General Meeting or WebEx

The meeting is adjourned at 4:23 PM.

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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;
- Limiting production;
- Whether or not to deal with any company; and
- Any competitively sensitive information concerning their company or a competitor.

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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 General Counsel and Corporate Secretary, Kristin McKeown Esq. at her mobile phone number 646-581-0148.

Distributed Energy Resources Forum Disclaimer Statement

1. General

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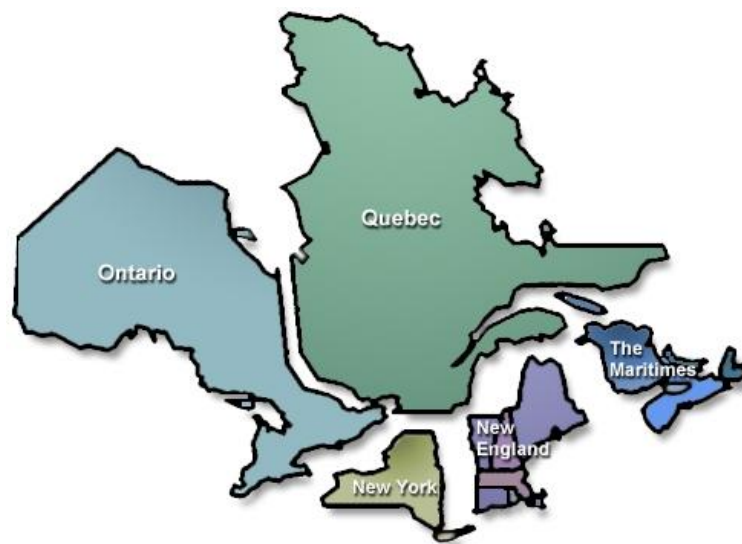
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NPCC DER Guidance Document, Distributed Energy Resources (DER) Considerations to Optimize and Enhance System Resilience and Reliability



NPCC Regional Standards Committee (RSC)
Version 3 Approved _____

Note: Content of this document may not reflect the most current information¹. Periodic reviews for potential revisions of the document will be done biannually or more frequently if needed. Please send corrections or revision requests to npccstandard@npcc.org.

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Revision History

Version	Date	Action	Change
1	8/19/19	Effective Date	New
2	11/3/20	RSC and Subgroup developed revisions	Revisions, add AGIR, new title, clarifications, and Appendices
3	XX/XX/XX	Walling Energy Systems Consulting, LLC developed revisions	Substantial revision and reorganization of the document. Additions of major sections on DER characteristics and capabilities, resource planning impacts, DER aggregation, interconnection standards, and a new appendix summarizing transmission-connected inverter-based resources

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Executive Summary

The Northeast Power Coordinating Council, Inc. (NPCC) is responsible for promoting and enhancing the reliability of the International, interconnected Bulk Power System in Northeastern North America.

Development of this document was initiated by the NPCC Board of Directors to provide regional guidance and information for voluntary use by NPCC Members and stakeholders. The guidance provided herein identifies potential reliability risks² to the Bulk Power Systems (BPS), recommendations to mitigate them, and also identifies opportunities to optimize the operational characteristics of DER to enhance reliability and resilience of the NPCC Bulk Power System (BPS).³ The document outlines both existing DER deployment practices and strategies as well as how a future with increased penetration of DER and internet controllable devices could be reliably coordinated ([Appendix H](#)). Links to other resources have also been provided throughout the document.

As Distributed Energy Resources (DER) continue to replace traditional industry generation resources, the resource fuel mix and operational characteristics of the system will change. DER will necessitate changes to how the system is planned and operated. The North American Electric Reliability Corporation (NERC) Reliability Standards are not applicable to equipment on the distribution systems unless such equipment has a direct impact on the “reliable operation”⁴ of the BPS, such as Automatic Underfrequency Load Shedding (UFLS). However, as penetration of DER increases, planning and operating assessments used to assure reliable operation of the BPS will need to accurately represent how DER interacts with the BPS.

NPCC recognizes that continent-wide efforts in North America are underway at the NERC level to define DER and address some aspects related to planning and modeling. [Appendix C](#) outlines some specific reliability activities related to DER which have either been developed, or are in the process of being developed, by the NERC System Planning Impacts from Distributed Energy Resources Working Group (SPIDER WG), along with links to some of their documents. NPCC and its members have also been engaged in the work efforts at the NERC level and are leading efforts to address outstanding issues within the scope of those groups and provide expertise. With the understanding of all the efforts which are underway, NPCC can coordinate and fill a vital role in identifying additional areas where the Region may provide information and services to promote reliable deployment of DER. An example is coordination with State and Provincial Government Regulatory Authorities, and distribution utilities. Also, opportunities exist in the areas of obtaining data, models, testing and verification, observability,

² An example of a reliability risk not addressed is remote dispatch of DER. A significant challenge that has been found by some NPCC members is that DER Operators can be anywhere in the world and that as a result, communications can be significantly delayed, leading to reliability risks. This includes time zone challenges and language challenges,

³ Prior versions of this document had significant content related to DER interconnection practices that are not of direct or indirect consequence to BPS reliability. In the interests of focusing this document on BPS issues, this material has been intentionally omitted from this version.

⁴ “reliable operation” is defined in 16 U.S. Code § 824o and means “operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.”

protection systems and other operational characteristics of DER and their effect on the distribution systems.

NPCC has also been conducting DER Forums, the purpose of which is to promulgate DER related information, educate, and inform. NPCC's Regional Standards Committee (RSC) and Reliability Coordinating Committee (RCC) have also developed a joint process and a form to report DER related impacts (i.e. during or following an event both enhancing reliability or causing a reliability risk) and analyze and determine if any further actions are needed. The Form and process may be found in [Appendix A](#) and on the NPCC website.

NPCC is not creating new Criteria or Standards through this guidance document. The intent of this document is informational and as NERC's SPIDERWG, and other groups develop their respective guidance documents it will be revised to achieve continued alignment and avoid duplication.

This guidance document contains [DER Recommendations](#), and information provided by NPCC's Members, NERC, the industry, the US National Renewable Energy Labs, the Electric Power Research Institute (EPRI) and information from NPCC Staff. Also, it is important to note that specific distribution utility requirements within NPCC at the local level will supersede any suggested approaches in this document.

In addition to the growth in DER penetration, there has been a rapid increase in transmission-connected inverter-based resources (IBR), of which the majority can also be characterized as non-dispatchable variable energy resources (VER). There are many similarities, as well as substantial differences, between DER and IBR/VER with regard to impacts on bulk system security. DER issues are largely framed by the relevant interconnection standards for DER, and different standards apply to transmission connected resources. Therefore, the main body of this document is focused exclusively on DER. A summary of significant differences and similarities in BPS security concerns between DER and transmission-connected IBR is provided for information in [Appendix I](#). This appendix may form the basis of a future NPCC document focused on transmission-connected resources.

Introduction and Objective

A consistent defined term for what type of generating, demand modification, or energy storage resources are included in DER is not broadly accepted by industry stakeholders. Also, DER is not currently a term that is defined by NERC in the *Glossary of Terms Used in NERC Reliability Standards*. However, the NERC report Distributed Energy Resources Connection Modeling and Reliability Considerations, produced by NERC's former DER Task Force, defines DER as

A Distributed Energy Resource (DER) is any resource on the distribution system that produces electricity and is not otherwise included in the formal NERC definition of the Bulk Electric System (BES).

It should be noted that the Federal Energy Regulatory Commission (FERC) and other policy and regulatory bodies have used a much broader definition of DER that includes "resources" that do not inject current or produce electricity, such as demand response and energy conservation. This ambiguity

in the DER definition used in various parts of the industry is, unfortunately, a source of potential confusion. For the purpose of this NPCC guidance document, DER refers to:

Any non-BPS connected real or reactive power resources (generating units, multiple generating units at a single location, distributed generation installations, battery storage systems, etc.) located within the boundary of any distribution utility's service territory, regardless of capacity, allowing individual DER to be captured if they are not aggregated.

While power variability is not inherent to the definition of DER, the practical fact is that a large portion of DER (primarily photovoltaic, or PV) are more intermittent in their production characteristics than conventional resources which operate based on a controllable fuel input.

Initially, in the first version of this guidance document, NPCC specified a threshold for inclusion of DER in any regional guidance that would not include individual rooftop solar or individual wind turbines or other DER net metering installations. However, the aggregate effect of these types of DER can have a significant effect on the power system and if not properly understood can impact the reliable operation of the BPS, as we have seen in California subsequent to their Rule 21⁵. NPCC is now beginning to observe aggregations of DER entering into the capacity wholesale markets within the NPCC Region. This document will continue to be modified as emerging issues related to DER's deployment, interconnection, planning and operations are identified and technology improves.

As DER continues to proliferate on the electric system at the "grid edge" or distribution system, and replace conventional transmission grid connected resources, there is an increasing reliability-related need to understand the characteristics of various types and technologies of DER and their impacts on the BPS. It is important to understand how DER is interconnected, planned, operated and how DER interacts with the transmission system.

International standards are established to address DER performance characteristics and capabilities, including their impact on system reliability. Recent major changes to these standards have been made to address BPS reliability issues, which were not considered in earlier standards developed prior to significant DER penetration. IEEE 1547-2018 as amended by IEEE 1547a-2020 brings significant potential benefits to the BPS by requiring that DER provide essential reliability services to ensure stability, reliability, and security. State and Provincial requirements for DER interconnection should also require compliance with IEEE 1547-2018 through inclusion in their respective jurisdictional interconnection agreements.

This document identifies opportunities for DER related process improvements and addresses potential reliability risks, promotes good utility interconnection practices necessary for BPS reliability, and promulgates information on how DER can enhance reliable BPS operation at the Transmission Distribution interface by providing essential reliability services. In addition, during the development of this document, a review of existing DER related documents was performed and NPCC is working with

⁵ <https://www.cpuc.ca.gov/Rule21/> Electric Rule 21 is a tariff that describes the interconnection, operating and metering requirements for generation facilities to be connected to a California utility's distribution system. The tariff provides customers wishing to install generating or storage facilities on their premises with access to the electric grid while protecting the safety and reliability of the distribution and transmission systems at the local and system levels.

the NY Interconnection Technical Working Group (ITWG) as well as the Joint Utilities group of NY to align processes where possible. As other related groups and endeavors are identified within the Region, NPCC will monitor and review their activities going forward and will coordinate with the NPCC Areas and its Members, as necessary.

Reliably and securely integrating DER into the electric system requires a comprehensive multi-pronged approach utilizing perspectives from different disciplines. There needs to be balance between DER performance requirements addressing distribution and BPS considerations, which are sometimes in opposition. DER design, modeling, planning, and relay coordination require consideration of jurisdictional issues. The importance of Members working with their respective national, state, and provincial regulatory authorities to help them understand the consequences of and the development of effective DER interconnection requirements is critical. While there may be some broad universal guidelines, the details of effective DER interconnection requirements should be reconciled with the characteristics of the system where the interconnection is taking place. [Appendix B](#) of this document provides a comparison of NPCC's Area requirements, at the time of the Version 1 writing, to help identify opportunities for guidance.

Many, if not most, of the current DER being deployed is theoretically capable of bringing several enhancements to reliability, provided that there are sufficient design specifications and interconnection requirements to implement the benefits. Inverter based DER may use fast, programmable responses to provide benefits to reliability if properly configured and coordinated with the host utility. Coordination must consider effects both on the distribution system and the BPS. The sections later in this document address DER impact on the BPS including aspects of:

- Displacement of conventional generation and the resulting decrease in grid strength and availability of Essential Reliability Services
- Planning model uncertainty
- Operational visibility
- Simultaneous DER generation loss during disturbances
- Angular stability impacts
- Voltage stability
- Frequency stability
- Inadvertent islands
- Transmission system effective grounding
- Over-generation
- System restoration
- GMD vulnerability
- DER capacity forecasting
- Resource adequacy

While DER presents opportunities to enhance reliability, they also introduce challenges at the Transmission Distribution interface if not deployed correctly. Interoperability with the transmission system is not solely determined at the point of interconnection. Visibility and a level of controllability of DER is essential for transmission operators to maintain situational awareness for reliable operation of the BPS, and for short-term forecasting. Additionally, characteristics of DER such as capacity, intermittent production, location, protection settings, and other parameters must be known for long-term operational performance forecasting and system planning to ensure BPS reliability is maintained. Additionally, the local distribution utility overseeing the interconnection of DER needs to be able to ensure that the DER doesn't cause safety issues for distribution line workers, adverse impact on distribution system equipment, or degrade customer power quality.

Presently there are limited study tools in general use to perform fully integrated studies of transmission and distribution which would allow both systems to be modeled and studied (in steady-state and dynamically) together⁶, although work is underway in this regard. In the shorter term, visibility of the variability of DER capacity could dramatically affect the quality of state estimator information, and methods of improving data and forecasting need to be explored. Some planners in the NPCC Region are moving to composite load models along with approximate DER representations for their simulations and planning activities.

In recognition of both the benefits and challenges associated with DER, the approach taken with this third version of the NPCC DER Guidance Document is to continue to collect interconnection related information within the NPCC Region as well as in other areas of the NERC Electric Reliability Organization (ERO) Enterprise. There are some specific situations where opportunity exists to ensure better coordination across the NPCC Region. These practices are supplemented this with information derived from other sources such as the NERC System Planning Impacts of Distributed Energy Resources (SPIDER) Working Group. The intent of this document is to identify any emerging reliability issues, provide general guidance and information where possible, and offer support to NERC and others North America wide to promote reliable interconnection and operation practices for DER. It is also recognized that DER may not be located optimally and/or in areas where deliverability to load may not be ideal. In this respect any specific information in this document must be considered in conjunction with the requirements of the interconnecting distribution utility.

NPCC DER Impact Reporting

In order to ensure the reliability and resilience of the interconnected BPS in Northeastern North America as DER, both aggregated and single installations, continue to proliferate throughout the distribution systems within the NPCC Region, it is important to have a regional DER impact reporting mechanism. The NPCC Regional Standard Committee (RSC) created an impact reporting form and process that allows entities to report DER impacts and to seek guidance regarding emerging issues and reliability risks that

⁶ The U.S. Department of Energy Argonne National Laboratory has a project underway to develop a tool that would Co-simulate Transmission and Distribution systems. The tool being developed will utilize Siemen's Power System Simulator "PSS®E" transmission system analysis tool with EPRI's open sourced distribution system smart grid tool "OpenDSS"([Smart Grid Simulation Tool](#)) using a Python interface. A detailed presentation on this project may be found in the October 2019 NPCC DER Forum meeting materials on NPCC's website.

affect or could affect the reliable performance of the BPS (see [Appendix A](#)). The Word version of the form also is available on the NPCC website at:

[BES Impact Reporting Form](#)

Impact reporting and its associated process provide an orderly mechanism for NPCC to review reliability impacts submitted. A Report will initiate a collaborative review by the Reliability Coordinating Committee and the Regional Standards Committee.

DER BPS Impact Considerations

NPCC's Regional Standards Committee (RSC) and Task Forces (i.e. Task Force on System Studies) reviews of DER as it pertains to the NPCC Region's BPS performance have identified several areas which, going forward, may warrant further and continual monitoring and analysis. NPCC has identified the following items that should be carefully considered as DER levels (total MWs) increase.

- DER performance with respect to voltage and frequency ride through
- DER ability to provide regulation and reserves
- DER dispatch and controllability
- DER availability, quality of forecasting, and verification
- Observability and situational awareness of DER, and the importance of implementing Advanced Metering Infrastructure (AMI) if telemetry is not deployed
- DER impacts on Underfrequency Load Shed programs
- Impacts of DER on System Restoration and Black Start Plans

Although DER markets, both wholesale and dual participation models, are not the focus of this document, due consideration should be given to their structure. Market rules that allow aggregation also vary across the NPCC Region. Within the US areas of NPCC, the recent FERC Order 2222 may have a profound impact on DER aggregation in the near future. Some Areas allow injection of the aggregation across their market area while other Areas require specific aggregations to be injected nearest to a transmission node. DER are capable of providing ancillary services that are necessary to support reliability, if there are appropriate market mechanisms and incentives that allow and encourage them to do so. In the U.S., FERC Order 2222 mandates that tariffs shall allow aggregations of DER to participate in the organized capacity, energy, and ancillary services markets run by regional grid operators. Wide-area aggregation and injection may create challenges for the system planners and operators as well as raise deliverability and operations concerns.

DER Characteristics Relevant to BPS

To understand the impacts of DER it is first necessary to define their unique characteristics. The various types of DER and the power conversion equipment (i.e., inverters, generators) used with DER have performance characteristics that shape their BPS impacts. A summary of the salient characteristics are provided in this section.

Synchronous Generators

Synchronous generators are commonly used in a number of DER applications, including reciprocating engine and small hydro generators. Engines may be fueled by natural, bio-, or waste gas, or infrequently diesel fuel. Engine-generators may be solely for electric power production, or combined with waste heat recovery for cogeneration or tri-gen (electric power, heating, and cooling) applications.

The fundamental characteristics of small synchronous generators are substantially similar to those of large BPS generating units, albeit with somewhat different per-unit parameters and less sophisticated excitation systems. Small generator per-unit impedances may be less than the typical range of large generators, and the inertia constants of engine generators can be quite small ($H < 1$ is not uncommon).

Synchronous generators behave as voltage sources, and are not dependent on the strength of the grid to maintain normal operation. When the grid is weak, combined with the low inertias of most DER synchronous generating units, there is vulnerability to transient instability due to faults on the transmission system as well as in the distribution system.

Induction Generators

Induction generators are sometimes used for engine-driven and small hydro generation. They have also been used in some types of micro-turbines. Prior to approximately 2010, induction generators were used in many large-scale wind turbines.

Induction generators must be provided with an external source of reactive power in order to continuously operate and they cannot directly regulate voltage like a synchronous generator. Induction generators are often combined with switched capacitor banks in order to compensate their variable reactive power demand. When there is a fault, induction generators initially supply a fault current equivalent to that of a similar-sized synchronous generator, but this current contribution decreases as the induction generator's rotor flux decays over a few cycles. When isolated with an excessive amount of capacitance, induction generators are vulnerable to a phenomenon called "self excitation" which can result in very high overvoltages.

Induction generators, alone, cannot meet the requirements of IEEE 1547-2018, and need to be combined with a variable reactive power source, such as a STATCOM, in order to achieve compliance with both the reactive power and voltage ride-through requirements. As IEEE 1547-2018 is adopted by utilities and jurisdictions, it is likely that application of induction generator technology for new DER applications will diminish. Where they continue to be applied, the performance of the DER facility will then be shaped by a combination of the induction generator and the supplementing dynamic reactive device (e.g., STATCOM).

Inverters

A power inverter, or inverter, is a power electronic device or circuitry that converts direct current (DC) to alternating current (AC). The inverter itself does not produce active power; its active power is provided by the DC source. In the case of battery energy storage applications, the interfacing electronic device is more correctly termed as a "converter" because the same device is used to convert ac power to dc in order to charge the battery (rectifier operation) as is used to invert dc to ac when the battery is discharged.

Inverters are capable of injecting and absorbing reactive power. A STATCOM, which may be used to supplement other DER devices such as induction generators by providing a dynamically-controlled reactive power source, is fundamentally an inverter without a dc power source. Thus a STATCOM cannot transfer active power except for the absorption of a small amount of active power to cover its losses.

Virtually all inverters used for DER applications are current-regulated voltage-source inverters/converters. These use pulse-width modulation to synthesize an ac voltage waveform of the magnitude and phase angle necessary to create the desired active and reactive power flow through the inverter's output impedance. These inverters use transistors that are extremely vulnerable to damage from overcurrent of even very short duration (sub-cycle). Therefore, very fast-response controls are used to regulate the current magnitude, creating a virtual current source. As a result, an inverter will inject a current that is little more than the rated value when subjected to a fault. Inverters are capable of injecting or absorbing reactive power, up to limits defined by the inverter's thermal current limits and ability to synthesize the appropriate ac voltage to create the reactive power flow.

Inverters operating in this manner, as a controlled current source, are said to operate in a grid-following mode. Such inverters cannot properly operate without an external source of ac voltage. In a grid-following inverter, the terminal voltage waveform is sensed by a control algorithm called a phase-locked loop that is used as a reference for the phase angle of the injected current. External system (grid) impedance makes the sensed terminal voltage magnitude and phase angle dependent on in-phase and out-of-phase components of the injected current. Thus there is a closed loop interaction that can become unstable if the impedance is too large; i.e., the system to which the inverter or aggregation of inverters is connected is too weak.

Grid-following inverters, in addition to their vulnerability to control instability when the grid is too weak, also cannot provide their owners with a source of backup power and cannot provide certain grid services such as black-start capability. In very recent years, an alternative inverter control mode is beginning to emerge, called a grid-forming inverter. These inverters create a voltage source that is maintained in synchronism with the grid by either emulating the inertial characteristics of a synchronous generator, or by a droop-control method. The inherent susceptibility of inverters to near-instantaneous over-current failure of transistors constrains operation in a grid-forming mode. Whereas a synchronous generator may deliver several times rated current during faults and during post-fault angle swings without suffering damage due to the thermal mass of the generator, it is generally not economically feasible to design inverters with such short-term to mid-term overcurrent capability. Therefore, a grid forming inverter may need to switch to a current-limiting mode during system disturbances. Unlike a generator, whose characteristics are defined by physics and performance differs little from design to design, inverter behavior is totally defined by the creativity of the control designer. There are wide variations in the performance of grid-forming inverters, particularly in the response to large-scale grid disturbances such as faults.

A grid-forming inverter must have a controllable dc input power. For example, PV inverters are typically operated at their maximum available power. Any temporary deviation between the phase angles of the voltage created by a grid-forming inverter and the grid voltage necessitates a change in active (real) power. If an inverter is already operating at its maximum dc input power, it cannot accommodate an

angle deviation where the inverter's voltage phase angle increases its lead over the grid voltage. Therefore, grid-forming inverters generally require some form of energy storage on the dc side. Alternatively, the dc source could be operated sub-optimally (pre-curtailed) such that there is always active power headroom, but this is generally uneconomical. The energy storage used with a grid-forming inverter can be in the form of batteries or super-capacitors.

Doubly-Fed Generators

Doubly-fed generators (DFG), also known as doubly-fed induction generators, use an ac-dc-ac power electronic converter to couple the machine's rotor with the grid ac system. This converter provides a variable-frequency "excitation" to the rotor, creating an apparent rotation of the rotor's magnetic field relative to the physical rotation of the rotor. By providing the correct frequency and phase sequence to the rotor, the resultant magnetic field rotates at 60 Hz synchronous speed relative to the grid-connected stator. This allows wide variability in the rotor mechanical speed while producing 60 Hz output.

The operational characteristics of a DFG resemble that of an inverter during normal operation and for most fault situations because the controls regulate output to a constant current or constant power, except during severe faults. This current regulation is not as fast as that of a typical inverter, but is sufficiently fast that the machine behaves like a current source for most situations. Severe faults can require the rotor to be short-circuited by electronic switches in order to protect the power converter. With the rotor shorted ("crowbarred"), the machine's performance is similar to that of an induction generator.

DFGs are widely used in large-scale wind turbines due to the aerodynamic advantages provided by variable-speed operation. However, large-scale wind turbines are usually connected to the grid at the transmission level, and thus are rarely used as DER. DFGs might also be used in certain hydro-electric DER applications.

Photovoltaic (PV) DER

The large majority of DER being installed presently in most NPCC areas is PV. PV generation exclusively uses inverters, which vary in individual unit size from a few hundred watts (micro-inverters) to large multi-MW central station inverters. Distribution-connected PV installations vary from a few kW for a typical residential rooftop application up to several MW for utility-scale facilities. Because distribution substations tend to be located in or near built-up areas where land is often not available for large solar arrays, utility-scale PV facilities are often located on load-serving distribution feeders at locations quite distant from the substation.⁷

Due to shadowing produced by moving clouds, the output of an individual PV panel can be highly variable on a short-term basis. Geospatial diversity of different panels within an array, and for different installations on a distribution system, tends to smooth output. This short-term variability of PV output can create issues such as voltage variations on distribution systems. Short-term PV variability due to cloud shadowing, however, is almost always inconsequential at the BPS level as the output of any one

⁷ Much of the material generated by the NERC SPIDER Working Group states or infers that utility-scale DER (U-DER) is normally located close to a distribution substation or is connected to a dedicated distribution feeder that serves no load customers. This guidance differs from the reality in most NPCC utilities.

distribution-connected site is insignificant, and the aggregation of many sites dispersed over a wide geographic area is greatly smoothed.

Of greater concern at the BPS level is the diurnal variation of PV output. Depending on PV panel orientation, whether panel tracking is used, and prevailing weather conditions, PV output tends to be peak at solar noon (near 12 noon at the center of a time zone during standard time, and 1 pm where daylight saving time is used) and tends to decrease rapidly in the late afternoon to early evening when load tends to increase. Dispatchable generation resources are dispatched to meet the net load, and the combination of load with the output of PV can create a double-hump net load curve often called a “duck curve” due to its shape. With high PV penetration, the net load rises in the morning prior to substantial PV output and then decreases to a low value during midday when PV output is high. In the late afternoon, the combination of decreasing PV and increasing load can create very high ramp rates in the dispatch of generation. Many conventional resources have difficulty following fast ramp rates. In regions with high PV penetration, this has had profound impact on the commitment and dispatch of generation, sometimes requiring commitment of higher-cost units capable of meeting ramping requirements (e.g., single-cycle gas turbines) in order to maintain grid security.

Distribution-Connected Wind Generation

Because wind speeds increase substantially with height above ground, wind generation is usually only economically viable where large-scale wind turbines (multi-MW) are used. There is a very large mobilization cost to erect a wind turbine (e.g., costs to transport and assemble a 400’ crane on site) that makes wind facilities having only a few wind turbines not economically attractive. Wind plants consisting of many large-scale turbines have too great a capacity for typical distribution systems to accommodate. Therefore, DER in the form of wind generation is infrequently encountered except where social policies have strongly incented DER wind generation, such as in Ontario.

Energy Storage Systems

Battery storage technology is undergoing a rapid evolution from Lead Acid to Absorbent Glass Mat to Li-Ion due to the expanding application of batteries to transportation and other sectors. Li-Ion batteries have been and continue to be deployed in a wide range of electric energy-storage applications, ranging from energy-type batteries of a few kilowatt-hours in residential systems with rooftop photovoltaic arrays to multi-megawatt containerized batteries for the provision of grid ancillary services. The Energy Storage Association (ESA) anticipates at least 35 GW of new energy storage will be deployed in the United States by 2025. Policymakers see energy storage as a key element working toward the goal of a carbon-free grid, and are incenting the installation of energy storage at both the distribution and transmission levels.

There are a wide variety of potential use cases and applications for energy storage systems (ESS) connected to distribution systems, including benefits to an individual power consumer, contracted benefits to the utility, as well as participation in energy and ancillary service markets. Retail use cases include:

- Peak load reduction. This can be particularly valuable to commercial customers subject to a power demand charge tariff.

- Advantageous use of time-of-use rate tariffs, by avoidance or decrease of utility power during high-cost periods by energy storage discharge, and recharging during low rate periods.
- Backup power source. (Note that a grid-forming inverter or dual-mode invertercapable of operating isolated from the grid is necessary to apply this use case.)

Where distribution-connected ESS can participate in the market, either directly or via an aggregator, use cases include:

- Energy price arbitrage.
- Frequency regulation services
- Capacity reserves

Increasingly, utilities are turning toward energy storage as a non-wire alternative to reinforcement of transmission and distribution infrastructure as either a utility-owned asset or as a service contracted from a non-utility owner. Where overhead transmission or distribution lines or power transformers are the constrained network branch, ESS can be an effective alternative to new transmission or distribution assets.

Because energy storage has round-trip energy loss, use of ESS as a non-wires alternative increases the energy that must be delivered through the constrained network branch. Unlike overhead power lines, which have a short thermal time constant on the order of minutes, underground cables have thermal time constants on the order of days. Discharge of an ESS during peak hours with recharge during off-peak hours results in a more constant load but with an increased average value due to the storage losses. As a result, the cable loading, as measured by the peak cable temperature, is not reduced to the same extent that the peak load magnitude is reduced. This exposes a pitfall in typical planning practices which are based on peak loading of network elements. Another way to look at this is that peak cable ampacity is a function of the shape (loss factor) of the load cycle. A flatter load cycle results in a decreased peak ampacity. Thus the leveling of the load cycle by ESS can decrease a cable's peak loadability to almost the same extent to which the peak load is reduced.

Hybrid Resources

NPCC is also observing marked increases in Hybrid Resources which are combinations of multiple technologies that are physically and electronically controlled by the Hybrid Owner/Operator behind the point of interconnection ("POI") and offered to the grid as a single resource at that POI. Distribution hybrid resources usually involve energy storage at a PV site. It optimizes the use of DER and enables normally clipped energy (power beyond the transfer limits of the power system, or unneeded by the BPS) to be stored on-site and released in the future.

Hybrid resources can either be dc-coupled or ac-coupled. A dc-coupled hybrid is one where the energy storage device (typically a battery) shares the same inverter as the PV resource. This can decrease the capital costs of power conversion equipment and reduce conversion losses. A dc-to-dc converter (effectively a dc "transformer") is needed to interface the battery to the dc bus because the PV array and the battery cannot optimally operate at the same dc voltage for all conditions. A common PV

design practice is to install more PV array capacity than the inverter rating⁸ because the PV array output is at its maximum output for only a small fraction of the time. By doing so, the overall amount of energy produced, relative to the inverter capacity, is increased. With a dc-coupled hybrid arrangement, the array output in excess of the inverter capacity can be captured by the energy storage for release at another time when there is inverter capacity available.

An ac-coupled hybrid uses separate converters for the battery and the PV array. This allows the peak output of the facility to be the sum of the PV and battery outputs which can be economically beneficial under some conditions. This also simplifies equipment procurement and allows flexibility in the physical location of the energy storage.

Variations in PV output can cause distribution voltage variations, and sometimes PV developers are required to cover the high expense of reconductoring distribution feeders to mitigate the voltage impacts. Energy storage, used to levelize the PV plant output, can mitigate this voltage variation but more often the use of inverter reactive power capability is a more efficient approach to voltage regulation issues.

For retail owners of hybrid systems, it is possible to make their facility “non-exporting”. PV output in excess of contemporaneous demand of the customer’s load is absorbed into the energy storage, and the storage is discharged when customer load exceeds PV output. This arrangement can sometimes avoid certain DER interconnection technical requirements.

BPS Planning and Operational Performance Impacts

At low penetration levels, DER has little impact on the BPS and thus does not pose any substantive risk to BPS reliability. However, the rapid growth of DER penetration in many areas presents new challenges to the planning, design, and operation of the BPS. The major impacts of DER on the BPS are summarized in this section.

Displacement of Conventional Generation

Increased DER penetration decreases the net load to which transmission-connected resources, primarily conventional synchronous generators, are committed and dispatched. The large majority of DER in most areas is inverter based using grid-following controls. Grid-following inverters, as regulated current sources, present an extremely large (ideally infinite) effective impedance to the grid. Thus, the displacement of conventional synchronous generation by inverter-based DER will reduce system strength.

Decreased system strength means decreased short-circuit current levels, which can compromise the effectiveness of conventional protective relaying schemes used in the BPS. Decreased strength also results in greater voltage sensitivity to loading changes, more severe harmonic resonance issues, and greater potential for control instability of inverter-based resources at both the transmission and distribution levels.

⁸ The ratio of array capacity to inverter capacity is called the dc/ac ratio. Currently, the low price of PV array capacity has pushed typical dc/ac ratios to the range of 1.2 to 1.4.

Displacement of conventional BPS generation by DER also removes resources that currently provide essential reliability services, including inertia, voltage regulation, frequency regulation

Planning Model Uncertainty

Conventional BPS generation is represented explicitly in planning models, based on the actual characteristics of the generation equipment and as confirmed by testing in accordance with NERC MOD-026-1. In contrast, individual DERs, other than very large facilities, are not feasibly modeled on an individual basis. Instead, aggregate models are necessary. Unlike large synchronous generators whose dynamic performance characteristics are defined by physics and vary to only a limited extent between units, inverter-based DER performance is defined primarily by control algorithms, which can vary widely by make, model, and vintage. These performance characteristics are generally poorly defined, even on an individual DER basis. DER performance required of new inverters will create an even wider disparity in behavior between legacy DER designed in conformance with the prior IEEE 1547-2003 and inverters designed for conformance with IEEE 1547-2018 and certified to UL-1741 SB. Planning models based on aggregate DER representations must necessarily combine the behaviors of many disparate, poorly defined DER characteristics, with typically incomplete information regarding even the mix of various DER types. Thus, there is considerable uncertainty in the accuracy of DER models used in BPS planning studies; a degree of uncertainty that is at least as large as the uncertainty involved in modeling aggregate load behavior.

Operational Visibility

BPS generation plants are under the dispatch control of the RTO/ISO, and their active and reactive power output is continually monitored via SCADA and EMS. Except for very large facilities, DER output today is typically unmonitored and non-dispatchable. Power delivered into the distribution systems, as monitored by SCADA, is the net load; actual load minus DER generation. System operators do not have direct knowledge therefore of the true level of system load, nor of the real-time output of DER. Status of DER is also not available.

This lack of operational visibility can adversely impact BPS security. For example, if the majority of DER output is from PV (which is typically the case in most NPCC areas), changing weather conditions can rapidly decrease the DER power output leaving only the remaining system resources to supply the full system load. Additional operating reserves may be needed to protect against this possibility, but determination of the amount of reserves is challenged by incomplete operational visibility.

DER Aggregation

FERC Order 2222 requires RTOs/ISOs in the US to allow aggregators of DER to participate in wholesale energy, capacity, and ancillary services markets. Although individual DER of sufficient size could previously participate in wholesale markets, aggregation greatly increases the amount of DER capacity that can potentially participate in practice. While this might create significant impact on distribution systems, and may have an economic impact on markets, the impacts of DER wholesale market participation on bulk system security are quite limited.

The majority of present DER capacity is the form of non-dispatchable variable energy resources, primarily solar PV. While these resources could potentially be bid into the capacity and energy markets, this market participation is unlikely to change the timing and amount of power output from these DER.

Economic factors incent these resources to generate to the full extent of their natural resource (e.g., solar irradiance) at all times. Any participation of these resources in energy markets is likely to be purely an economic transaction.

The participation of variable energy DER resources (i.e., PV) in the ancillary services markets is likely to be very limited. While it is technically feasible for these resources to offer down-regulation frequency regulation service or “spill” potential generation in order to maintain sufficient power margin to offer up-regulation, the bid price of such services would necessarily be quite high in order to compensate for the opportunity cost. Other resources, including energy storage DER, will be able to offer regulation service at a lower cost. It is also unlikely that variable energy DER will have any significant participation in operating reserve markets, due to the same economic reasons.

There is presently a rapid increase in the deployment of energy storage DER (ES-DER). These are likely to have much greater participation in the wholesale markets due to their inherent dispatchability. ES may engage in arbitrage activity in the energy market, as well as frequency regulation and operating reserve ancillary service markets. Arbitrage, particularly where ES-DER are located near loads, inherently tends to levelize BPS loading. Thus adverse congestion impacts should rarely be an issue. The non-diverse rapid variation of power output of ES-DER providing frequency regulation service can be problematic for the distribution operator, potentially causing power quality (flicker), voltage violation, and excessive tap changer and switched shunt operations in the distribution system. From the bulk power system viewpoint, expanded availability of creditable capacity and ancillary services provided by aggregated DER is likely to be beneficial to BPS security. However, due attention needs to be paid by the RTOs/ISOs in determining the participation rules for the aggregated DER participation in capacity and operating reserve markets to confidently ensure deliverability, including the possible impact of distribution system limitations, and reliability. The tendency for DER to be located near loads generally makes deliverability less of a concern in most cases, however. Verification of aggregated DER performance can be challenging. Distribution technical limitations, such as voltage issues, could constrain ES-DER from providing services or delivering capacity when needed, and such limitations need to be evaluated when market participation is considered. Duration of ES power contribution (i.e., energy) must be considered in defining DER-ES participation in capacity and operating reserve markets, in the same way as transmission-connected ES.

Participation of DER of any type in voltage support ancillary service markets seems infeasible in most cases. Distribution systems typically use on-load tap changers in the primary substation transformers, feeder voltage regulators, and switched shunts to manage the distribution system voltage. These tend to decouple the transmission and distribution system voltages. Therefore, voltage at the DER location has no relationship to the transmission system voltage state, and is primarily defined by local distribution power flow conditions.

As stated above, visibility of DER to transmission system operators is often quite limited, particularly for smaller DER. Aggregators will necessarily have some form of telemetry in order to control the aggregated DER and monitor the output. Thus it may be possible data interoperability between the aggregator and the TSO may be a simpler and less costly way to achieve improved operational visibility of DER that would otherwise not be directly telemetered by the utility or TSO.

Loss of Generation During Disturbances

Transmission system voltage and frequency disturbances are seen at the terminals of DERs over a wide area⁹. If DER were to trip as a result of the disturbance, it is possible for a large amount of DER generating output to be lost simultaneously. This has the potential to significantly aggravate the BPS disturbance and can endanger system security.

NERC and NPCC have criteria for resource and transmission planning. For transmission, criteria require transmission planners to simulate different transmission system events and ensure the transmission system remains reliable by meeting performance characteristics for these events. If the transmission system does not remain reliable, the planners are required to identify remediation, including upgrades or expansions of the transmission system. One aspect of the simulation is to account for the loss of generation resources. If a significant amount of DER trips or ceases to inject current for the simulated transmission event, the transmission system could become unreliable for that event and require remediation. This can occur in several scenarios such as a peak load day with maximum output from DER like solar PV or a light load spring day where PV solar and small hydro make up a significant percentage of the generation. The industry is now in the process of promoting ride-through via several different standards initiatives which NPCC is tracking through its DER Forum.

This issue became more widely recognized after some recent events in the WECC system where normally inconsequential transmission faults have resulted in significant disturbance of the grid frequency. Although not involving DER in these particular cases, transmission-connected PV plants installed and protected using distribution-focused standards (IEEE 1547-2003 and UL-1741) were identified as a root cause. NERC developed three NERC Disturbance Reports related to system disturbances in California which resulted in significant inverter-based resource interruptions. The reports may be found on NERC's Major Events Analysis Reports page:

<https://www.nerc.com/pa/rrm/ea/Pages/Major-Event-Reports.aspx>.

The original IEEE 1547-2003 was not developed with BPS security in mind. There were no requirements for DER to remain on line for any disturbance whatsoever, but there were mandatory requirements to trip for voltage and frequency deviations that can be considered relatively minor. This reflected a common opinion, which persists today in the utility distribution community, that DER is a non-critical resource that should be tripped off line for even the slightest disturbance to avoid distribution system issues such as islanding, loss of grounding, and protection mis-coordination. Typically, past practice has been that DER protection requirements were determined by distribution service providers without consultation with transmission planners. With the increasing level of DER penetration, this singular focus on distribution concerns could pose a threat to the reliability and security of the BPS.

Angular Stability

The large majority of DER is inverter-interfaced and thus does not have inertial characteristics to participate directly in angular swings following faults and other disturbances. However, displacement of

⁹ Transmission system positive sequence voltage changes appear as changes of approximately equal magnitude at the distribution level due to the radial connection of distribution systems to the transmission system. Voltage changes caused by unbalanced transmission faults are modified by typical winding connection of distribution substation transformers. Except for short-term transient variations, frequency is uniform over an entire transmission interconnection unless the transmission system has broken into islands.

conventional BPS-connected generators from commitment and dispatch by DER power output inevitably creates some impact on the angular (transient) stability of the BPS. Whether this impact is positive or negative depends on the specific system, such as location of the DER relative to the conventional resources. Proper evaluation of this impact requires appropriate inclusion of DER in stability modeling, rather than simply “netting out” the DER output offset of customer load.

The relatively small portion of DER consisting of synchronous generators will experience rotor angle swings as a result of transmission system faults and other disturbances. This may result in these generators going out of synchronism and tripping. This instability is generally not of significance to the BPS due to the low penetration of this type of DER.

Voltage Stability

Almost all inverter-based DER installed today operates in a grid-following mode which provides no “stiffness” to the system. Most DERs are also presently operated in a fixed power factor mode (typically, unity), including DER which have voltage regulation capability, to avoid adverse interactions with distribution system voltage regulation. Displacement of conventional BPS generation by DER output both increases the BPS’s voltage sensitivity by decreasing grid strength, and removes sources of dynamic regulation of the BPS voltage. Thus, increased DER penetration creates increased risk of BPS voltage instability and voltage collapse.

Frequency Stability

Frequency support is provided through the combined interactions of synchronous inertia and frequency response. Working in a coordinated way, these characteristics and services arrest the decline in frequency after a disturbance and eventually return the frequency to the desired level. As increased levels of DER are introduced to the system, synchronous inertia will be displaced, which may have an impact on the frequency response performance of the system.

Under-frequency load shedding (UFLS) is implemented to restore power system frequency stability if system frequency drops below the UFLS operational set point. Significant deviations in system frequency typically occur during major disturbances such as a loss of generation or events in excess of design contingencies used for planning purposes. UFLS is considered the “safety net” for the BPS and a last resort automatic operation designed to stabilize BPS islands for a generation deficiency. Various fractions of load are shed in multiple stages, up to about 31% of peak net load¹⁰, in order to stabilize frequency. UFLS is primarily installed on distribution feeders, where DER is increasingly being deployed. When a distribution feeder is tripped by UFLS, the output of any DER connected to the feeders will be lost. This results in less net load reduction than envisioned when the UFLS scheme was devised. There is an increasing number of distribution feeders in NPCC that have more DER capacity than load, producing reverse power flow during certain hours, and thus any UFLS implemented on such feeders will have a result contrary to the intention of UFLS.

¹⁰ Peak net load shall be calculated as an average of the peak net load from the previous 3 years, excluding the current year. See NPCC’s Regional Standard for further details on UFLS requirements, PRC-006-NPCC-2 [Automatic Underfrequency Load Shedding](#)

Inadvertent Islands

Inadvertent islands may be formed when a portion of the transmission or distribution system is isolated from the remainder of the grid and there is sufficient DER capacity installed to maintain energization of the isolated sub-system (island). Although an entire distribution substation along with some transmission assets could become islanded in a very high DER penetration scenario, islanding is primarily a distribution system concern.

IEEE 1547 (both 2003 and 2018 versions) require DER to detect islands and cease to energize within two seconds. DER manufacturers employ a number of different schemes to perform this detection. The most common islanding detection algorithms DER intentionally destabilize islanded systems in order to force voltage or frequency tripping. There is some concern that, at high regional DER penetration, these functions may also have adverse impact on the dynamic stability of the bulk system. This potential issue is in need of research to define its extent and severity.

Transmission System Effective Grounding

Primary distribution substation transformers typically have an ungrounded winding (delta or ungrounded-wye) on the transmission or sub-transmission side. Such windings present an open circuit in the zero sequence and thus cannot provide a ground source. The ground sources in a transmission system are typically provided by power plant generator step-up (GSU) transformers, and transmission autotransformers having delta tertiaries. Isolation of a primary distribution substation on the transmission side, such as by opening of the remote end of a radial transmission line supplying the substation, results in the substation becoming disconnected from the source of grounding. If sufficient DER capacity is connected to the distribution system to maintain greater than 0.8 p.u. voltage, and one phase on the transmission side remains faulted to ground, there can be a voltage-to-ground on the unfaulted phases that exceeds the criterion for effective grounding. The most vulnerable substation equipment for such temporary overvoltages is the metal-oxide varistor surge arresters protecting the transformer. It should be noted that this overvoltage condition is not observable at the DER locations on the distribution side. Failure of a surge arrester is not of immediate consequence to the transmission system unless the line supplying the substation is reclosed. The reclosing into a pre-failed surge arrester will create a fault on a second phase, and thus a single phase transmission fault may be followed by a double-phase-to-ground fault after reclosing. Typically, the transmission connection to distribution substations is at the sub-transmission or lower transmission voltage level where faults tend to have only local impact. Therefore, the issue of DER impacts on transmission effective grounding is only remotely of relevance to BPS reliability. The impacts of DER on effective grounding within the distribution system are of no consequence to the BPS and will not be addressed in this document.

Over-Generation

With high DER penetration, the possibility exists of more DER output than is needed by the system, considering the minimum conventional BPS resources needed to be maintained on line to maintain BPS security. This is most likely to occur during low-load periods when DER output is high, such as in the springtime shoulder season. This situation has occurred in the state of California when the system operator runs out of load to absorb the available generation.

Addressing this over-generation issue is complicated by the fact that most DER is not under direct, or even indirect, control of the BPS system operator. Except for larger DER installations, there is rarely a SCADA interconnection that allows a system operator to curtail (limit) DER generation. Some utility-scale DER facilities that do not have direct BPS system operator control implemented are remotely controlled by a non-utility entity contracted or owned by the DER owner. This remote control facility may be in another state or even a different country, and execution of a curtailment order by the BPS operator may require inefficient means such as telephone. Small DER, including residential rooftop PV, typically operates completely autonomously, and there may be no one that can be contacted to implement curtailment in a timely manner.

System Restoration

If a DER is tripped as a result of the operation of a protective device, the DER is required by IEEE 1547 to remain off-line until the utility's service voltage and frequency have recovered to acceptable voltage and frequency limits for a specified period of time. IEEE 1547-2003 in clause 4.2.6 allows an adjustable restart delay or a fixed delay of 5 minutes. A five-minute delay is the most commonly specified by distribution system operators.

For a severe transmission fault that causes DER tripping over a wide region, the DER power resource will not be available during this delay time but then the power may abruptly reappear after the programmed delay. BPS resources are typically dispatched within transmission constraints according to the net load, and thus with high DER penetration the transmission system may need to be operated at short-term overload levels during this delay.

Resumption of DER output after the required delay may greatly complicate system restoration in situations where the BPS has been disconnected into islands. The abrupt drop in net load may compound the cold-load pickup phenomenon that must also be addressed during restoration. Conventional generation units operating near their maximum power capability during initial restoration of a BPS island could potentially be forced below their minimum power levels by abrupt resumption of DER generation within the island after the delay.

System short-circuit strength in isolated BPS islands during restoration will be much less than in the intact BPS. It is possible with high penetration of grid-following inverter DER that the ratio of DER capacity to available short-circuit strength may be inadequate for stable operation of the inverters. Control instability may result, and it should be noted that this form of instability cannot be simulated or investigated using conventional phasor-based dynamic analysis tools that are commonly used in transmission planning.

GMD Vulnerability

Flow of geomagnetically-induced current (GIC) during a geomagnetic disturbance (GMD) requires substantial distance between grounding points in order for the electrical field to integrate to sufficient magnitude to drive significant GIC through system resistances. Therefore, GMD is not of direct impact to DER as distribution systems do not have sufficient geographic extent for GIC to be induced, and the winding connection of distribution primary substation transformers blocks GIC from the transmission system from entering the distribution system.

High DER penetration may displace conventional generators from commitment, and thus leave the grid voltage and frequency more sensitive to the impacts of GMD on the BPS due to decreased system strength, decreased inertia, and less voltage and frequency regulation capability.

A GMD, however, can have indirect impact on DER that may potentially be of consequence to BPS security. GIC flow through BPS transformers create potentially extreme reactive power demands that can create long-duration system undervoltage conditions. Voltage below the normal operating voltage range will cause DER to trip and remain off line, depriving the BPS of their power contribution at a time when the BPS is unusually stressed.

GIC flow through the BPS also causes large amounts of harmonic current to be injected by saturated BPS transformers, creating unusual levels of voltage distortion. Many DER use rather unsophisticated algorithms for frequency measurement, such as the timing of voltage zero crossings, which are highly susceptible to false measurements due to severe harmonic distortion. The response of DER to such distortion is highly unpredictable as this situation is not a normal design consideration nor is this considered in DER certification testing.

Power Quality

In practice, DER-related power quality issues are exclusively distribution issues and have little to no impact or relevance to the bulk power system, or to power quality in other distribution systems. Therefore, this topic is not addressed in this document.

Resource Planning Impacts

Forecasting resource adequacy is an important system reliability planning function¹¹. The reporting of generation capability and related performance data is integral to this activity.

Forecasting Installed DER Capacity

Proper planning of system resources to meet net load in the future requires accurate forecasting of DER contribution as well as load demand. To determine DER power output contribution, it is first necessary to forecast the installed DER capacity by type.

Unlike load forecasting, for which the utility industry has substantial experience based on such techniques as econometric models, DER capacity depends on a number of factors that are difficult to predict, including:

- State and local policies and incentives, such as renewable portfolio standards, net metering tariffs, etc.
- National policies, including tax treatment of renewable energy investments.
- Cost of DER equipment, such as solar panels, inverters, etc.
- Availability of land for DER requiring dedicated space, such as utility-scale distribution-connected PV farms, and local zoning policies allowing utilization of available land.

¹¹ For background on resource adequacy metrics see: "[Resource Adequacy Metrics and their Applications](#)" prepared by the New York State Reliability Council.

The experience in most areas is that the actual rate of DER capacity growth has continually exceeded previous forecasts.

Resource Adequacy

Installed DER capacity alone is not sufficient information to determine resource adequacy. Most DER, such as PV, is variable in output and the correlation of DER output with the timing of system need is essential to the resource planning process. Even “base-load” DER, such as combined heat and power (CHP) installations and waste-gas fueled engines have periods of unavailability.

Unlike transmission-connected resources, for which hourly output and availability status data are directly available to the resource planner, DER output is generally not monitored presently by the system operators with the possible exception of certain larger utility-scale DER facilities. This complicates accurate calculation of the capacity contribution of DER.

Interconnection and Conformance Testing Standards

Interconnection requirements have substantial impact on the design and performance characteristics of DER equipment, such as inverters. It is infeasible for the manufacturers of such equipment to offer equipment customized to each and every utility’s individual requirements. Furthermore, the aggregate impact of DERs create impacts on the BPS that extend beyond individual utility systems. Therefore, national DER interconnection and testing standards are of fundamental importance.

IEEE 1547

IEEE 1547 is the *de facto* national DER interconnection standard in the US, and is specifically cited in the Energy Policy Act of 2005. The original version of this standard was published in 2003. At that time, DER penetration was deemed insignificant and DERs were not considered to be critical resources. To minimize potential for adverse distribution system impacts such as islanding and fault current contribution, IEEE 1547-2003 required DER to trip off line for relatively minor system disturbances and DER were prohibited from providing grid support such as voltage regulation. This standard was reaffirmed (renewed), without change, in 2008.

With increasing DER penetration, the industry came to realize that the provisions of this original version of IEEE 1547 were increasing the potential risks to the reliability of the BPS and obstructed DER from providing essential reliability and grid support services. The standard was amended by IEEE 1547A-2014 to allow DER voltage and frequency disturbance ride-through and for DER to optionally provide voltage regulation functionality.

At approximately the same time, a change of the IEEE Standards Association’s policies no longer allowed standards to be reaffirmed, but rather required that standards be re-developed on a periodic basis. A large working group was convened, with stakeholders from across the industry, to develop a new version of IEEE 1547 that addresses the many challenges brought about by the ever-increasing level of DER penetration. After several years of work, the new IEEE 1547 standard was published in 2018.

Compared to the sparse simplicity of the original 2003 version, IEEE 1547-2018 is far more complex and detailed. The new standard requires DER to have the capability of riding through severe voltage and

frequency disturbances as well as the capability to provide grid support services including reactive power, voltage regulation, and frequency response. Note that the standard requires only the capability of these functionalities; disturbance ride-through performance remains constrained by voltage and frequency trip functions that are defined by the Authority Governing Interconnection Requirements (AGIR; typically either the utility or a regulatory body), and deployment of grid support functions is at the discretion of the interconnecting utility. IEEE 1547-2018 was amended with minor changes to voltage ride-through and tripping requirements and parameters by IEEE 1547a-2020.

Some types of DER are inherently different than others with regard to their capability to ride through disturbances. Setting universal DER performance requirements based on the least common denominator results in the inability to capture the beneficial capabilities of the majority of DER. Alternatively, setting high requirements that are not practically achievable by some types of DER will effectively prohibit certain DER technologies that may offer a unique societal benefit (e.g, waste-methane engine generators). Rather than delving into non-technical policy issues (e.g., environmental) by assigning DER performance capability requirements by specific technologies, IEEE 1547-2018 instead defines three separate system disturbance performance categories, with the assignment of specific DER types and technologies to the categories left to the AGIR. The voltage and frequency disturbance performance categories are as follows:

- Category I is based on minimal BPS reliability needs and is reasonably attainable by all DER technologies that are in common usage today.
- Category II covers minimum BPS reliability needs, and coordinates with NERC Reliability Standard PRC-024-2, which was developed to avoid adverse tripping of BPS generators during system disturbances.
- Category III provides the longest duration and widest range (band) for voltage ride-through capabilities that are attainable by inverter-based systems where very high levels of DER penetration are expected or where momentary cessation requirements are seen as a desirable solution for coordinating with distribution system protection and safety. This category is intended to address DER integration issues like power quality and system overloads caused by DER tripping in the local Area Electric Power System and to provide increased BPS reliability by further reducing the potential loss of DER during bulk system events.

In addition, IEEE 1547-2018 also defines two separate performance categories (Category A and Category B) related to reactive power capability and control. A given DER type, technology, or application should be assigned by the AGIR to both a disturbance performance category (I, II, or III) and a reactive capability/control category (A or B).

Figure 1 shows an example assignment of disturbance performance categories.

Power Conversion	Prime Mover / Energy Source	Category
Inverter	Solar PV, Battery Energy Storage	Category III ¹ (amended)

	Wind	Category II
	Hydrogen Fuel Cell	Mutual Agreement
Synchronous generator	Bio-/landfill gas, fossil fuel, hydro, combined heat & power	Category I
Induction generator	Hydro	Mutual Agreement
¹ was Category II prior to Amendment		

*Figure 1: Example assignment of IEEE 1547 abnormal performance categories to various types of DERs.
Source: Provided courtesy of EPRI¹²*

IEEE 1547.1

IEEE Standard 1547.1 specifies the testing and verification of DER capabilities and performance relative to the technical requirements of the base IEEE 1547 standard. IEEE 1547.1-2005 was the testing companion of the original IEEE 1547-2003. More recently, IEEE 1547.1-2020 has been published as the testing and verification standard related to IEEE 1547-2018.

A major change in IEEE 1547-2018 is the requirement for large power-exporting DER¹³ to deliver their capabilities at the point of utility system connection (Point of Common Coupling, or PCC), rather than just at the terminals of the DER unit (Point of Connection, or POC). The original IEEE 1547-2003 was rather ambiguous on this, but the prevailing interpretation was that the original standard applied only to performance at the terminals of the power conversion or generation equipment. Therefore, factory or laboratory type-testing was deemed sufficient to provide reasonable expectation of compliance with the base standard in the field.

While consumer-grade DER (e.g., rooftop PV) has the POC as the Reference Point of Applicability (RPA) under and the new IEEE 1547-2018 and type testing is sufficient, utility-scale DER (e.g., PV farms) now have to provide the required capabilities at the PCC, which is typically at the distribution primary voltage level. Thus there is DER facility equipment between the DER units (i.e., inverters or generators) and the PCC that affect performance. For example, step-up transformers create reactive power losses that require either the inverters/generators to have extra reactive capability or other supplemental equipment (e.g., capacitor banks, STATCOMs, etc.) to meet the net reactive requirements at the PCC. Voltage drops due to the Impedances of this transformer also potentially impact disturbance ride-

¹² EPRI makes no warranty or representations, expressed or implied, with respect to the accuracy, completeness, or usefulness of the information contained in the Material. Additionally, EPRI assumes no liability with respect to the use of, or for damages resulting from the use of the Material.

¹³ IEEE 1547-2018 provides a somewhat complex set of criteria that define whether the Reference Point of Applicability (RPA) of the standard is the PCC or POC. In simple terms, the RPA is at the PCC unless the DER facility is not capable of, or is prevented from, exporting more than 500 kVA to the utility system.

through performance of the DER facility, relative to the standard's requirements that are applicable at the RPA. As a result, for the more complex situation of the RPA assigned at the PCC, type testing of individual inverter or generator equipment alone cannot verify compliance with the performance and capabilities required by IEEE 1547-2018. The new IEEE 1547.1-2020 testing standard now includes substantial coverage of the additional site-specific compliance verification procedures required where the DER system behind the RPA is a combination of equipment as is typical for PV farms, etc. These procedures include detailed design reviews, inspections of installed equipment, and commissioning tests. A substantial burden is placed on both the DER site developer and the interconnected utility to administer and perform these procedures.

UL 1741

Underwriter's Laboratory standard UL 1741 is the equipment safety standard applicable to inverters and DER "interconnection systems"¹⁴. UL listing of DER equipment is required by the National Electric Code in virtually all US jurisdictions. UL-1741, in addition to strictly safety measures (e.g., proper isolation of live parts, fire safety, etc.) also specifies the certification testing for compliance with IEEE 1547, with testing as defined in IEEE 1547.1.

The original UL 1741 is tied to the performance and capability requirements of IEEE 1547-2003 and the testing requirements of IEEE 1547.1-2005. Because DER penetration levels in California and Hawaii became substantial earlier than in other areas, regulators in these states realized prior to commencement of revision of IEEE 1547 that the performance requirements of IEEE 1547-2003 were inadequate to meet the needs for proper system operation and reliability. These states developed their own requirements; Cal Rule 21 and Hawaii Rule 14H, respectively. UL created a Supplement A to UL 1741, or UL 1741-SA, to enact certification test procedures related to these state requirements.

A new Supplement B, or UL 1741-SB, has been drafted to harmonize the UL certification process with the requirements of IEEE 1547-2018 and IEEE 1547.1-2020. At the time of the development of this version of the NPCC guidance document, UL 1741-SB has not completed balloting and publication. It is expected that UL 1741 SB will be completed by the end of 2021, and DER equipment certified in conformance with this standard will be widely available some time in 2022. Thus, the industry is in a temporary period where the available and adopted UL certification standards are not up to date with the most recent versions of IEEE 1547 and IEEE 1547.1. A number of utilities and jurisdictions are requiring DER equipment in the interim to be certified to UL 1741 SA. There are substantial similarities between the California and Hawaii requirements and those of IEEE 1547-2018, so this is a reasonable temporary expedient.

CSA Standard C22.3 No. 9:20

The Canadian Standards Association published their CSA Standard C22.3 No. 9:20, *Interconnection of Distributed Energy Resources and Electricity Supply Systems*, in 2020. This standard fulfills the same role

¹⁴ A packaged product of protective relays and switchgear, used to make generation sources (e.g., synchronous generators which are not covered by UL-1741) compliant with IEEE 1547 is such an "interconnection system" that falls under UL-1741. With the more expansive performance requirements of IEEE 1547-2018, which cannot be provided solely by an interconnection system (for example, relays and switchgear cannot ensure a generator's capability to ride through a voltage disturbance), this concept of an interconnection system is of limited relevance today.

as IEEE 1547, and the requirements of these two standards are substantially similar. One slight difference is that CSA C22.3 No.9:20 specifies two grades of interconnection capability, “baseline” and “supplemental”, in lieu of the three disturbance performance categories specified in IEEE 1547-2018. The CSA baseline grade is comparable to the IEEE Category I and the CSA supplemental grade is comparable to IEEE Category II.

For brevity, when IEEE 1547-2018 is cited in the remainder of this guideline document, this should be interpreted to include CSA C22.3 No. 9:20 in those jurisdictions where the CSA standard is applicable.

New DER Capabilities of Importance to BPS

Specific attention was devoted in the development of IEEE 1547-2018 to the potential aggregate impacts of DER on the BPS. This resulted in new requirements of specific benefit to BPS security. Also, this standard introduced new requirements for DER to provide increased support of the distribution systems that have some spillover impact on BPS performance. The new capabilities of relevance to BPS security and operations required of DER going forward, where IEEE 1547-2018 is adopted, are summarized in this section.

Voltage and Frequency Disturbance Ride-Through

Unlike the original IEEE 1547-2003 version which made absolutely no requirements for DER to remain on line for system disturbances of any magnitude, the new IEEE 1547-2018 specifies comprehensive requirements for DER to have the capability to ride through voltage and frequency disturbances of specified severities. The ride-through requirements are intended to reduce the risk of wide-area DER tripping due to BPS faults and frequency disturbances that could otherwise aggravate the impact of the initiating disturbance.

Ride-through requirements are specified as a function of voltage or frequency magnitude versus cumulative time for each of the system disturbance performance Categories I, II, and III. The requirements also specify ride-through for multiple consecutive disturbances, such as might occur due to unsuccessful transmission line reclosing or in storm conditions where numerous faults might occur in a short period of time. There are also requirements for DER to not trip for abrupt phase angle jumps that might occur due to transmission switching, or for rates of frequency change that can occur when the BPS generation and load are severely imbalanced such as by a major generation loss or BPS breakup.

The standard also specifies mandatory voltage and frequency protection capabilities, for which the setpoints are established by the AGIR. When these trip functions are set within the magnitude and duration ranges for which ride-through capability is specified, the trip functions will limit the actual ride-through performance. This is because the trip functions are assigned a higher priority by the standard than the ride-through requirements. The mandatory trip functions are primarily intended for protection of the distribution system. Because settings of the mandatory trip functions can constrain ride-through capability that is of increasing importance to the BPS, the needs of both the BPS and the distribution systems need to be balanced by the AGIR in establishing trip setpoints.

In the IEEE 1547-2018 parlance, “trip” means that the DER ceases to inject current into the grid and remains off line until the grid voltage and frequency are within a defined range for a specified period of time. (“Trip”, in IEEE 1547 does not necessarily mean physical disconnection, such as by a circuit

breaker.) To minimize the conflict between the BPS need for quick resumption of DER power output and the various distribution protection concerns such as islanding and fault current contribution, the standard specifies a “ride-through” mode called “momentary cessation” that applies to severe under- and over-voltage conditions. In the momentary cessation mode, the DER is not permitted to inject active (real) current and may only inject a small amount of reactive power generated by passive sources (e.g., capacitors in inverter harmonic filters). In practice, momentary cessation is implemented by blocking the gating of inverters’ transistors. This function is not feasible for synchronous and induction generator DER connected via conventional switchgear, and is thus a required capability for DER assigned to disturbance performance Category III. Momentary cessation is activated with minimal delay when a severe voltage disturbance occurs, but the DER is then required to restore normal output very quickly when the voltage recovers. DER cannot support an island or contribute fault current while in this mode thus allowing the setting of extensive DER trip delays (for which immediate return is not permitted) without imposing undue risks to the distribution system.

There has been much concern raised by the utility distribution community that allowing DER ride-through will nullify the ability of DER to detect distribution system islands, thereby exposing utility workers, customers, and equipment to risks. It should be noted that IEEE Std 1547.1-2020 specifies that islanding detection tests for certified DER are performed with the most insensitive trip settings (i.e., maximum ride-through capability) and with the most aggressive grid support functions (e.g., voltage regulation and primary frequency regulation). Because DER must pass the islanding detection tests despite these settings and functions, islanding concerns should not pose unreasonable constraints on allowing and implementing voltage and frequency ride-through capabilities that are necessary for protecting the BPS.

Frequency Response

A new requirement in IEEE 1547-2018 is for DER to have primary frequency response, in which active power is varied in proportion to frequency deviation. This performance is essentially the same as governor response in a conventional generator. This provides some mitigation of displacement of conventional BPS generation, which provide inertia and governor response, created by increased DER penetration.

There is no requirement in IEEE 1547, however, for the DER to maintain active power headroom. Because most DER (e.g., solar) is continuously operated at its maximum available power, this does constrain the response to under-frequency events as there is typically no ability to increase active power to a level greater than the pre-disturbance value. These DERs, however, will respond to over-frequency events by reduction of power output. Other types of DER, such as energy storage and engine generators, may be expected to have active power headroom most of the time for under-frequency response.

The frequency response is written as a mandatory performance requirement in IEEE 1547; i.e., it is not intended to be optional or at the discretion of the utility or AGIR¹⁵. This is specifically noted in the ISO-NE DER interconnection guidelines. A number of NPCC utilities, however, do not presently allow

¹⁵ There are frequency response droop and deadband settings that can be specified by the AGIR such that the performance is relatively inert, and inactive except for wide frequency deviations.

enablement of this function out of concern that it could defeat distribution system island detection by the DER. Extensive studies by the Sandia National Laboratory¹⁶ and EPRI have shown that grid support functions, such as frequency response and voltage regulation, do not cause inverter-energized islands to be sustained. The fact that, in an island dominated by resistive loads and energized by inverters, the relationships between active and reactive power with frequency and voltage are reversed from the usual situation in an interconnected grid, thus causing these controls to not stabilize the island. In the islanded situation, reactive power drives frequency and active (real) power drives voltage, opposite of the normal sense.

Entry and Re-Entry to Service

When going on-line, or returning to on-line status after a trip, IEEE 1547-2018 requires that DER must first sense that the system voltage and frequency are within tolerances defined by the standard, and remain within these tolerances for a specified period of time. This delay is specified by the AGIR.

Unlike the performance permitted by the original IEEE 1547-2003, large DER may not abruptly restart to their full power output. Instead, DER power must be ramped up at a rate no greater than a ramp-rate limit specified by the AGIR. As an optional alternative to power ramping, smaller DER may abruptly resume operation but with a randomized additional delay. The aggregate power ramp rate of a number of such small DER is expected to approximate a reasonably smooth ramp, thus achieving the same result from the vantage point of the BPS.

Ramped DER entry to service, and particularly re-entry to service after a disturbance, will minimize disruptions of the distribution systems and the BPS. This may be particularly important during system restoration from a BPS blackout where near-simultaneous steps in DER output can greatly complicate frequency management.

Reactive Power and Voltage Regulation Functionality

IEEE 1547-2018 requires new DER to have the capacity to produce and absorb reactive power across their active power output range, equivalent to 0.95 pf leading to 0.95 pf lagging at their rated power¹⁷. Because of the low reactance to resistance (X/R) ratio of distribution systems, the general impact of DER active (kW) power at high penetration is to elevate distribution voltages, potentially to excessive levels. Utilization of DER reactive power capabilities will generally result in DER absorbing reactive power during high output in order to hold down the distribution voltage to acceptable levels.

The standard specifies that DER have a number of different control functions to regulate this reactive power capability:

- Constant power factor mode, for which reactive power is absorbed or injected in direct proportion to DER active power output. This is the default mode, at unity pf. Where a non-unity setting is specified, it is typically a leading pf (reactive power absorption) in order to limit distribution voltage rise due to DER power export.

¹⁶ Sandia National Laboratory report [SAND2013-10231](#)

¹⁷ Certain DER assigned to normal performance Category A, typically rotating generators, may be allowed to meet slightly less stringent reactive power requirements.

- Voltage-reactive mode (commonly known as Volt-VAR) where reactive power is absorbed or injected in proportion to deviation of DER voltage from an established reference value. This is effectively a voltage regulation mode with droop. The ranges of settings allowed by the standard result in a relatively large droop; thus this mode provides a limited, non-aggressive, voltage regulation capability.
- Active power – reactive power mode where reactive power is absorbed or injected as a function of DER active power that is not necessarily linear. One application of this mode is to limit DER reactive power absorption to only higher levels of DER output where distribution voltages may become excessive. This mode is only required for DER assigned to performance Category B.
- Constant reactive power. This mode can be useful where there is a distribution voltage management system (i.e., volt-var optimization or VVO) that can provide real-time dispatch of DER reactive power. Until such systems are deployed with the necessary communications with the DER, this mode has limited practical utility.

In addition, IEEE 1547-2018 also specifies that Category B DER (the category to which inverter-based DER are typically assigned) must also have the capability of modulating active power as a function of voltage. This “volt-Watt” mode is intended for high voltage situations and may be thought of as a “graduated trip” in lieu of having DER operate at full power up to a certain voltage threshold and then abruptly trip off if their output pushes distribution voltage any further.

Note that the standard only specifies that the above functionality must be available. The actual implementation of these functions is at the discretion of the distribution utility. Out of concern for adverse interactions with existing distribution system voltage regulation schemes, utilities have generally been hesitant to implement any functions other than constant power factor (most often at unity).

Where substantial amounts of DER capacity is operating in the voltage regulation (volt-VAR) mode, there is some degree of temporary voltage support provided to the BPS. Because of the large droop of the DER regulation mode and the substantial reactance between distribution and transmission systems, the amount of BPS dynamic voltage support is limited. Also, the DER voltage regulation functionality is relatively slow-acting (seconds). Because transmission system voltages are generally decoupled from distribution system voltage levels in the steady state by on-load tap changers in primary distribution substation transformers or by distribution line regulators, any change in DER reactive power due to a transmission voltage change will fade away when the LTCs and regulators operate. Thus, DER with “volt-var” functionality enabled provide virtually no steady-state regulation of BPS voltage in practice.

As stated above, the predominate impact of DER output is to raise distribution voltage and thus the deployment of DER reactive capability, whether by an automatic function (e.g., volt-var mode) or via fixed power factor operation, is to absorb reactive power. Unless compensated by additional reactive power resources (i.e., capacitor banks) at the distribution level, the increased system reactive power demand that can be brought about by deployment of DER reactive power to mitigate distribution overvoltage issues can directly impact the transmission system. This can increase total reactive power demands on the transmission system and could potentially have adverse impacts on bulk system voltage stability.

Data Interoperability

DER are required by IEEE 1547-2018 to have data interoperability in one of three common protocols (IEEE 2030.5, DNP3, or SunSpec Modbus) to facilitate information exchange with the interconnected utility. The standard, however, does not specify or require the necessary communication links external to the DER facility.

The types of data that must be available for interchange are:

- Nameplate information that describes the characteristics and ratings of the DER.
- Configuration information that indicates the real-time capacity and capability of the DER to perform functions.
- Monitoring information that describe the present operating conditions of the DER.
- Management information, used to update functional and mode settings of the DER.

The specific data in each of these categories are specified in detail in IEEE 1547-2018.

At present, few utilities have the information infrastructure to interact with all types and sizes of DER, with only large DER facilities sometimes incorporated into conventional SCADA systems. As Distribution Management Systems (DMS) are expanded and new DER Management Systems (DERMS) implemented by utilities, this DER data interoperability will become of increasing importance. With full integration into the utility information system, this will open a host of applications and functionality that are beneficial to the BPS security and reliability, including the abilities to:

- Curtail DER active power output to limits definable in real time. This can be of particular importance in addressing over-generation issues when DER penetration reaches levels, like those already being experienced in California, where DER power output plus the minimum power of must-run conventional BPS generating units exceeds system load demand.
- Block DER from operation. This capability can be of value during BPS restoration when the variability and unpredictability of DER output could otherwise complicate the difficult task of managing the frequency of separated BPS islands.
- Provide direct visibility of the real-time output of DER. This will eliminate the “load masking” issue that presently decreases the ability of transmission system operators to maintain BPS reliability. Real time DER output information can also reduce some state estimation accuracy issues in BPS Energy Management Systems (EMS) presently caused by DER.
- Dispatch reactive power. This can be used to help manage BPS voltage.
- Protection settings can be modified in real time. This can allow the Distribution System Operator to specify DER protection settings that are beneficial to the BPS during normal operations, but change to more conservative settings when line work is performed on the particular distribution feeders to enhance line worker safety.

The interoperability of DER with utility information systems also poses new risks, as well, particularly cybersecurity. For example, a bad actor modulating the power output of DER across a wide area could potentially create oscillations of the BPS at one of the grid’s natural dynamic oscillation frequencies which could build up to a level threatening BPS stability. The issue of cybersecurity is mentioned in IEEE 1547-2018, but without specific requirements or guidance. This is an area that will need considerable

attention if the full potential of DER data interoperability can be realized. A separate IEEE Standards Association project is presently developing a Draft Guide for Cybersecurity of Distributed Energy Resources Interconnected with Electric Power Systems (IEEE P1547.3) which will provide guidance in this matter.

NPCC Interconnection Guidance

This document and any detailed specifications which follow, are intended to provide examples of general information regarding DER interconnection. The examples do not constitute a Regional Criteria (which can only be implemented through NPCC Directories and approval of NPCC's Full Members). There are numerous efforts underway in many forums and regulatory bodies that are expected to create new, more specific guidance¹⁸. The level of detail and specificity provided is intended to be used as information and guidance for any NPCC Member Area which may not have yet seen the need to establish detailed operating parameters. This document shares the practices of some Members of NPCC which have already established detailed DER requirement. Due to the rate of penetration of DER in their Area. NPCC Members considering improving or adding to their respective DER guidance documents are encouraged to reach out directly to other NPCC Members which may have already addressed DER related reliability risk issues.

Determination of DER interconnection requirements needs to be based on both distribution and BPS considerations, and coordination and communication between transmission and distribution entities is essential. The NERC SPIDER Working Group is preparing a Reliability Guideline *Communication and Coordination Strategies for Transmission Entities and Distribution Entities Regarding Distributed Energy Resources* at the time of the drafting of this NPCC Guidance Document.

Adoption of IEEE 1547-2018

IEEE 1547-2018 was unanimously adopted by the National Association of Regulatory Utility Commissioners (NARUC) in 2019. The standard outlines the technical specifications and performance requirements which are universally needed for interconnection and interoperability of DER and should be sufficient for most installations. It is recommended that the requirements in IEEE 1547-2018 be referenced in the interconnecting utility requirements as well as any further state interconnection requirements as appropriate.

Implementation guidance for IEEE 1547-2018 provided by NERC may be found here: [Guideline IEEE 1547-2018](#). EPRI has also developed a model technical interconnection requirements document that implements IEEE 1547-2018, to which utilities and regulators might refer, and may be found here: <https://www.epri.com/research/products/000000003002022563>.

The applicability of certain specifications and requirements are dependent on specific application considerations. For these, the requirements are provided in terms of a limited number of technology-

¹⁸ At the time of this guidance document development, these include but are not limited to: NERC (e.g. SPIDER WG, Inverter- Based Resources Task Force (IRPTF), Events Analysis, Modelling and Standards process), IEEE (IEEE Std 1547.1-2020, P2800), and various state initiatives such as the New York Interconnection Technical Working Group (ITWG), Other regional, Provincial and State initiatives.

neutral performance categories, for which it is the responsibility of the authority governing interconnection requirements (AGIR) to consider. Within New England, interconnection requirements vary by state, and further, by Distribution Provider. In New York a common set of DER interconnection requirements exists (Standardized Interconnection Requirement – SIR).¹⁹ Several other state and provincial AGIR have developed local interconnection requirements which are listed in [Appendix E](#) of this document along with links which will be helpful to access specific interconnection information²⁰. These requirements are then supplemented by individual Distribution Provider interconnection agreements, specifications, and requirements.

The DER owner, responsible for its operation, must follow Interconnection Agreements and any AGIR requirements for fault ride-through. Distribution Providers and other AGIR entities should ensure that their requirements describe necessary DER performance with ride-through capabilities for frequency and voltage excursions events. Interconnection Agreements and local requirements generally have provisions to provide documentation upon request.

DER Equipment Certification

It is recommended that all applicable inverter-based applications should:

- be certified per the requirements of UL 1741 SB (when such equipment becomes widely available).
- have the voltage and frequency trip settings as specified by the interconnecting utility
- have the abnormal performance capabilities (ride-through)

UL 1741 SB has not yet been approved and published at the time of the writing of this guidance document, due to certain issues related to the fine details of product testing. Approval, however, is imminent and there will be some time required for inverter manufacturers to have their equipment type-tested at Nationally Recognized Testing Laboratories (NRTLs) and to deplete current inventories of equipment with the prior certification. A date 12 months after final UL-1741 SB publication is a reasonable target date after which new DER interconnection applications should be required to have UL 1741 SB certification.

Inverters certified to UL 1741 (no supplement; i.e., not UL 1741 SA or SB), in accordance with the requirements of the original IEEE 1547-2003, do not provide adequate grid support functionality. In the interim period until DER certified to UL 1741 SB, in accordance with IEEE 1547-2018, alternative criteria for inverter-based DER certification are needed. For example, in one NPCC Area the following approach was taken to assure that inverters are installed with a standardized set of grid support functionality to ensure the reliability of the BPS (e.g. maintaining acceptable system frequency and voltage):

- Should be compliant with only those parts of Clause 6 (Response to Area EPS abnormal conditions) of IEEE Std. 1547.1-2018 (2nd ed.) that can be certified per the type test requirements of UL 1741 SA (September 2016).

¹⁹ These requirements pertain only to interconnections to the electric utilities regulated by the NY State Public Service Commission, which are the investor-owned utilities. Separate requirements apply to interconnections to the Long Island Power Authority system, which is a public utility.

²⁰ Some of these existing requirement documents may not yet have incorporated or addressed IEEE 1547-2018.

- May be sufficiently achieved by certifying inverters as grid support utility interactive inverters per the requirements of UL 1741 SA (September 2016) with either CA Rule 21 or Hawaiian Rule 14H as the Source Requirement Document (SRD). Such inverters are deemed capable of meeting the requirements of this document.
- Applications should have the voltage and frequency trip points and abnormal performance capabilities consistent with IEEE 1547-2018, PRC-024-2 and PRC-006-NPCC “Automatic Underfrequency Load Shedding.”
- For abnormal performance, Category III inverters should be recommended for use. (There may be some circumstances, such as certain types of fuel cells) where the primary energy source may not allow practical implementation of Category III performance. Specification of Category II performance in abnormal conditions may be acceptable in these limited cases.)

Once UL 1741 SB inverters become pervasive, the measures in the first and second bullets above are no longer applicable or necessary.

In New York State it is recommended that equipment be selected from the Department of Public Service “Certified Interconnection Equipment list” maintained on the NY Public Service Commission’s website. Interconnected DG systems utilizing equipment not found in such list should meet all functional requirements of the current version of IEEE Std. 1547-2018 and be protected by utility grade relays (as defined in these requirements) using settings approved by the utility and verified in the field. The field verification test in New York State must demonstrate that the equipment meets the voltage and frequency requirements detailed in this section. Individual New England state interconnection standards and agreements also typically refer to IEEE Std. 1547-2018 functional requirements and include protection setting review requirements.

DER Protection Settings

The DER owner’s protection and control equipment is required by IEEE 1547-2018, and by all utility technical interconnection requirements, to cease to inject current or automatically disconnect the generation from the system to which it is directly connected, upon detection of frequency or voltage excursion conditions exceeding specified time and duration trip points. Ride-through is not a directly configurable or settable DER parameter. It is a characteristic of the specific DER equipment which, for certification, must exhibit at least the ride-through minimum ride-through capability specified by IEEE 1547-2018. The settable parameters are the DER trip settings which effectively terminate ride-through and the ranges of settings allowable by the standard encroach upon the standard’s ride-through capability requirements. Where necessary, the trip settings specified by the AGIR may limit the actual availability of the DER’s physical ride-through capability. In essence, the ride-through requirements are effectively determined by the utility or AGIR via the trip settings, and are not necessarily the ride-through capability requirements specified in IEEE 1547-2018.

DER protection functions (frequency and voltage) protections are primarily intended to protect worker and public safety at the distribution level, allow clearing of distribution faults, coordinate with distribution protections systems, and minimize impacts to distribution system and customer equipment. These distribution-focused objectives drive toward sensitive DER tripping while the maximization of disturbance ride-through via insensitive settings is critical to the BPS reliability, particularly as DER

penetration increases. These mutually-opposed objectives need to be carefully balanced by considering both distribution and transmission system needs in the specifications of DER protection settings.

IEEE Std. 1547-2018 addresses the issue of wide-scale DER tripping due to BPS events by setting the default DER trip settings for Category II at a level that coordinates with NERC standard PRC-024-2 “Generator Frequency and Voltage Protective Relay Settings.” This is the standard that defines limitations to voltage and frequency protective relay settings for generators connected to the transmission system.²¹ Requiring DER to ride-through disturbances, similarly to large generators, would be a significant step towards achieving a robust level of reliability in a cost-effective manner. Greater protection of BPS reliability can be obtained by requiring Category III performance without undue compromise of distribution issues due to the “momentary cessation” functionality required only of Category III DER.

The required DER “abnormal performance category” and the required voltage and frequency trip settings should be clearly and unambiguously communicated by the interconnecting utility to the DER developer or owner in the utility’s technical interconnection requirements document or interconnection agreement. As a minimum within NPCC, DER voltage and frequency tripping requirements should be no more sensitive than specified in NERC PRC-024-2 for the specific interconnection.²² Interconnection agreements should clearly require that any protective equipment or setting specified by the utility shall not to be changed or modified at any time by the DER owner without consent from the utility.

ISO-New England also has developed a technical bulletin, contained in [Appendix F](#), which outlines required settings for inverters in New England.

Additional Utility Requirements for DER Protection

IEEE 1547-2018 and the conformance testing requirements of IEEE 1547.1 and UL-1741 were developed with the intention that certified DER units are to be self-sufficient with regard to the voltage and frequency protection functions. Many utilities, however, specify additional protection functions or functions redundant with those of the DER units, implemented using utility-grade protective relays. In addition, the assignment of the Point of Common Coupling with the utility-system as the Reference Point of Applicability by the standard in the case of certain larger DER facilities usually requires separate protective relays in practice, using measurements at the PCC.

The need for additional protective functions will be determined by the utility on a case- by-case basis. Protective system requirements for DER facilities result from an assessment of many factors, including but not limited to:

- Type and size of the DER facility
- Voltage level of the interconnection

²¹ NERC PRC-024 is not strictly a ride-through requirement as it only has the scope to limit how protective relays are set that will trip BPS generators, but does not prohibit tripping of generators due to indirect effects of voltage or frequency deviations such as failure or tripping of plant auxiliary equipment (e.g., boiler feed pumps). However, in practice, the limitations on unit protective relay settings will achieve ride through in most cases.

²² NERC PRC-024 establishes different frequency protection setting limitations for Quebec than for the Eastern Interconnection, which applies to the remainder of NPCC outside of Quebec.

- Location of the DER facility on the distribution circuit
- Distribution transformer
- Distribution system configuration
- Available fault current
- Load that can remain connected to the DER facility under isolated conditions
- Amount of existing DER on the local distribution system.
- Presence of a ground source within the DER facility

Under/over voltage (27/59) and over/under frequency (81O/81U) functions are directly required by IEEE 1547 and are incorporated within certified DER units. Separate utility-grade protective relays may be required by the utility for redundancy, or may be necessary for a larger DER facility to meet the requirements of the standard where the PCC is specified as the RPA. Overcurrent protection (50P/50G/51P/51G) may also be required by the utility. It should be noted that overcurrent protection may not be effective for detection of external (outside of DER facility) faults in the case of inverter DER due to the lack of significant fault current contribution. Where overcurrent protection is specified for synchronous and induction generators, settings should avoid defeat of ride-through.

DER protection equipment should utilize a non-volatile memory design such that a loss of internal or external control power, including batteries, will not cause a loss of interconnection protection functions or loss of protection set points. Interconnection Agreements and standards should require that DER protective devices utilize their own current transformers and potential transformers for protection and not share electrical equipment associated with utility revenue metering.

Distribution System Protections

Protection systems applied by the utility should not be applied or set such that these will trip the DER, or the feeder to which the DER is connected, as a result of a BPS fault that creates voltages at the DER that are within ride-through requirements. This includes protections at the DER facility point of interconnection (e.g, utility-owned recloser), along the feeder (line recloser), or at the distribution substation. Figure 2 shows some of the protections that might be applied within a DER facility and on the distribution system. Only the protections within the DER facility, shown by the blue dotted box at the left side of the figure, are in the scope of IEEE 1547 and DER technical interconnection requirements. Protections to the right of the PCC in this diagram are potentially applied by the distribution utility.

There has been consideration of using negative sequence voltage protection (Device 42) to detect transmission ground faults that might cause a radially-fed distribution substation to become islanded, causing a loss-of-grounding situation and resulting unfaulted-phase overvoltage (“3V0” issue) on the transmission side.²³ Such protection should not be set such that it trips for any other transmission fault other than one on the radial transmission feed to the substation, which can be extremely difficult. Widespread deployment of such protection, with excessive sensitivity could cause widespread loss of DER capacity as a result of an ordinary BPS fault.

²³ Pterra Report R106-18 [Alternate Mitigation and Design Options to 3V0 Requirement](#) for NYSEDA research project.

Certain protective relay manufacturers have actively marketed a relay based on phase jump or rate-of-frequency change to utilities for application to utility-owned DER interconnection reclosers. The intended purpose of these relays is to detect DER-energized islanding of the distribution feeder. The settings recommended by the relay manufacturer are far more sensitive than the phase jump and rate-of-frequency change ride-through requirements specified by IEEE 1547-2018. Although this standard applies only to the DER, and not directly to the interconnected utility, application of relays with settings more sensitive than the DER ride-through requirements obviously defeats the intent of the DER requirements and thus pose a risk to the BPS. Any such protection should be coordinated with DER ride-through, which will likely diminish the effectiveness of such protections as island detection means. It should be noted that certified DER are required to have their own island detection capabilities, making such utility-applied protection redundant. The internal DER anti-islanding algorithms typically use active means, allowing these to be far more effective than passive relays such as has been advocated.

Overcurrent protection of distribution feeders is ubiquitous. DER with high fault current contributions can potentially cause reverse current flow through the distribution feeder and the substation into a transmission fault. Non-directional feeder overcurrent relays can potentially trip, removing the feeder and all connected DER for a contingency that the DER would otherwise ride through. This is a practical issue only for relatively large synchronous generator DER because inverter DER has very minimal short-circuit current contribution. Application of directional overcurrent relays that trip only for feeder faults can be a possible solution.

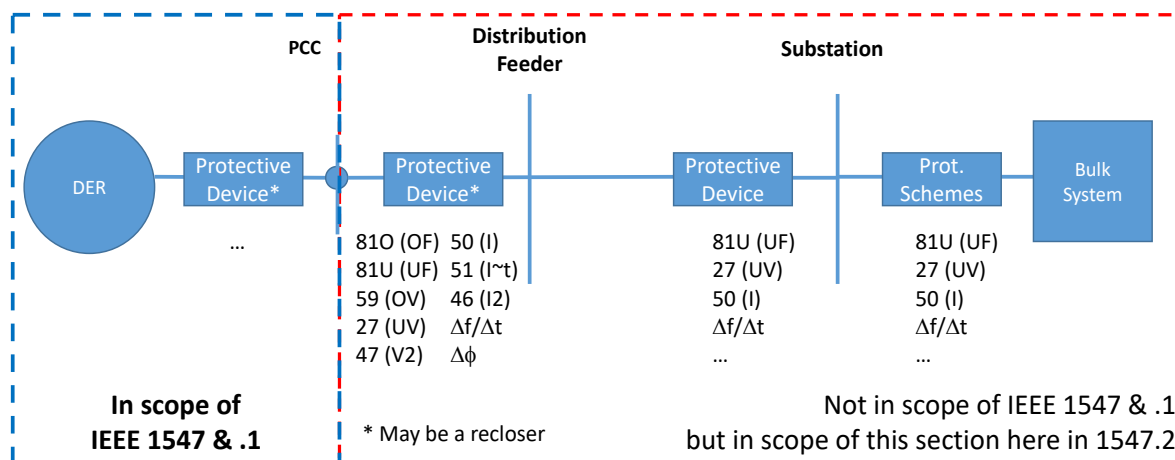


Figure 2: Scope of IEEE 1547 series of standards and guidelines and list of distribution protective functions that may interfere with DER ride-through. Source: Provided courtesy of EPRI²⁴

DER Return to Service Following Trip

Utilities in other parts of the Eastern Interconnection who have experienced increased levels of DER have determined that during system restoration, DER should not be allowed to return to service until

²⁴ EPRI makes no warranty or representations, expressed or implied, with respect to the accuracy, completeness, or usefulness of the information contained in the Material. Additionally, EPRI assumes no liability with respect to the use of, or for damages resulting from the use of the Material.

the system has been reestablished and is in a stable operating state. Interconnection Agreements and standards should address necessary communications and SCADA requirements.

If a DER is tripped by a protective function, the DER is prohibited from returning to service²⁵ by IEEE 1547 until the voltage and frequency at the DER have recovered within acceptable limits, and remain so for a specified amount of time. Interconnection Agreements or utility technical interconnection requirements standards should address delay times for return to service. DER interconnected in accordance with IEEE 1547 will automatically return when the voltage, frequency, and delay constraints are met. Per IEEE 1547-2018 Clause 4.10.3, the allowable range of delay settings is 0-600 seconds with a default setting of 300 seconds. This standard also allows a power recovery ramp rate to be specified. IEEE 1547-2003, in clause 4.2.6, allows an adjustable delay or a fixed delay of 5 minutes and does not require power ramping.

The return-to-service delay time specified by interconnection agreements should be coordinated to support BPS reliability as well as distribution requirements. Short delay times quickly restore the generation resource provided by DER, which may be of increasing importance in the future where the evolution of the grid is toward reliance on DER to contribute to meeting load demand and to offload the transmission infrastructure. Longer delay times tend to be favored for distribution considerations. Where DER are interconnected to utility information systems such as SCADA, DMS, or DERMS, using the interoperability functionality specified by the new standard, resumption of DER operation can be blocked if necessary by changing the DER's "permit operation" logical to FALSE after a trip event.

Some NPCC utilities have established additional DER operating limitations, beyond those specified in IEEE 1547. Example limitations are:

- DER systems greater than 25 kW that do not utilize inverter-based interface equipment should not have automatic reclosing capability unless otherwise approved by the utility.
- Some DER, based on size or other characteristics, must receive permission to return to service. For these, any automatic reclosing functions must be disabled and verified to be disabled during verification testing.

As conventional resources on the BPS are displaced and the grid becomes increasingly reliant on grid edge DER on the distribution system, black start, and system restoration plans will need to be adjusted accordingly.

Frequency Response Settings

DER active power response to frequency deviations (i.e., similar to governor response of a conventional generator) is required by IEEE 1547-2018. The parameters of this function (droop and deadband) should be specified by the AGIR or utility in the DER technical interconnection requirements document or interconnection agreement. The benefit of this new function on BPS reliability can be best achieved if these parameters are the same as specified for BPS generating plants. Disabling or rendering this

²⁵ Prior versions of this NPCC guidance document used the term "reconnect". However, IEEE 1547 does not require physical disconnection when a DER is tripped; only cessation of active (real) current injection and restriction of reactive current is required. For inverters, this is typically accomplished by electronic means.

function inert via parameter settings deprives the BPS functionality that will become increasingly important in the future with increased DER penetration.

Reactive Power Control Settings

The setting of reactive control mode (e.g., volt-var, constant power factor, etc.) and the specific parameters of these modes are primarily determined by distribution system needs. The DER reactive power control settings, however, will have some impact on the BPS as well. There can be significant constraints on reactive power control modes, such as volt-var, that can potentially interact adversely with existing distribution feeder voltage regulation schemes. The reactive control setting policies determined by the distribution utility, including the resulting impacts on net distribution substation reactive power load, should be communicated to the transmission planners to ensure accurate system modeling.

Information Integration and Communications

Integration of DER into utility operational information and control systems (SCADA, EMS, DMS, DERMS) will become increasingly necessary as DER penetration increases, displacing conventional BPS resources that have long been under the direct observation and control of Transmission System Operators. Member utilities should consider developing IT Infrastructure plans to provide two-way information flow between DER and system operators. This will provide situational awareness necessary for reliable operation of the BPS, communicate DER generation limits where necessary to avoid over-generation and other operational issues, and facilitate dynamic control of DER settings to protect BPS security while minimizing distribution line worker hazards. Many areas and utilities are either in the process of, or determining the value of, adding distribution system platforms to deal with DER aggregation, observability, availability and status of DER. NPCC will continue to monitor the development and deployment of these Distributed Energy Resource Monitoring Systems (“DERMS”).

Prior to possible future implementation of large-scale DER management systems (DERMS) that work with DER of all ratings, inclusion of larger DER facilities in present operational systems such as SCADA can be beneficial to BPS security. At this time, the majority of DER capacity in the NPCC area is provided by larger DER facilities which can be integrated into SCADA more feasibly than the larger number of small DER (e.g., residential PV). It is recommended that DER larger than a certain aggregate facility rating, as determined by the interconnecting utility or System Operators, should be required to provide SCADA telemetry data to a control center to monitor their output. It might be beneficial to have DER data communicated to a Distribution System Operator, distribution system platform or similar, to provide analysis and aggregation of DER output data within a given area and map those to individual transmission nodes as a concise summary to the transmission system operator. Scan rates equivalent to the scan rates used by the Transmission System Operator are preferred (typically in the 6 second range).

In New England, for monitoring and control of new DG projects, [Appendix E](#) lists current interconnection documentation and standards for DER by State. The DER communications hardware, protocols, and data models must comply with these state and local interconnection utility standards.

In New York, for monitoring and control of new DER projects, the most current version of the Monitoring and Control Criteria should be employed by the utilities to evaluate the need for such equipment in New York. The New York Monitoring and Control Criteria document was developed and

agreed to through a collaborative process as part of the Interconnection Technical Working Group (ITWG)²⁶. The communications hardware, protocols, and data models must comply with local interconnection utility standards.

Some NPCC Members have encountered difficulty with obtaining information and data from DER operators. DER owners should be encouraged (or preferably, required) to keep their end of any SCADA equipment functional and reconnect their telemetry devices when they have been disabled. The utility system operator should be alerted by the DER when telemetry is interrupted. These requirements can be implemented via technical interconnection requirement standards or interconnection agreements.

Although IEEE 1547-2018 defines and requires a communication port, the path that a utility may use for data from that communication port may pose a cyber-security risk if not adequately secure. It is suggested that full consideration be given to cyber security risks when transferring data until such time as the IEEE 1547 has been amended to require cyber security protections.

NPCC Planning and Operational Guidance

Forecasting DER Capacity

Accurate forecasting of DER capacity increase is critical to planning a reliable BPS with high DER penetrations on the horizon. The DER capacity and allocation by type (PV, battery, etc.) and interface technology (i.e., inverter or machine) is important to various aspects of resource planning, transmission planning, and BPS operations.

The growth of DER is greatly dependent on public policy and the economics of DER ownership. Policy drivers include feed-in tariffs, state Renewable Portfolio Strategy (RPS) programs, net energy metering and tax credits. In addition to subsidies and tax treatment provided by policy, DER ownership economics are greatly affected by equipment and installation costs, electric rates and wholesale energy prices. Land use and zoning restrictions, as well as distribution system hosting capacity constraints can potentially cause saturation of DER development at some point in the future; which must also be considered in forecasting.

The trend has been for future DER capacity to be underestimated. The recent history has been that factors favorable to DER have developed faster than forecast. An example is shown in Figure xx, which shows the future ISO-New England DER forecasts for each of eight successive forecast updates, showing forecasts for any given out-year continually increasing as that year is approached.

²⁶ This document can be found on the Department of Public Service website (www.dps.ny.gov) at the Distributed Generation/Interconnections tab under Interconnection Technical Working Group Information.

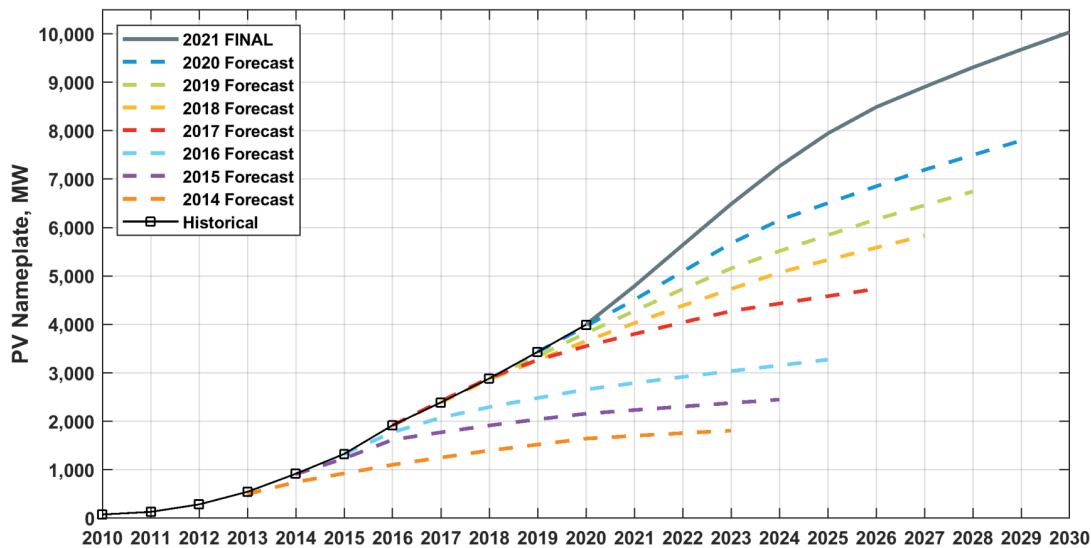


Figure 3: Trend in PV nameplate capacity growth forecasts in the ISO-New England system, compared to actual historical values. Source: ISO-NE Final 2021 PV Forecast

NPCC members should ensure that DER capacity forecasts are based on best practices, which are continually evolving as DER becomes an increasing significant factor in system planning and operations.

Monitoring Present DER Capacity

Actual DER capacity needs to be continually monitored on a regular basis, both to guide system operations and to provide feedback to correct forecasting efforts. Information related to DER in-service dates, capacity value, availability, emergency assistance, scheduling, and deliverability should be available to the planners. Modeling, data, and other necessary information should be defined and made available to those needing it, such as system planners and system operators. Any requirements associated with this information should be in Interconnection Agreements or Tariffs prior to any commissioning of the DER. Mechanisms for DER entities to provide this information are evolving, depending on locality, and subject to change as DER penetration increases. NERC has prepared a [Reliability Guideline DER Data Collection for Modeling](#) that provides recommendations and industry practices for the mandatory and optional DER data to be collected by the Reliability Coordinator as well as on how, where, and when to gather such data.

Resource Planning

DER is becoming a significant factor in determining resource adequacy projections out to the planning horizon. DER can either be considered as a capacity resource, particularly for DER that participates in forward capacity markets, or as a load modifier, as in the case of behind-the-meter resources. The contributions of DER to resource adequacy are dependent on the type of DER and how the availability of DER output coincides with periods of critical system load demand. An obvious example is that PV contributes to meeting summer load peaks, but often does not contribute to meeting winter load peaks that typically after sundown. Consideration of possible correlation in meteorological factors affecting the output of DER with those affecting load demand is also necessary.

A recent factor has been the accelerating application of battery energy storage systems as DER. The potential contribution of ESS to system resource adequacy is totally dependent on how the ESS owner operates their system. If an ESS owner participates in the forward capacity market, the practices for including these resources into the system capacity are well defined. If the ESS is operated for the owner's local needs, such as minimizing demand charges or exploiting time-of-use rates, there is strong correlation between ESS output and system demand, but the relationship is not absolute. This resource, for example, would not necessarily respond to a generation insufficiency caused by a major generating unit outage at other than a high load period .

The inclusion of DER into the resource planning process should include analysis of DER capacity factors, hourly correlations of historical DER output with load patterns, and considerations of DER owner motivations in the case of controllable distributed generation or storage.

Operational Forecasting

Reliable system operation relies on real-time knowledge of the state of the system, including its generation resources and load demand. This is critical to determining operating reserves and to anticipate rapid changes in the generation and load balance, such as the late afternoon decrease of PV DER output simultaneous with evening load demand increase.

Due to the present limited DER visibility, system operators must depend on estimations and forecasts to separately identify actual load demand and DER output from the observable net load. There is a need to develop and implement improved techniques for making such estimations, including use of meteorological observations and specialized meteorological forecasts (e.g., observations and forecasts of solar irradiance over the operating area). Implementation of DER managements systems (DERMS) by distribution system operators will help improve this operational visibility if the DERMS are integrated with the transmission system operator's EMS.

DER Curtailment

Increased DER penetration can potentially lead to periods of over-generation if not properly addressed by System Operators. Interconnection agreements or other state or local requirements may require DER installations to provide communication channels so that generation can be curtailed as necessary as determined by a central dispatch authority. This is practical, at this time, for only larger DER facilities that can be integrated with SCADA but future implementation of DERMS will facilitate control of most or all DER. Procedures to determine which DER generation to curtail should be in place. In lieu of operating procedures, some areas of the country are planning to use market mechanisms to address this issue but how these market mechanisms will work with smaller behind-the-meter (both commercial and residential) needs further definition.

Automatic Under-Frequency Load Shedding (UFLS) Programs

NERC has a set of requirements in the PRC-006 standard, and NPCC has more stringent requirements in NPCC's Regional Standard, PRC-006-NPCC ²⁷, which outline expected UFLS performance. Approved and effective versions of these standards may both be found on the NERC website. The NERC SPIDER

²⁷ Effective Date of the Standard is 4/1/2020 subject to the Implementation Plan and specific area regulatory approvals

Working Group is presently developing a Reliability Guideline *Recommended Approaches for Developing Underfrequency Load Shedding Programs with Increasing DER Penetration* that will provide useful guidance.

SS-38 is the NPCC working group responsible for inter-Area dynamic analysis. The SS-38 Working Group regularly studies the UFLS performance within the Region and has recently completed sensitivity analysis showing that a moderate increase of DER penetration anticipated in the short term will not result in any significant degradation in the UFLS program performance based on the conditions and assumptions used in the analysis.

Adopting a more flexible approach to UFLS may be necessary as DER penetrations reach higher levels. There are utilities that are reviewing the feasibility of “Adaptive UFLS” which uses real time monitoring of distribution feeder loads and their DER to determine how much additional load may need to be tripped when DER has increased output. Some utilities, such as Duke Energy avoid choosing those distribution feeders for the UFLS program that have DER interconnected to them.

In the future, nearly all distribution feeders will have at least some DER connected, thus it will be necessary to identify feeders for UFLS implementation where DER penetration is sufficiently low such that net load levels are not substantially reduced by DER. With increased penetration, the number of feeders having reverse power flow will increase. These feeders will need to be identified so that selection of these feeders for UFLS can be avoided. Feeder-level UFLS may eventually become inadequate, and technology may need to be developed to implement UFLS on a more granular basis, perhaps at the customer level.

Transmission Planning Models

DER penetration will modify transmission system net loading patterns and generator dispatch, as well as the dynamic performance of the BPS. Planning models will need to be based on forecast DER capacity as well as the amount of DER active power output at the relevant time for the case. Planning analysis may no longer be limited to the peak load and off-peak load levels as the DER output is a separate parameter that has its own diurnal and seasonal patterns, leading to combinations of load and DER generation that may create additional critical grid conditions. The NERC SPIDER Working Group is presently developing a reliability guideline *Bulk Power System Planning under Increasing Penetration of Distributed Energy Resources* that can be referred to when completed.

DER penetration forecasts will need to be determined specifically for each transmission bus, much as system load is forecast today. The DER penetration will need to be segregated by type because the output patterns differ significantly; for example PV has an average daily output pattern while cogeneration and waste-gas DER tend to have constant output. Because of the rapid growth of DER penetration, there should be a mechanism to continually ensure that the Distribution Provider transmits any necessary information pertaining to capacity, operational characteristics, etc. of DER facilities to transmission system planners. The NERC SPIDER Working Group is presently developing a reliability guideline *DER Forecasting Practices and Relationship to DER Modeling for Reliability Studies* that can be provide guidance when completed.

For steady-state (loadflow) analysis, it can be sufficient to model the net load (actual load demand minus the DER output). Because there are typically on-load tapchangers on primary distribution substation transformers or distribution feeder voltage regulators isolating the distribution system from steady-state transmission voltage levels, the net reactive load can be modeled in the normal manner as a constant reactive power load, even if DER have voltage regulation functionality enabled. The modeled net reactive power load, however, should take the DER reactive power which may be due to non-unity power factors or voltage regulation functions (i.e., “volt-var” mode) specified by the distribution utility. DER may consume relatively large reactive power during high DER output in order to compensate for distribution feeder voltage rise resulting from reverse active power flow interacting with the distribution feeder resistance.

Reasonable modeling of DER in dynamic (stability) analysis simulations will be of increased importance with DER penetration growth. Netting out DER output from load demand, however, is highly inaccurate for dynamic analysis when there is any significant amount of DER contribution at a load bus in the transmission system model.

A relatively new dynamic model DER_A is available in the common loadflow/stability software packages. This model provides a good framework for modeling inverter-based DER, including newer DER with the advanced features required by IEEE 1547-2018. Because most DER is located on the distribution system relatively close to loads, the model will be more accurate if combined with appropriate modeling of distribution load such as by the composite load models available in the software. NERC guidance recommends dividing DER between larger utility-scale applications (U-DER) and small behind-the-meter (R-DER) applications. The guidance suggests that U-DER (e.g., PV farms providing wholesale generation) facilities are located very near the distribution substation or on dedicated distribution feeders and thus should be modeled by a DER_A model connected directly to the load bus, whereas R-DER should be located with the load downstream of the equivalent feeder impedance. In the NPCC area, it is common that large DER facilities are located on ordinary distribution feeders distant from the substation and relatively close to loads. Location of U-DER directly at the distribution bus or on dedicated feeders is relatively rare in the NPCC area, and modeling practices should take this into account.

Parameterizing the DER models requires considerable effort, however. This requires extensive information regarding the total DER at each load bus of the transmission model, including aggregate inverter DER capacity, type (e.g., PV, battery, etc.), tripping setpoints, voltage and frequency regulation parameters, etc. The DER dynamic model parameterization process requires extensive cooperation and communication with distribution system planners and the utility entities managing DER interconnections. In most cases, the DER at any bus will be a mix of characteristics and thus considerable engineering judgement is needed to determine the parameters of the model representing the aggregation of these resources. For example, DER installed with older interconnection agreements may reference prior versions of IEEE Std. 1547 and may not meet current ride through requirements. The NERC SPIDER Working Group has developed a Reliability Guideline [DER_A Model Parameterization](#) that may be consulted

Accurate modeling of DER in dynamic studies performed to design UFLS programs will become critically important, particularly the frequency response characteristics of newer DER and more importantly the frequency tripping setpoints of all vintages of DER. While new DER, in accordance with IEEE 1547-2018,

will have sufficient frequency ride-through capability to avoid tripping prior to UFLS activation thresholds, legacy DER may not. Also, DER frequency trip points specified for DER by distribution providers and frequency protection (including rate-of-change-of-frequency protection) installed at DER points of interconnection by the utilities may defeat some of the ride-through capability. Specific attention to both DER and distribution frequency tripping characteristics is essential to future UFLS design studies.

Short Circuit Analysis

The majority of DER installed in most areas is inverter based, and inverters have a relatively small current contribution to short circuit faults. Current into a three-phase short-circuit near the inverter terminals is typically on the order of 1.1 to 1.2 p.u. of the inverter's rating. Individual phase currents during an unbalanced faults may be somewhat greater depending on inverter control design, but typically not more than approximately 1.5 p.u. For faults on the BPS, the fault current contribution from the aggregation of DER will not be great, but could be of importance in certain cases such as where the fault current from BPS generating units is small and DER penetration is high in the local area of the fault.

Unlike a synchronous generator, which acts as a voltage behind an impedance and thus short circuit current is strongly affected by the impedance between generator and fault, inverters behave as constant current or constant power sources. This means that the fault current contribution is relatively invariant with impedance between inverter and fault. The conventional means of modeling short-circuits in analysis programs cannot correctly represent inverter sources. The major fault analysis software vendors have added new "voltage-controlled current source" models to their programs. This type of advanced model should be applied to represent inverter-based DER if it is judged necessary to include DER fault contribution in transmission short circuit studies. Using a conventional voltage source model to represent inverters will result in inaccurate results.

It should be noted that the voltage-controlled current source models in short-circuit programs were originally focused on representation of large-scale wind turbines that typically have fault performance characteristics based on certain European grid codes. There is a wider variety of inverter characteristics within the DER space, with some also built in conformance with these grid codes and others not. For example, some inverters inject a precise amount of negative sequence current in proportion to negative sequence voltage during unbalanced faults (effectively, a defined negative sequence impedance), while other inverters controls cancel out all negative sequence current (providing a near infinite negative sequence impedance). Still other controls provide no specific intentional response to negative sequence voltage and provide an effective impedance that is almost never documented. While the available voltage-controlled current source models in short-circuit analysis software are adequate for modeling inverter-based DER, some of the guidance provided with the programs regarding appropriate parameters is based on the wind turbine context and may not represent accurate assumptions of DER inverter characteristics.

A smaller portion of DER capacity is in the form of synchronous and induction generators, such as used for small hydro, waste gas engines, combined heat and power (cogeneration), etc. These generators contribute a much greater current to a close-in fault, relative to their ratings, than do inverters. However, the relatively small aggregate capacity of this type of DER at most transmission buses is small, minimizing the impact on transmission fault currents in most cases. Where there are relatively large

synchronous and induction generator DER capacities in distribution systems connected to the transmission system near transmission fault locations, these should be represented in transmission short-circuit studies using ordinary generator models.

DER Recommendations

As DER continues to proliferate within the NPCC Region we suggest the following initial activities:

Participation in National DER Forums

- 1) Participate in efforts to fully understand the issues and best practices associated with DER.
- 2) Engage NPCC and its members to address the issues and provide expertise.
- 3) As the understanding of the issues and best practices matures, then NPCC will be well positioned to understand the regional differences that need to be considered.

Process and Risk Management Recommendations

- 1) Continue with sensitivity analysis at the Transmission level for various levels of penetration of DER on the distribution facilities to determine effects of increased penetration levels of DER on BPS performance.
- 2) Pursue further opportunities to coordinate distribution and transmission requirements for DER, share Member best practices, and promote consistency regarding DER installations where possible within the NPCC region.
- 3) Continue to review and identify approaches to coordinate NPCC AGIR and utility interconnection requirements relative to DER to identify dissimilarities between Areas which may negatively impact reliability.
- 4) Identify opportunities to share information regarding DER related reliability risk problems and solutions and promote sharing.
- 5) Encourage consideration of developing IT Infrastructure plans to aggregate and report critical DER Status to BPS Operators.
- 6) Continue to solicit and address observable reliability related issues of DER using NPCC's DER Impact Reporting Forms and its associated process.
- 7) Continue to discuss any changes required for System Restoration and Blackstart Plans, as a result of increased DER.
- 8) Continue to follow DER related ESA ESS safety issues and associated recommendations and share the results with NPCC stakeholders.
- 9) Avoid placement of UFLS on distribution feeders which have a significant amount of DER relative to the feeder's load if possible, unless sufficient telemetry exists to ensure proper functionality of the UFLS program as a whole.

Planning Related Recommendations Due to Changing Resource Mix

- 1) Identify and consider new methods to obtain and facilitate collection of DER modeling and performance data to enable Long-Term Resource, Long-Term Transmission and Operational Planning of the BPS²⁸
- 2) Clearly identify DER in the NPCC Region's Area interconnection queues or forecasts where DER is being proposed for installation, including the magnitude and location relative to the existing resource base and load projections.
- 3) Address masking of load by DER at the distribution level to ascertain its impact on the behavior of load, as well as the assumptions that underpin UFLS programs.
- 4) Determine the appropriate entities responsible for providing DER data to the Planning Coordinator for the purposes of model building and maintenance and ensure that this data is provided.

Analytics and simulation recommendations to deal with increased system complexity

- 1) Support interconnection wide inertia loss study efforts, to determine potential reliability impacts, as DER replaces conventional synchronous generation resources.
- 2) Obtain DER modelling data to be able to model, predict and examine system behavior and assess the interactions between the new resources and the existing reliability preserving systems and programs. Examples include:
 - a. Dynamic behavior of the transmission system
 - b. Sudden loss of large amounts of DER due to transmission system events
 - c. Under Frequency Load Shedding,
 - d. Under Voltage Load Shedding,
 - e. Frequency response sharing mechanisms (BAL standards).
 - f. Analysis of system protection systems (both T and D) so that the parameters to set protection systems and other control systems are known to permit the most reliability benefits to be garnered from the new resources.
- 3) Determine the transmission and distribution benefits and challenges of DER fault-related dynamic voltage support.
- 4) Determine the value to the transmission and distribution systems of the different DER steady-state voltage/reactive power control.

Implementation of IEEE-1547-2018

- 1) Work with the AGIR to assign abnormal performance categories for DER certified as meeting IEEE Std. 1547-2018. For example, synchronous generators could be Category I. All inverter-based generation could be Category III. Exceptions could be allowed for inverter-based technologies that could not meet category III and did not constitute a significant penetration. Exceptions could need to be agreed to by both the distribution and transmission entities.
- 2) Develop standard voltage trip settings (1547-2018 Clause 6.4.1) that provide for BPS reliability. For example for Category III, UV1 could be set at 0.88 p.u. & 3.5 seconds to coordinate with PRC-024-2 at 0.88 p.u. & 6 seconds to coordinate with PRC-024-2 with margin for Fault Induced

²⁸ Questions exist regarding which entities should be responsible for providing DER data to the Planning Coordinator for the purposes of model building. NERC is working on this issue.

Delayed Voltage Recovery (FIDVR) or at 0.88 p.u. & 10 seconds which conforms with the default setting of Category II I. UV2 could be set at 0.5 p.u. and 2 seconds which conforms with the default setting of Category III.

- 3) Develop standard frequency trip settings (1547-2018 Clause 6.5.1) that provide for BPS reliability. For example, use the default setting which were chosen to coordinate with under frequency load shedding.
- 4) Develop standard frequency droop settings (1547-2018 Clause 6.5.2.7) that provide for BPS reliability. For example, use the default settings that are consist with the requirements for generators connected to the BPS
- 5) Develop standard Enter Service settings (1547-2018 Clause 4.10) that can be used in black start studies. The default delay time is 300 seconds. However, distribution entities may require a shorter delay to reduce the impact of cold load pickup. Also, distribution entities may require different delay times when several large DER are connected to the same feeder
- 6) Develop requirements that ensure protective relay settings on the distribution system coordinate with the voltage and frequency ride-through capabilities established by the selected trip settings. Any exceptions shall be discussed with the transmission provider.

Appendix A, NPCC DER Impact Reporting Form and Process



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

Please Complete and email this form and email to; npccstandard@npcc.org

Distributed Energy Resource (DER), BES Impact Reporting Form

Name		Date	
Email		Company	
Impact on Bulk Electric System		Area (NY, NE, State or Province etc.)	

Equipment Impacted

Equipment	Location (substation name, etc.)	Impact (Positive reliability impact? Negative reliability impact-Protection System failure, Misoperation, load affected or lost?, power quality issue?, etc.)	Duration of Impact, (start and stop times, length of impact, ongoing? etc.)

Description of Impact on BES- What Happened or was observed?

Please describe below the details of all the impacts of the DER as it pertains to this report, such as load loss, loss of life, equipment failure or potential reliability improvement. A sequence of events showing the impact is helpful. Attach supporting information to this form if necessary.

Root Cause or additional Analysis

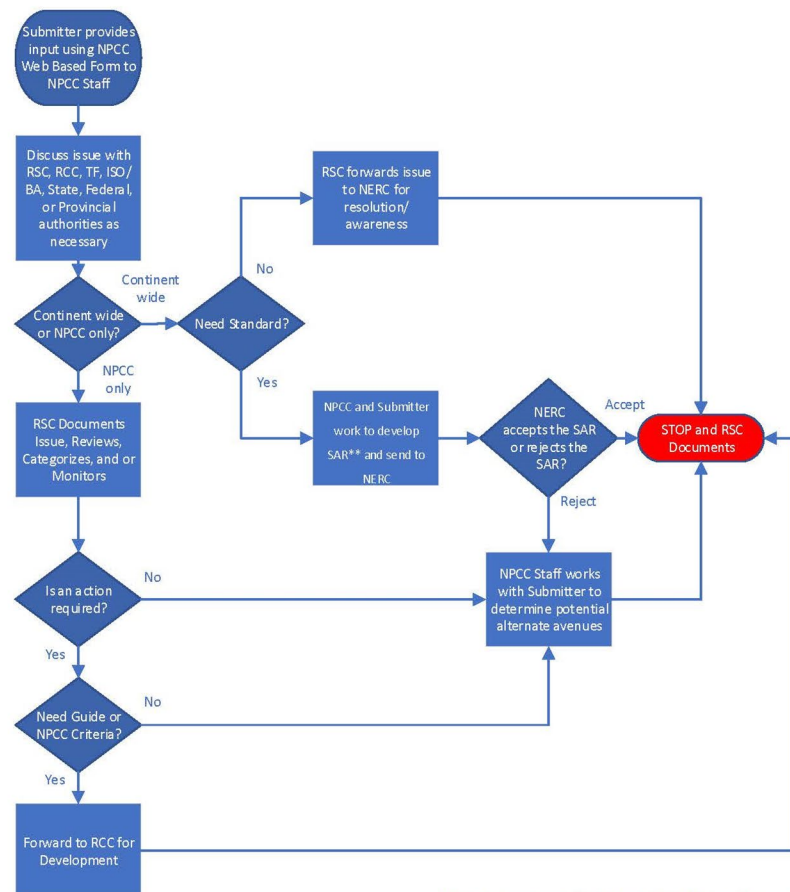
Please describe below the details of any investigation your company may have already done to identify causes or contributing factors to the incident. This will help NPCC route the issue properly to address it.

NPCC Review of Issue and Recommendations (i.e. refer to NERC, develop a Criteria, Guideline, Already Addressed or Identified, etc.)

NPCC Date of Resolution of Issue _____

Evaluation Process

Impacts from Distribution Level* Distributed Energy Resources on the BES



*Distribution Level, Not behind the Meter, utility scale DER

** Standards Authorization Request (SAR)

Regional Standards Committee, Approved 8/22/18 (GVZ)

Appendix B, NPCC Areas-Comparisons

Key Inverter based specification extracts

	ISO-NE Inverter Requirements	NG ESB 756 B, C, D	NY SIR ²⁹	IESO F2 Technical Requirements
Inverter Certification	yes	yes	yes	yes
Voltage and frequency trip settings for inverter-based applications	yes	yes	yes	yes
Voltage Response	yes ³⁰	yes	yes	yes
Frequency Response	yes ³¹		yes	yes
Abnormal performance capability (ride-through) requirements for inverter-based applications	yes	yes		
Other grid support utility interactive inverter functions statuses	yes			
Minimum protection functions		yes	yes	
Monitoring and Control		yes	yes	yes
Reconnection to the System		yes	yes	
Distribution Protection Coordination		yes		yes
Inverter Certification		yes	yes	
Power Quality			yes	

²⁹ NY SIR is the [New York Standardized Interconnection Requirement](#).

³⁰ The functionality is required to be present, but the default state is to have this functionality disabled unless otherwise directed by the area EPS operator

³¹ The functionality is required to be present, but the default state is to have this functionality disabled unless otherwise directed by the area EPS operator

Appendix C – SPIDER Working Group Reliability Guidelines & Activities

The NERC System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) was formed to focus on the impacts that aggregate amounts of DER can have on transmission planning and BPS reliability. This SPIDERWG is seeking to provide high-level, technical recommended practices for ensuring BPS reliability in the face of growing penetrations of DER across North America. The recommended practices and guidance provided by SPIDERWG, in many cases, will need to be adapted to specific utility and regional planning and operating practices. The following DER-related topics are covered, as described in NERC Staff's "Summary of Activities: BPS-Connected Inverter-Based Resources and Distributed Energy Resources"³²:

Modeling: Representing aggregate DER in BPS reliability studies, advancing industry capabilities and expertise with representing DER in these reliability studies, developing robust and reasonable data sets for power flow and dynamic simulations

Verification: Ensuring that the models used in studies provide a reasonable and suitable representation of the actual aggregate performance of these resources, benchmarking software platforms to ensure uniformity in tools, recommending analysis techniques for accounting for aggregate DER during large BPS disturbances

Studies: Improving study techniques and methods to ensure the most stressed operating conditions are chosen for BPS reliability studies, identifying key operating conditions and sensitivities to perform, improving software tools and study capabilities

Coordination: Supporting coordination between transmission and distribution entities for improved data exchange and coordinating with IEEE to support the application of IEEE Std. 1547- 2018 across North America

A list of SPIDERWG Reliability Guidelines and other activities is provided in Table 1 and Table 2, respectively.

³² Available here: https://www.nerc.com/comm/PC/Documents/Summary_of_Activities_BPS-Connected_IBR_and_DER.pdf

Table 1. SPIDER Working Group Reliability Guidelines

Subgroup	Title	Description	Status
Modeling	DER Data Collection for Modeling	Guideline providing recommended practices for collecting DER data for the purpose of developing aggregate DER models for BPS reliability studies.	In Review – Draft Posted for Comment (here)
	DER_A Model Parameterization	Guideline providing recommendations for using state-of-the-art aggregate DER dynamic models in BPS reliability studies.	Published (here)
Verification	DER Performance and Model Verification	Guideline providing recommended practices for performing model verification for aggregate DER dynamic models including placement of measurement devices, execution of verification simulations, and how to use the data collected through these practices.	In Development
	DER Forecasting Practices and Relationship to DER Modeling for Reliability Studies	Guideline providing how forecasting practices are linked to DER modeling for reliability studies, specifically on how DER are accounted for in future reliability assessments.	In Development
Studies	Bulk Power System Planning under Increasing Penetration of Distributed Energy Resources	Guideline providing recommended practices for performing planning studies considering the impacts of aggregate DER behavior.	In Development
	Recommended Approaches for Developing Underfrequency Load Shedding Programs with Increasing DER Penetration	Guideline regarding how to study UFLS programs and ensure their effectiveness with increasing penetration of DER.	Under Consideration
Coordination	BPS Reliability Perspectives on the Adoption of IEEE 1547-2018	Guideline providing industry recommendations and BPS reliability perspectives on the implementation and adoption of IEEE 1547-2018.	Published (here)
	Communication and Coordination Strategies for Transmission Entities and Distribution Entities regarding Distributed Energy Resources	Guideline recommending strategies to encourage coordination between Transmission and Distribution entities on issues related to DER such as information sharing, performance requirements, DER settings, etc.	In Development

Table 2. SPIDER Working Group Other Activities

Subgroup	Title	Description	Status
Modeling	Modeling Notification: Dispatching DER off Pmax in Case Creation	Notification of accounting for DER in powerflow and dynamics cases, particularly regarding accounting for power output levels with DER utilizing advanced grid-supportive features.	Posted (here)
	DER Modeling Survey	Survey of SPIDERWG member organizations regarding the use of DER models in BPS planning studies.	Compiling Results
Studies	White Paper: Review of TPL-001-5 for Incorporation of DER	White paper discussing technical review of NERC TPL-001-5 in the context of increasing DER and their impacts to the BPS. Possible SAR development following completion of white paper, as needed.	In Review
	White Paper: Recommended Simulation Improvements and Techniques	White Paper recommending simulation software improvements to enhance the ability to accurately account for and model DER.	In Development
	White Paper: DER Impacts to Undervoltage Load Shedding	White Paper briefly discussing how DER may impact UVLS program development.	In Development
	White Paper: Beyond Positive Sequence RMS Simulations for High DER	White Paper highlighting the use of tools that provide additional technical detail to DER studies beyond just positive sequence RMS simulation tools.	In Development
Coordination	Coordination of DER Terminology	Development and ongoing review of definitions and terminology pertaining to DER and related topics.	In Development
	NERC Reliability Standards Review	White Paper reviewing NERC Reliability Standards and the impacts that increasing penetrations DER may have on BPS reliability and standards compliance/implementation. Possible SAR development following completion of white paper, as needed.	In Development
	Tracking and Reporting DER Growth	Coordinated review of information regarding DER growth, including types of DER, size of DER, etc. Consideration for useful tracking techniques for modeling and reliability studies.	In Development

Appendix D, NPCC Reliability Principles

Using its membership structure and governance authority to create and apply Regional Criteria³³, NPCC Member adherence to Regional Criteria contributes to a more robust level of reliability beyond NERC ERO reliability “results-based” standards / requirements. For example, NPCC Criteria mandate specific design requirements for NPCC Member facilities. NPCC’s approach to reliability and Resilience can be summarized in Principles that guide NPCC Members in their effort to meet or exceed NERC requirements. NPCC’s core Reliability Principles³⁴ and activities support the NERC Bulk Electric System and NPCC’s Bulk Power System reliability.

The NPCC Reliability Principles include:

1. **Focus on the most important system components:** In order to focus resources to those portions of the power delivery system most important (critical) to overall reliability, NPCC Members employ mechanism(s) for identifying those facilities that are most critical to the reliable planning and operation of the power delivery assets in the NPCC region³⁵. These critical facilities collectively are identified as the NPCC Bulk Power System^{36,37}.
2. **Application of Criteria beyond NERC requirements to identified critical facilities:** Where, in the opinion of NPCC’s Membership, the NERC standards do not adequately specify a necessary performance or design outcome in a given technical, operation or planning area, NPCC Criteria govern the design of their respective portions of the NPCC Bulk Power System planning and operation³⁸ activities.
3. **NPCC Members support the Criteria:** NPCC’s Full Members in accordance with the NPCC Bylaws are committed to designing and operating their systems to meet the NPCC Criteria under peer review of the NPCC Full Members.
4. **No conflict with NERC Requirements:** The NPCC Criteria supplement, improve upon where necessary, benefit, and do not conflict with or duplicate the results-based performance

³³ See NERC Rule of Procedure #313 on page 15 of the [NERC Rules of Procedure 3-9-2018](#).

³⁴ The Reliability Principles were summarized in the NPCC 2018 Strategic Review Report.

³⁵ The method of identifying critical facilities is currently embodied in the [NPCC A-10 Classification of bulk power system Elements](#) document, currently under review by the CP-11 Working Group with a due date of October 31, 2018.

³⁶ The NPCC bulk power system is identified by a specific list of facilities in the NPCC region deemed critical by the NPCC A-10 classification process. This list is not determined based on the definition of the ERO bulk power system, which is defined in the US 2005 EPACT as:

“(A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and

“(B) electric energy from generation facilities needed to maintain transmission system reliability.

The term does not include facilities used in the local distribution of electric energy.

³⁷ There are other documents which supplement the Directories, for instance the NPCC Compliance Guidance Statements. These documents usually refer to NERC standards applicability and can be found here: [NPCC CGS](#)

³⁸ NERC [Rule of Procedure](#) #313 (page 15) permits the following: “Regional Entities may develop Regional Criteria that are necessary to implement, to augment, or to comply with NERC Reliability Standards, but which are not Reliability Standards. Regional Criteria may also address issues not within the scope of Reliability Standards, such as resource adequacy. “

requirements of NERC standards where they apply to the NPCC Bulk Power System. NPCC adjusts its Regional Criteria to retire or adapt to any new NERC requirements as they come into effect as necessary.

5. **Include design specifications where needed:** The NPCC Criteria and related guidelines and procedures provide design criteria and practices to assure implementation. NPCC Directories go into greater detail regarding how to accomplish a given reliability result, where NERC standards may simply require a “reliability result.”
6. **Resilience has always been an element of NPCC Criteria:** Based on experience, resilience^{39 40} is a necessary constituent component of reliability and it is important both to electricity consumers and regulatory authorities in NPCC’s Region. NPCC Criteria provide substantial resilience benefits to the NPCC Bulk Power System by providing:
 - a. Robustness – The ability to withstand disturbances by supporting operations in a more secure state.
 - b. Resourcefulness – The ability to detect and manage a crisis as it unfolds.
 - c. Rapid recovery – The ability to get services back as quickly as possible in a coordinated and controlled manner.
 - d. Adaptability – The ability to absorb new lessons from events

³⁹ Reference NERC’s recent [filing](#) with FERC regarding Resilience for a more complete discussion of the relationship between resilience, the NERC standards and the NAICS Resilience Framework. FERC is expected to define resilience in the course of its current examination of electric system resilience concepts.

⁴⁰In the US, [Presidential Policy Directive – 21](#) defines resilience as “The ability to prepare for and adapt to changing conditions and withstand and recover rapidly from disruptions. Resilience includes the ability to withstand and recover from deliberate attacks, accidents, or naturally occurring threats or incidents”.

NERC, Model of Resilience

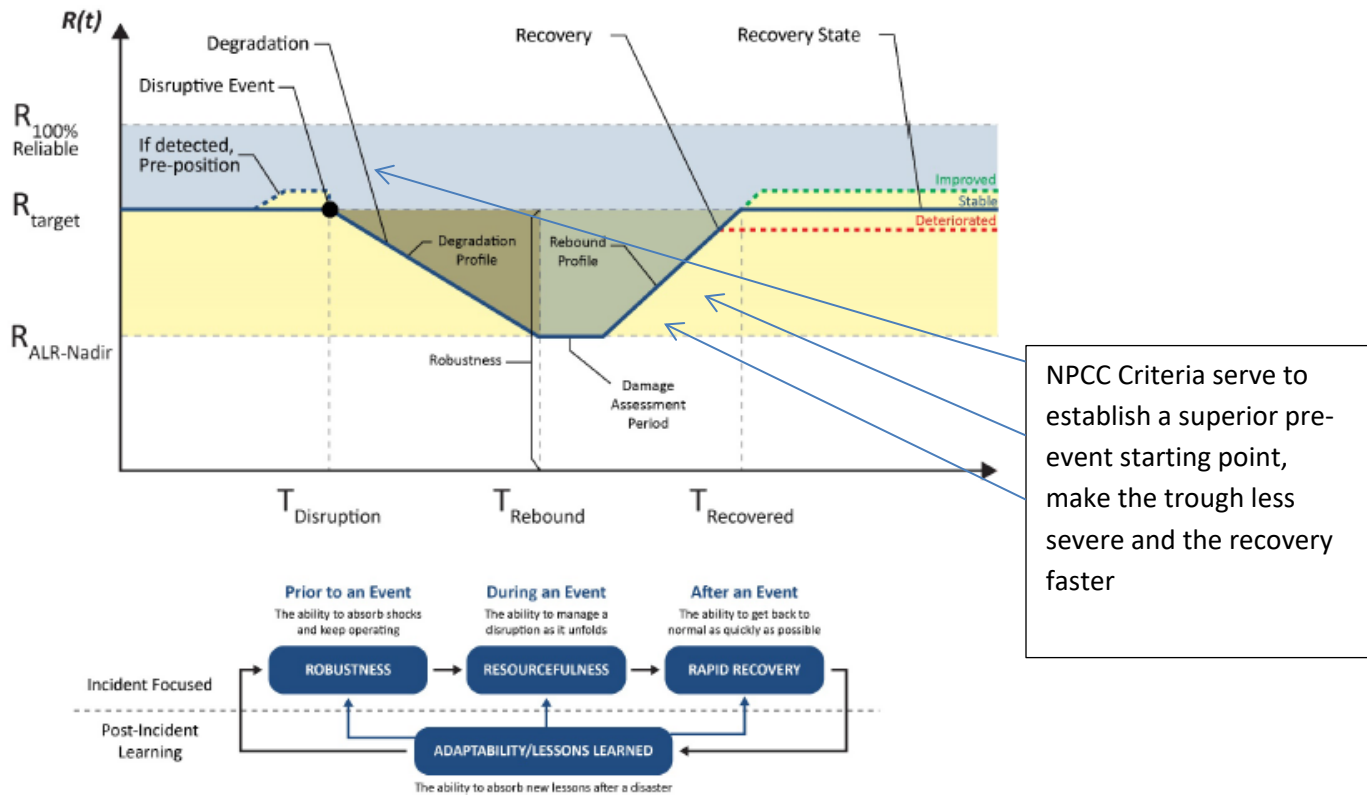


Figure 2.1

Figure 2.1 depicts a typical disruptive event and maps how the systems responds in a qualitative fashion. The y-axis above is meant to represent a relative level of reliability and system response is plotted temporally. DER will increasingly fill a critical role with respect to reliability and Resilience of the Bulk Electric System. Specifically, DER can contribute to the overall robustness of the system and provide increased resource support within islands during system separations. As DER continues to penetrate the system, changes to NPCC's Underfrequency Load Shedding program may be required.

Appendix E, State and Provincial AGIR Information

New York State

Statewide Interconnection Technical Documents may be found at:

[Interconnection Technical Working Group Webpage](#)

New England, by State

Inverter Source Requirement Document of ISO New England (ISO-NE)

Connecticut –

Department of Energy and Environmental Protection, Public Utilities Regulatory Authority (PURA)

Eversource Energy – Connecticut Interconnection Standard

<https://www.eversource.com/content/general/about/about-us/doing-business-with-us/builders-contractors/interconnections/connecticut-application-to-connect>

Summary of Facility Connection Requirements for Generation, Transmission and End Users Connecting to UI Transmission Facilities, Revision 4.0, December 7, 2015:

<https://www.uinet.com/wps/wcm/connect/89138d72-c4a0-403b-9871-937a00f91c42/NERC%2BFAC-001%2BInterconnect%2Bsummary%2BDocument%2BRevision%2B4.pdf?MOD=AJPERES&CACHEID=ROOTWORKSPACE-89138d72-c4a0-403b-9871-937a00f91c42-mkr0qCb>

Eversource/United Illuminating Guidelines for Generator Interconnection, Fast Track and Study Processes, April 5, 2019:

https://www.uinet.com/wps/wcm/connect/bd802aec-1e83-4051-8a6e-58f0cb98d1fd/Guideline_for_Generator_Interconnection_Fast_Track_and_Study_Process_5-12-10_doc_1577.pdf?MOD=AJPERES&CACHEID=ROOTWORKSPACE-bd802aec-1e83-4051-8a6e-58f0cb98d1fd-miUZQ4n

Maine –

Maine Public Utilities Commission

Chapter 324 Small Generator Interconnection Procedures

Central Maine Power Transmission and Distribution Interconnection Requirements for Generation, December 15, 2018:

<https://www.cmpco.com/wps/wcm/connect/dee5fbf1-7af0-40ec-b06c-af3ec015e0be/SchB-TransmissionDistributionInterconnectionRequirementsforGeneration.pdf?MOD=AJPERES&CACHEID=ROOTWORKSPACE-dee5fbf1-7af0-40ec-b06c-af3ec015e0be-mwfmMCK>

Emera Maine Interconnection Agreement:

<https://www.emeramaine.com/energy-solutions/connecting-renewable-resources/small-generator-interconnection-process/>

Massachusetts –

MA Department of Public Utilities (MADPU) interim guidance (DPU 19-55)

MADPU Massachusetts Department of Energy Resources

MADPU Interconnecting Renewable Energy webpages with links to: resources, past and present proceedings before the DPU, each electric distribution companies' tariff, and the Ombudsperson dispute resolution process: <https://www.mass.gov/interconnecting-renewable-energy-facilities>

MADPU is currently conducting a large-scale investigation into the rules and procedures by which distributed generation is interconnected in Massachusetts in docket D.P.U. 19-55. This investigation includes implementation of IEEE 1547-2018. Documents and information can be found in our online file room: <https://eeaonline.eea.state.ma.us/DPU/Fileroom/dockets/bynumber> (enter "19-55")

Massachusetts Technical Standards Review Group:
<https://sites.google.com/site/massdgic/home/interconnection/technical-standards-review-group>

Renewable energy generally: <https://www.mass.gov/topics/renewable-energy>

MADPU Net Metering Information: <https://www.mass.gov/net-metering>

MADOER SMART Program Information: <https://www.mass.gov/info-details/solar-massachusetts-renewable-target-smart-program>

Who to contact in MA for your renewable energy question: <https://www.mass.gov/info-details/who-to-contact-about-my-renewable-energy-question-or-concern>

Massachusetts Utilities

National Grid / Supplement to Specifications for Electrical Installations / ESB 756-2019 ver. 5.0 (Section 7.8 includes voltage and frequency ride through and control requirements);

https://www9.nationalgridus.com/non_html/shared_constr_esb756.pdf

NSTAR ELECTRIC COMPANY d/b/a EVERSOURCE ENERGY STANDARDS FOR INTERCONNECTION OF DISTRIBUTED GENERATION, M.D.P.U. No. 55, Effective: February 1, 2018:

https://author.eversource.com/content/docs/default-source/rates-tariffs/ma-electric/55-tariff-ma.pdf?sfvrsn=8582c462_6

Unitil Energy Systems, Inc. Interconnection Standards for Inverters Sized up to 100 kVA:

https://unitil.com/sites/default/files/pdfs/UES%20100%20KVA%20Interconnect%20Standard%202009_08_21_1.pdf

Individual Massachusetts Municipal Electric Utility Entity Interconnection Requirements:

<https://www.mass.gov/guides/net-metering-guide>

New Hampshire –

New Hampshire Public Utilities Commission

Liberty Utilities Electricity Delivery Service Tariff – NHPUC No. 20:

https://www.puc.nh.gov/Regulatory/Docketbk/2018/18-183/INITIAL%20FILING%20-%20PETITION/18-183_2018-12-10_GSEC_TARIFF.PDF

New Hampshire Electric Co-op Net Metering Requirements:

<https://www.nhec.com/wp-content/uploads/2017/02/2017-Interconnection-Application-Package.pdf>

Public Service Company of New Hampshire Interconnection Standards for Inverters Sized Up to 100 KVA, August 2009:

https://www.eversource.com/content/docs/default-source/builders-contractors/eversource's-interconnection-standards-for-inverters.pdf?sfvrsn=2dd9cf62_0

Unitil Energy Systems, Inc. Interconnection Standards for Inverters Sized up to 100 kVA:

https://unitil.com/sites/default/files/pdfs/UES%20100%20KVA%20Interconnect%20Standard%202009_08_21_1.pdf

Rhode Island –

State of Rhode Island Public Utilities Commission and Division of Public Utilities and Carriers

Block Island Power Company Net Metering Application:

<https://blockislandpowercompany.com/net-metering-application-2/>

The Narragansett Electric Company Standards for Connecting Distributed Generation, Effective September 6, 2018:

https://www9.nationalgridus.com/non_html/RI_DG_Interconnection_Tariff.pdf

Pascoag Utility District – Electric Net Metering Policy, Requested Effective Date: June 1, 2010:

<https://www.pud-ri.org/wp-content9999/uploads/2015/07/Net-Metering-Policy.pdf>

Vermont –

Vermont Public Utility Commission

The Vermont Public Utility Commission issued an interconnection rule in 2006 that was largely modeled on the FERC Small Generator Interconnection Procedures at that time. The rule has not been updated since 2006.

Links to the current rule as well as an application form and application instructions:

PUC Rule 5.500 – Interconnection Rule

https://puc.vermont.gov/sites/psbnew/files/doc_library/5500-electric-generation-interconnection-procedures_0.pdf

PUC Rule 5.500 – Application Form

https://puc.vermont.gov/sites/psbnew/files/doc_library/5500-revised-application_0.pdf

PUC Rule 5.500 – Application Instructions

https://puc.vermont.gov/sites/psbnew/files/doc_library/5500-revised-application-instructions_0.pdf

In addition, the Department petitioned the PUC to initiate a rulemaking to make adjustments to the interconnection rule in 2016. As of the date of this DER Guidance document there were some filings and a workshop, but the process recently ended without resolution. The PUC has indicated that they are likely to take up the process again in the near future however has not provided NPCC with a date. Information regarding this process can be found here: <https://puc.vermont.gov/about-us/statutes-and-rules/proposed-changes-rule-5500>

Province of Quebec (some references are only available in French)

Section 112 of the [Act respecting the Régie de l'énergie](#) (chapter R-6.01) (the Act) reads as follows:

112. THE GOVERNMENT MAY MAKE REGULATIONS DETERMINING

[...]

(2.1) *for a particular source of electric power supply, the corresponding energy block and maximum price established for the purpose of fixing the cost of electric power referred to in section 52.2 or for the purposes of the supply plan provided for in section 72, or for the purposes of a tender solicitation by the electric power distributor under section 74.1;*

(2.2) *the timeframe applicable to a public tender solicitation by the electric power distributor under section 74.1;*

(2.3) *the maximum production capacity referred to in section 74.3, which may vary with the source of renewable energy or the class of customers or producers specified;*

[...]

In cases where energy needs are to be supplied out of an energy block, a regulation may provide that only certain classes of suppliers may be invited to tender by the electric power distributor and that the quantity of electric power required under each supply contract may be limited.

Consequently, the Government has taken the following regulations, regarding Distributed Energy Resources (or DER), between 2003 and 2013:

- [CONCERNANT le Règlement sur l'énergie produite par cogénération](#) (Décret 1319-2003, 10 décembre 2003);
- [CONCERNANT le Règlement sur l'énergie éolienne et sur l'énergie produite avec de la biomasse](#) (Décret 352-2003, 5 mars 2003);
- [CONCERNANT le Règlement modifiant le Règlement sur l'énergie produite par cogénération](#) (Décret 298-2004, 29 mars 2004);
- [CONCERNANT le Règlement sur le second bloc d'énergie éolienne](#) (Décret 926-2005, 12 octobre 2005);
- [CONCERNANT le Règlement sur l'énergie produite par cogénération à la biomasse](#) (Décret 916-2008, 24 septembre 2008);
- [CONCERNANT le Règlement sur un bloc de 250 MW d'énergie éolienne issu de projets autochtones](#) (Décret 1043-2008, 29 octobre 2009);
- [CONCERNANT le Règlement sur un bloc de 250 MW d'énergie éolienne issu de projets communautaires](#) (Décret 1045-2008, 29 octobre 2008);
- [CONCERNANT le Règlement modifiant le Règlement sur l'énergie produite par cogénération à la biomasse](#) (Décret 9-2009, 7 janvier 2009);
- [CONCERNANT le Règlement modifiant le Règlement sur un bloc de 250 MW d'énergie éolienne issu de projets communautaires](#) (Décret 179-2009, 4 mars 2009);
- [CONCERNANT le Règlement modifiant le Règlement sur un bloc de 250 MW d'énergie éolienne issu de projets autochtones](#) (Décret 180-2009, 4 mars 2009);
- [CONCERNANT le Règlement sur la capacité maximale de production visée dans un programme d'achat d'électricité pour des petites centrales hydroélectriques](#) (Décret 336-2009, 25 mars 2009);
- [CONCERNANT le Règlement modifiant le Règlement sur un bloc de 250 MW d'énergie éolienne issu de projets autochtones](#) (Décret 520-2009, 29 avril 2009);
- [CONCERNANT le Règlement modifiant le Règlement sur un bloc de 250 MW d'énergie éolienne issu de projets communautaires](#) (Décret 521-2009, 29 avril 2009);
- [CONCERNANT le Règlement modifiant le Règlement sur un bloc de 250 MW d'énergie éolienne issu de projets communautaires](#) (Décret 468-2010, 2 juin 2010);
- [CONCERNANT le Règlement modifiant le Règlement sur un bloc de 250 MW d'énergie éolienne issu de projets autochtones](#) (Décret 469-2010, 2 juin 2010);
- [CONCERNANT le Règlement sur la capacité maximale de production visée dans un programme d'achat d'électricité produite par cogénération à base de biomasse forestière résiduelle](#) (Décret 1085-2011, 26 octobre 2011);
- [CONCERNANT le Règlement sur un bloc de 450 mégawatts d'énergie éolienne](#) (Décret 1149-2013, 6 novembre 2013).

The following regulations, or modified regulations (marked in yellow highlight in the section above) have led to four tender solicitations, targeting precise quantities, or energy blocks, of wind Energy:

- [CONCERNANT le Règlement sur l'énergie éolienne et sur l'énergie produite avec de la biomasse](#) (Décret 352-2003, 5 mars 2003);

- [CONCERNANT le Règlement sur le second bloc d'énergie éolienne](#) (Décret 926-2005, 12 octobre 2005);
- [CONCERNANT le Règlement modifiant le Règlement sur un bloc de 250 MW d'énergie éolienne issu de projets communautaires](#) (Décret 468-2010, 2 juin 2010);
- [CONCERNANT le Règlement sur un bloc de 450 mégawatts d'énergie éolienne](#) (Décret 1149-2013, 6 novembre 2013).

The Régie considers the results of these tenders when examining Hydro-Québec's supply plan, as per section 72 of the Act:

***72.** With the exception of private electric power systems, a holder of exclusive electric power or natural gas distribution rights shall prepare and submit to the Régie for approval, according to the form, tenor and intervals fixed by regulation of the Régie, a supply plan describing the characteristics of the contracts the holder intends to enter into in order to meet the needs of Québec markets following the implementation of the energy efficiency measures. The supply plan shall be prepared having regard to*

- (1) the risks inherent in the sources of supply chosen by the holder;*
- (2) as concerns any particular source of electric power, the energy block established by regulation of the Government under subparagraph 2.1 of the first paragraph of section 112; and*

[...]

When examining a supply plan for approval, the Régie shall consider such economic, social and environmental concerns as have been identified by order by the Government.

Sections 74.1 and 74.2 of the Act provide that the Régie oversees the process of such tender solicitations:

***74.1.** To ensure that suppliers responding to a tender solicitation are treated with fairness and impartiality, the electric power distributor shall establish and submit for approval to the Régie, which shall make its decision within 90 days, a tender solicitation and contract awarding procedure and a tender solicitation code of ethics applicable to the electric power supply contracts required to meet the needs of Québec markets in excess of the heritage pool, or the needs to be supplied out of an energy block determined by regulation of the Government under subparagraph 2.1 of the first paragraph of section 112.*

The tender solicitation and contract awarding procedure shall, in particular,

- (1) allow all interested suppliers to tender by requiring the tender solicitation to be issued in due time;*
- (2) grant equal treatment to all sources of supply and energy efficiency projects unless the tender specifications provide that all or part of the needs met by a particular source of supply must be supplied out of an energy block determined by regulation of the Government;*
- (3) favour the awarding of supply contracts based on the lowest tendered price for the required quantity of electric power and in keeping with the required conditions, taking into account the applicable transmission cost and, where the tender specifications provide that all or part of the needs met by a particular source of supply must be supplied out of an energy block, taking into account the maximum price established by regulation of the Government; and*
- (4) provide that, following a tender solicitation, contracts may be awarded to two or more suppliers, in which case a supplier offering the required quantity of electric power may be invited to reduce the quantity offered without modifying the tendered unit price.*

An energy efficiency project to which a tender solicitation applies under subparagraph 2 of the second paragraph must meet the stability, sustainability and reliability requirements that apply to conventional sources of supply.

The Régie may dispense the electric power distributor from soliciting tenders for short-term contracts or where urgent needs must be met.

For the purposes of this section, the promoter of an energy efficiency project is deemed to be an electric power supplier.

74.2. *The Régie shall monitor the implementation of the tender solicitation and contract awarding procedure and code of ethics provided for in section 74.1 and ascertain whether they are complied with. To that end, the Régie may require any document or information it considers useful. The Régie shall report its findings to the electric power distributor and to the supplier chosen.*

The electric power distributor may not enter into an electric power supply contract unless it has obtained the approval of the Régie, under the conditions and in the cases determined by regulation by the Régie.

The Régie's Website lists every docket related to this jurisdiction over Québec's electricity distributor (in French only): [Approval of supply contracts](#).

The Régie also considers DER when adopting specific reliability standards. Sections 85.2 and 85.7 of the Act read as follows:

85.2. *The Régie shall ensure that electric power transmission in Québec is carried out according to the reliability standards it adopts.*

85.7. *The Régie may request the reliability coordinator to modify a standard filed or submit a new one, on the conditions it sets. It shall adopt reliability standards and set the date of their coming into force.*

The reliability standards may

- (1) subject to section 85.10, provide for a schedule of sanctions, including financial penalties, that apply if standards are not complied with; and*
- (2) refer to reliability standards set by a standardization agency that has entered into an agreement.*

Docket [R-4070-2018](#) (in French only) relates to a request by the reliability coordinator (HQCME) and is still under examination by the Régie. It aims the adoption of reliability standards associated with Special Protection System (Remedial Action Scheme) and Dispersed Power Producing Resources.

The following sections of Québec' electricity distributor and transmitter's web site might be useful, since they list the applicable technical codes, standards and requirements:

- http://www.hydroquebec.com/transenergie/fr/commerce/raccordement_distribution.html ;
- http://www.hydroquebec.com/transenergie/fr/commerce/raccordement_transport.html

Province of Ontario

The current connection requirements for all resources can be found in Chapter 4 appendices 4.2 and 4.3 of the Market Rules. <http://www.ieso.ca/-/media/Files/IESO/Document-Library/Market-Rules-and-Manuals-Library/market-rules/mr-chapter4appx.pdf?la=en>

The Independent Electric System Operator (IESO) is in the process of making updates to these requirements to be more specific about the requirements that apply to all DERs (not just storage). <http://www.ieso.ca/Sector-Participants/Engagement-Initiatives/Engagements/Updates-to-Performance-Requirements-Market-Rule-Appendices-4-2-and-4-3>

The IESO is working on several white papers. The one that was posted in 2019 called “**Exploring Expanded DER Participation in the IESO-Administered Markets**” sets out the participation models that exist for DER in wholesale markets in general and in the IESO-Administered Markets (IAM) today and

also identify the range of options that exist for expanded participation in the future. In addition, this paper provides a working definition of DER, sets out principles for integrating them into wholesale markets, offers an initial review of participation models in other jurisdictions, and identifies key barriers that may limit DER participation in the IAMs.

<http://www.ieso.ca/-/media/Files/IESO/Document-Library/White-papers/White-paper-series-Conceptual-Models-for-DER-Participation.pdf?la=en>

The Ontario Energy Board is also engaging in several stakeholder activities in this area. Below are the links to those activities. The Ontario Energy Board has combined the first two initiatives into one engagement.

1. **Responding to Distributed Energy Resources (DER)*** - The purpose of this initiative is to develop a more comprehensive regulatory framework that facilitates investment and operation of DER based-on value to consumers and supports effective DER integration so the benefits of sector evolution can be realized.

<https://www.oeb.ca/industry/policy-initiatives-and-consultations/responding-distributed-energy-resources-ders>

2. **Utility Remuneration*** - The purpose of this initiative is to identify how to remunerate utilities in ways that make them indifferent to traditional or innovative solutions, better supports their pursuit of least cost solutions, strengthens their focus on long-term value and requires them to reflect the impact of sector evolution in their system planning and operations.

<https://www.oeb.ca/industry/policy-initiatives-and-consultations/utility-remuneration>

3. **DER Connections Review** – The purpose of this initiative to review its requirements regarding the connection of distributed energy resources (DER) by licensed electricity distributors. The purpose of this initiative is to identify any barriers to the connection of DER, and where appropriate to standardize and improve the connection process. The review will be focused on connection of electricity generation and storage facilities connected to the distribution system, either in front or behind the distributor's meter.

<https://www.oeb.ca/industry/policy-initiatives-and-consultations/distributed-energy-resources-der-connections-review>

The contact for this information would be Customer Relations (customer.relations@ieso.ca)

Province of New Brunswick

Within the province, DER is referred to as “Embedded Generation” or “Distributed Generation.”

Regulation from the New Brunswick Energy and Utility Board may be found here:

<http://laws.gnb.ca/en/ShowPdf/cs/2013-c.7.pdf>

Ènergie NB Power’s embedded generation may be found here:

<https://www.nbpower.com/en/products-services/embedded-generation/>

Appendix F, ISO New England

ISO-NE specific Inverter requirements are as follows in the below table and the link

[Inverter Source Requirement Document of ISO New England](#)

The following additional performance requirements are applied in one NPCC Area and are provided as an example:

- In the Permissive Operation region above 0.5 p.u., inverters shall ride-through in Mandatory Operation mode, and
- In the Permissive Operation region below 0.5 p.u., inverters shall ride-through in Momentary Cessation mode.

Table I: Inverters' Voltage Trip Settings

Shall Trip – IEEE Std 1547-2018 (2 nd ed.) Category II					
Shall Trip Function	Required Settings		Comparison to IEEE Std 1547-2018 (2 nd 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

Table II: Inverters' Frequency Trip Settings

Shall Trip Function	Required Settings		Comparison to IEEE Std 1547-2018 (2 nd 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

Table III: Inverters' Voltage Ride-through Capability and 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 (2 nd ed.) for Category II
$V > 1.20$	Cease to Energize	N/A	0.16	Identical
$1.175 < V \leq 1.20$	Permissive Operation	0.2	N/A	Identical
$1.15 < V \leq 1.175$	Permissive Operation	0.5	N/A	Identical
$1.10 < V \leq 1.15$	Permissive Operation	1	N/A	Identical

$0.88 \leq V \leq 1.10$	Continuous Operation	infinite	N/A	Identical
$0.65 \leq V < 0.88$	Mandatory Operation	Linear slope of 8.7 s/1 p.u. voltage starting at 3 s @ 0.65 p.u.: $T = 3 \text{ s} + \frac{8.7 \text{ s}}{V - 0.65 \text{ p.u.}}$ VRT 1 p. u.	N/A	Identical
$0.45 \leq V < 0.65$	Permissive Operation ^{a,b}	0.32	N/A	See footnotes a & b
$0.30 \leq V < 0.45$	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 can be used. Provided as an example:

- 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.

Table IV: Inverters' Frequency Ride-through Capability

Frequency Range (Hz)	Operating Mode	Minimum Time(s) (design criteria)	Comparison to IEEE Std 1547-2018 (2 nd ed.) for Category II
$f > 62.0$	No ride-through requirements apply to this range		Identical
$61.2 < f \leq 61.8$	Mandatory Operation	299	Identical
$58.8 \leq f \leq 61.2$	Continuous Operation	Infinite	Identical
$57.0 \leq f < 58.8$	Mandatory Operation	299	Identical
$f < 57.0$	No ride-through requirements apply to this range		Identical

Table V: Grid Support Utility Interactive Inverter Functions Status

Function	Default Activation State
SPF, Specified Power Factor	OFF ²
Q(V), Volt-Var Function with Watt or Var Priority	OFF Default value: 2% of maximum current output per second
SS, Soft-Start Ramp Rate	ON
FW, Freq-Watt Function OFF	OFF

Appendix G, State Renewable and Green Energy Targets

New York State

70% renewable energy by 2030
85% reduction of Greenhouse Gas emissions by 2050
6,000 MW of distributed solar by 2025
3,000 MW of energy storage by 2025
Carbon free electricity system by 2040

Connecticut

Carbon free electricity system by 2040
Renewable Portfolio Standard - <https://portal.ct.gov/PURA/RPS/Renewable-Portfolio-Standards-Overview>

Vermont

90% of Vermont's overall energy needs from renewable sources by 2050
Reduce Vermont's greenhouse gas (GHG) emissions by 50% from the 1990 baseline level by 2028, and by 75% from the 1990 level by 2050

New Hampshire

20% to 25% reduction in Greenhouse Gas emissions by 2032
25.2% renewable energy by 2025

Rhode Island

100% renewable energy by 2030
1,000 MW of new clean energy installed in 2020

Maine

80% renewable energy by 2030

Appendix H, Autonomous Energy Grids

The National Renewable Energy Laboratory (NREL) and its partners are conducting research and development of advanced techniques that would enable the optimization and control of hundreds of millions of deployed distributed energy resources (DER). The concept known as “Autonomous Energy Grids (AEGs)” are multi-layer, or hierarchical, cellular-structured power grid and control systems that enable resilient, reliability, and economic optimization⁴¹. Supported by a scalable, reconfigurable, and self-organizing information and control infrastructure, AEGs are extremely secure and resilient, and can operate in real time to ensure economic and reliable performance while systematically integrating energy in all forms. AEGs rely on cellular building blocks that can self-optimize when isolated from a larger grid and participate in optimal operation when interconnected to a larger grid. The figure H-1 shows how a scalable approach to control can be built from the lowest level of individual controllable technologies (renewable energy, conventional generation, electric vehicles, storage, and loads) and used to control hundreds of millions of devices through the use of hierarchical cells. To make this idea a reality, there are control algorithms for AEGs that will need to be developed and implemented with the following characteristics:

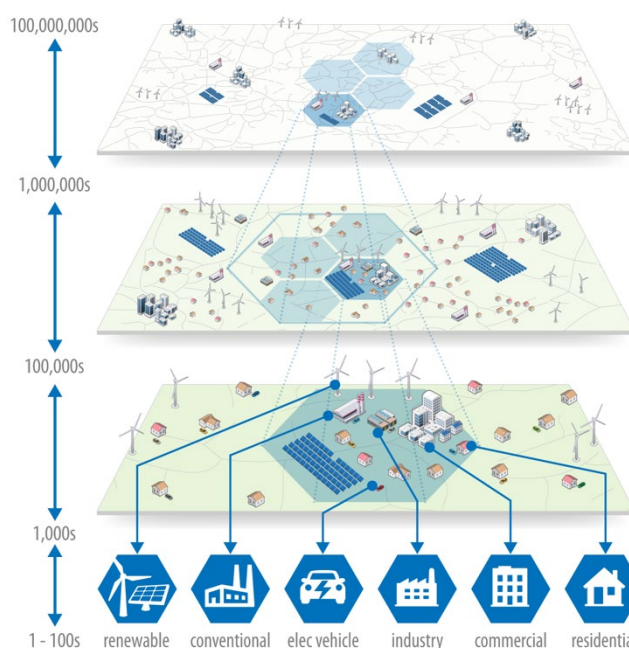


Figure H-1: Autonomous Energy Grids form a distributed hierarchical control system that integrated individual technologies in a cellular structure to the bulk power system.

- **Operate in Real Time** – Control algorithms must operate fast enough to ensure real-time operations in power grids that balance load and generation every second.
- **Handle Asynchronous Data and Control Actions** – Data needs to be used from a variety of asynchronous measurements and sources; whereas distributed decision-making leads to asynchronous control actions.
- **Robustness** – This covers both reliability and resilience, where reliability is fault tolerance and resilience are the ability to come back from a failed state. These control systems must also be

⁴¹ “Autonomous Energy Grids”, B. Kroposki, E. Dall’Anese, A. Bernstein, Y. Zhang, B. Hodge, Proceedings of the 51st Hawaii International Conference on System Sciences, January 2018, <https://scholarspace.manoa.hawaii.edu/bitstream/10125/50229/1/paper0342.pdf>

robust to communications failures, prolonged communications outages, and large-scale disturbances.

- **Scalable**— Control algorithms must operate in a scalable fashion to ensure control of hundreds of millions of devices.

NREL has evaluated the AEG algorithms on both large-scale laboratory testing and small-scale real-world demonstrations. NREL evaluated the algorithms as part of the DOE ARPA-E NODES program that demonstrated the first implementation of the algorithms in hardware and successfully demonstrate real-time optimization of a single AEG cell with more than 100 controllable devices at NREL's Energy Systems Integration Facility⁴². The experiment includes simulation of a real distribution feeder from California with 366 single-phase connection points, more than 100 controllable assets at power (inverters, electric vehicles, and batteries), and hundreds of simulated devices. The distributed algorithms were implemented in cost-effective microcontrollers that self-optimize and communicate to the central coordinator to attain system-wide goals (voltage regulation, frequency response).

NREL has also moved out of the lab to demonstrate the deployment of AEGs in the real world. The team has been working with Holy Cross Energy (HCE), a utility cooperative near Aspen, Colorado, to deploy the AEG technology in a group of smart homes in Basalt, CO⁴³. The smart homes in Basalt Vista are a pilot for an altogether new approach to the grid. These homes optimize energy for residents and their neighbors, but the principles behind Basalt Vista go much further. Within homes, each new connected device or energy resource like a residential battery, water heater, or solar photovoltaic (PV) system, can be controlled for unprecedented energy efficiency. And at a larger scale, entire communities could rapidly share power, creating reliable energy for everyone.

⁴² <https://www.nrel.gov/news/features/2019/from-the-bottom-up-designing-a-decentralized-power-system.html>

⁴³ <https://www.nrel.gov/news/features/2019/small-colorado-utility-sets-national-renewable-electricity-example-using-nrel-algorithms.html>

Appendix I, Transmission-Connected Inverter-Based Resources

There is presently rapid growth of large-scale transmission-connected inverter-based resource (IBR) capacity in the NPCC footprint, driven by public policy initiatives (e.g., NY Clean Energy Standard) as well as decreasing lifecycle cost of electricity (CoE) provided by these resources. Almost all of this transmission IBR capacity is variable energy resources (VER), comprised of wind and solar PV renewable generation or battery energy storage systems (BESS). The characteristics and performance of these resources will have an increasing impact on the security of the bulk power system that is further amplified by the displacement of conventional synchronous resources by the IBR.

The subject of the main body of this document is distributed energy resources; i.e., resources connected to the grid at the distribution level. There are many similarities between the characteristics and BPS security impacts of DER and transmission IBR, as well as many differences. This appendix summarizes key similarities and differences.

IBR Equipment and Facilities

Wind generation is infrequently deployed as DER but comprises a large portion of transmission IBR capacity. In the future, a substantial portion of the wind generation in the NPCC footprint will be offshore wind, which has some differences with onshore wind generators. Offshore wind units are much larger than onshore units (up to 15 MW compared to 3 MW for onshore). This is due to the high costs of the supporting structure in the offshore environment, and also due to the impracticality of transporting very large wind turbine components (e.g., blades, nacelles) over land to onshore locations. Planned offshore wind plants (> 1 GW) also tend to be very large compared to the onshore wind plants in the NPCC area. Offshore wind also has unique characteristics due to the undersea transmission lines that are part of the projects.

Inverters in transmission-connected solar PV and BESS facilities tend to be the same or similar to inverters used for DER applications, with scaling performed by using many inverters tied into a MV collection system to a substation stepping voltage to the transmission level. Frequently, these inverters have settings and characteristics that are more appropriate for distribution interconnections than transmission. Because these facilities in the US are generally owned by non-utility entities, they come under the jurisdiction of local electrical inspectors and the National Electric Code. The NEC requires electrical equipment to be “listed” such as by Underwriter’s Laboratory, and local electrical inspectors enforce compliance with this code. The only UL standard, in the past, for inverters is one based on the IEEE 1547 standard for distribution-connected resources, for which the previous 2003 version requires voltage and frequency tripping, and long delays on return to service, that are inappropriate for large-scale transmission resources. This has led to transmission IBR tripping inappropriately for otherwise benign transmission fault events, leading to significant frequency disturbances in the WECC and ERCOT systems. These events have been the subject of recent focused attention by NERC as an indication of a problematic situation that may become even more severe with greater DER penetration. Historically, wind generation has generally not experienced similar interference by local authorities in implementing good ride-through practices.

BPS Planning and Operational Performance Impacts

Displacement of Conventional Generation

Both DER, via reduction of net distribution load, and transmission-connected IBR will tend to displace conventional synchronous generation in the same manner. Because some IBR plants, such as offshore wind, are very large, the issues of system weakness may be encountered to a greater degree for transmission IBR. These system strength issues may result in control instabilities that negatively impact BPS security, and special detailed studies are warranted for low short-circuit ratio (grid strength relative to the rating of the IBR plant) situations.

Planning Models

Prevailing transmission interconnection practice requires transmission IBR developers to provide explicit models for their facilities. This is in contrast with DER, where an assortment of different DER devices, often without specific models available, are scattered about the topology of the distribution system. In the DER case, transmission planners must resort to generic approximations and equivalent distribution feeder models (i.e., a single effective distribution impedance) to represent DER in transmission studies. The detailed models and documentation routinely provided for transmission IBR projects results in much less uncertainty regarding the performance and impacts of these plants on the BPS, compared to the aggregate impacts of DER.

It has become increasingly relevant to evaluate performance issues of transmission IBR that cannot be correctly studied using typical fundamental-frequency phasor simulation tools (i.e., transient stability programs). This is particularly important in situations where the short-circuit ratio is low and various types of control instability are possible. Developer submission of electromagnetic transient (EMT) models for larger transmission IBR projects is becoming more common, as are detailed interconnection studies using these models for performance evaluation. This degree of modeling and study detail is generally infeasible at the distribution (DER) level.

Operational Visibility

Transmission-connected IBR plants are typically interconnected to the SCADA systems of the transmission system operator. This provides much greater operational visibility of these plants, compared to DERs which are frequently individually too small for telemetry requirements and are not visible to BPS operators.

Loss of Generation During Disturbances

Loss of generation during system voltage and frequency disturbances has the same impact whether DER or transmission IBR are tripped.

Stability

The impacts of transmission IBR and DER on system angular and frequency stability are virtually the same. A transmission-connected IBR, because its terminal voltage is not decoupled from the transmission system voltage like DER due to OLTC and distribution feeder voltage regulator action, can be more effective in mitigating BPS voltage stability issues using its dynamic reactive power capability.

Inadvertent Islands

The scale of transmission IBR generally supports more sophisticated protection and communication systems, such as implementation of transfer trip, that make inadvertent islands less of an issue for transmission IBR relative to DER.

Effective Grounding

The system grounding provided by transmission-connected IBR plants needs to be compatible with the transmission system. Typically, grounded-wye/grounded-wye plant step-up transformers with a delta tertiary are used, providing a ground source to both the transmission system and the plant's internal collection system.

Over-Generation

Overgeneration, from whatever the source, is a BPS operational concern. Because transmission IBR are routinely interconnected with the transmission system's SCADA, direct limitation of IBR plant output by the system operator is feasible.

System Restoration

Very few IBR plants today offer black-start capability. Variable IBR, such as wind and solar, should generally be kept off of the system during the early stages of restoration, assuming sufficient synchronous capacity exists. This avoids issues maintaining generation-load balance and also avoids weak-system control stability issues during the period when few synchronous generators are on line. This is made feasible due to the SCADA interconnection of these plants. BESS might be useful sources of capacity during restoration, but procedure should ensure that BESS using the more common grid-following control structure are not placed on line without sufficient system strength.

GMD Vulnerability

As the case for DER, transmission IBR are potentially vulnerable to the undervoltage tripping and misoperation due to harmonic voltage distortion during geomagnetic disturbances as are DER. A difference, however, is that an IBR's transformer is directly exposed to geomagnetic currents, if a grounded-wye transmission-side winding connection is used.

Power Quality

Properly designed IBR plants typically do not "inject" problematic levels of harmonic distortion into the transmission system. The inverters and other plant facilities can interact with the transmission system, however, to form resonances that can potentially result in severe amplification of ambient distortion present in the system from other sources. This resonance issue is particularly an issue for offshore wind plants interconnected using ac cables. The large charging capacitances of long undersea cables can interact with the transmission system to cause very severe lightly-damped resonances. In addition to power quality issues of increased voltage distortion, these resonances can be stimulated by transient events such as faults or switching that can cause substantial overvoltages in the transmission system. Detailed evaluation of harmonic performance is warranted for large IBR projects, and particularly those using long undersea ac cables.

Resource Planning Impacts

Forecasting Capacity

The longer term forecasting of installed IBR capacity is dictated by economics and policy, in the same manner as DER except that the decisions of large IBR developers will be based on economic factors (subsidies and tax credits considered) whereas the installation of small-scale DER by individual utility customers may also include other non-economic factors (e.g., “green statement”, keeping up with neighbors). Thus, the longer-term transmission IBR forecast may be more straightforward than one of future DER capacity.

The shorter-term forecast for transmission IBR capacity is driven by the interconnection queue. System planners have generally become experienced in determining the amount of in-queue capacity that will actually be built. DER interconnection is a much faster process, and the interconnection queue does not reveal as much useful information regarding future capacity.

Resource Adequacy

Because transmission IBR output is directly monitored, the statistical probability of output coincident with system needs for various types of IBR facilities can be assessed from historical data. While this process has uncertainty, the detailed information on temporal performance provides a much better basis for evaluating contribution to system capacity than is the case for unmonitored DER.

Concentration of a large amount of variable energy resources of one type in one geographic region can diminish the incremental capacity value that the resource provides. Within NPCC, a large amount of offshore wind generation capacity is planned for the New York Bight area of the Atlantic Ocean, interconnecting to both the NYISO and ISO-NE systems. There will also be a significant amount of PJM-connected offshore wind in the same area. A resource adequacy concern is that meteorological conditions in this area could greatly reduce the available generation from these offshore facilities at the same time. Procedures to quantify the capacity value of geographically dispersed wind resources may not be applicable, such as ones based on the facility’s capacitor factor, may not be sufficiently accurate for the offshore wind development now planned.

Relevant Standards

As discussed in the main body of this document, certain standards have shaped the characteristics of DER relative to BPS security concerns. These standards do not, or should not, apply to transmission IBR. (As discussed previously, distribution-focused standards have historically been inappropriately applied to large transmission-connected PV plants.) There has not been a uniform transmission IBR performance requirement standard. Standards have been developed by various utilities and system operators that are not consistent and may not always reflect best practices. This has led to inefficiencies and misunderstanding by developers of the different requirements.

At the time of the writing of this guidance document, a new IEEE P2800 (Draft Standard for Interconnection and Interoperability of Inverter-Based Resources Interconnecting with Associated Transmission Systems) is in the late stages of development and will become IEEE Std 2800 when complete. This standard intends to provide a uniform, consensus-based detailed set of requirements for all IBR connected to transmission systems. The standard will be supplemented by an IEEE

Recommended Practice (IEEE P2800.2) that will provide preferred test and verification procedures related to the base requirements standard.



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January 27, 2022

Mr. Peter Huynh, Chair
NPCC SS-38 Working Group on Inter-Area Dynamic Analysis

Subject: Increasing levels of DER

Dear Peter,

At its meeting on December 2, 2021, the RSC highlighted concerns with increasing penetrations of DER on distribution feeders that are also a part of an entity's UFLS program design. Specifically, depending on the level of DER, a UFLS distribution feeder may be a net resource and tripping that feeder would not arrest frequency decline and could also accelerate frequency decline.

To enable TFSS to provide the RSC with input on the issue, TFSS requests the addition of an assessment of increasing levels of DER on individual UFLS distribution feeders to the Terms of Reference for the 2023 UFLS Assessment.

Please feel free to call or e-mail me if you have any questions or need more information.

Sincerely,

Joy Brake
Chair
NPCC Task Force on System Studies
(902) 456-4129
Joy.Brake@nspower.ca

cc: Neeraj Lal, Secretary, Task Force on System Studies
Quoc Le, Secretary, SS-38 Working Group on Inter-Area Dynamic Analysis
Gerry Dunbar, Director Reliability Standards and Criteria --- Chairperson RSC



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NPCC 2022 Corporate Reliability Goals

Board Accepted February 2, 2022

NPCC is committed to the vision of a highly reliable and secure North American bulk power system (BPS). NPCC's specific role in support of the overall ERO Enterprise mission is to assure the effective and efficient reduction of risks to the reliability, resilience, and security of the international BPS within Northeastern North America. NPCC works collaboratively with NERC and the other Regional Entities to collectively attain the reliability objectives identified in the *ERO Enterprise Long Term Strategy* which focuses on enhancing risk-based controls to minimize BPS reliability risk, while also identifying, evaluating, and addressing new and emerging issues affecting BPS reliability, including threats to cyber and physical security across North America.

Each of the NPCC 2022 Corporate Goals is presented in terms of support of a Strategic Focus Area within the NPCC 2022 - 2025 Working Draft Strategic Plan and include: Enhancing System Resilience and Assuring Energy Sufficiency; Reliably Integrating the Resources brought forward by Societal De-carbonization Objectives, including Distributed Energy Resources (DER) and Variable Energy Resources (VER); and Addressing Cyber and Physical Threats. The NPCC 2022 Corporate Goals also support the objectives outlined in the NPCC Board and FERC approved *NPCC 2022 Business Plan and Budget*.

There are Threshold and Target performance level aspects identified for each Corporate Goal. Attainment of a previous performance level is a prerequisite for obtaining credit of attainment at a higher performance level. In addition, each aspect of a goal is either Qualitative or Quantitative and each has a committee as a third-party oversight reviewer to support objectivity, transparency, and auditability.



NPCC 2022 CORPORATE RELIABILITY GOALS

<i>Goal</i>	<i>Strategic Focus Areas Objectives</i>	<i>Oversight Reviewer</i>
<i>I - (50%)</i>	Enhancing System Resilience and Assuring Energy Sufficiency <i>NERC Reliability Standards and NPCC Directories are clear, timely, effective in mitigating risks to reliability, and consider cost-effectiveness/impact.</i> <i>The CMEP program promotes a culture of reliability excellence through risk-informed compliance monitoring, mitigation, enforcement, and registration.</i> <i>The NPCC Region has sufficient dispatchable generation and/or operational plans that support reliable operations as renewable resources are added to the energy mix.</i>	<i>Reliability Coordinating and Compliance Committees</i>
<i>II – (25%)</i>	Reliably Integrating the Resources Brought Forward by Decarbonization Objectives, Including Distributed Energy Resources (DER) and Variable Energy Resources (VER) <i>Prevention and mitigation of bulk power system reliability risks due to the increase in DER/VER and the increased connected load that will support meeting societal decarbonization goals.</i>	<i>Reliability Coordinating and Regional Standards Committees</i>
<i>III - (25%)</i>	Addressing Cyber and Physical Security Threats <i>Prevention and mitigation of cyber and physical security risks through active stakeholder engagement and information sharing of current threats and vulnerabilities, security workshops, and development of good industry practice guides.</i>	<i>Reliability Coordinating and Compliance Committees</i>



NPCC 2022 CORPORATE RELIABILITY GOALS

I.	Enhancing System Resilience and Assuring Energy Sufficiency (Weighting: 50% of Total)		
I-A	Enhancing System Resilience	Threshold	Target
IA-1. (5%)	To support excellence in execution and high quality, CMEP Staff aims to maintain compliance with the NERC Rules of Procedure for performing CMEP activities.	No more than 4 instances of noncompliance with CMEP ROP obligations in 2022.	No more than 2 instances of noncompliance with CMEP ROP obligations in 2022.
IA-2. (10%)	To streamline the processing of common noncompliance, NPCC will develop and implement approaches to process the top 8 most violated Standards in NPCC by developing standard specific criteria that will be used by Staff for identifying the extent of the issue and assessing the risk of the noncompliance. (Note: Reliability Standards for this Goal are CIP-007, CIP-010, CIP-004, MOD-025, FAC-008, PRC-005, CIP-002, and CIP-006)	Develop noncompliance processing approach tools for top 8 most violated Standards by 9/22.	Apply developed approach tools to 60 noncompliance by 12/22. Present and share developed noncompliance processing approach tools with the ERO Enterprise for acknowledgement and potential use by 12/22.
IA-3. (5%)	To support resilience for wide-spread long term cold weather events, NPCC will use the NERC CMEP Practice Guide on Cold Weather Preparedness to engage a subset of Generator Owner/Generator Operators.	Develop awareness questionnaire from the NERC Winter Preparedness Practice Guide and send Compliance Bulletin to all 160 registered GO/GOP - by 2/22. Present status to CC – by 3/22.	Perform on-site winterization walk-downs for 3 volunteering GO/GOP - by 10/22. (If COVID travel restrictions are lifted by 5/31/22) Assess questionnaire and provide individual feedback to 2 additional volunteer GO/GOP - by



NPCC 2022 CORPORATE RELIABILITY GOALS

		Present status at Spring 2022 Compliance Webinar. Assess questionnaire and provide individual feedback to 5 volunteer GO/GOP - by 8/22.	10/22. (If COVID travel restrictions do not allow for on-site assessments, the Target for this aspect is 6 additional volunteers, rather than 2.) Present status at Fall 2022 Compliance Webinar. Present status and results to CC – by 12/22.
IA-4. (10%)	Identify and provide recommendation(s) to revise NPCC Reliability Criteria for consideration by the NPCC Members.	Develop a manual load shedding tabletop exercise for NPCC system operators and load shedding entities responsible for determining/designing load shedding programs. Present scope and goals proposal for the tabletop exercise for RCC endorsement - by 6/22 Conduct the tabletop exercise – by 09/21	Report “lessons learned” and any NPCC Reliability Criteria revision recommendations to the RCC for endorsement – by 12/22
I-B	Assuring Energy Sufficiency	Threshold	Target
IB-1. (10%)	Assess gas-electric interdependencies.	Form a technical committee, consisting of members of	Develop a report with addressing the identified



NPCC 2022 CORPORATE RELIABILITY GOALS

		the gas transmission and distribution community as well as the electric utility industry, to identify future NPCC Regional gas-electric interdependency risk(s) by 6/22. Report the results of the NPCC Regional gas-electric review– by 9/22.	future gas-electric interdependencies with recommendations for mitigating actions for RCC endorsement - by 12/22
IB-2. (5%)	Identify and provide recommendation(s) to revise NPCC Reliability Criteria for consideration by the NPCC Members.	Actively participate in the EPRI Resource Adequacy for a Decarbonized Future Project – through 12/22. Draft a report that summarizes resource adequacy scenario definition guidelines in support of regional energy sufficiency and reliability objectives. Status to the RCC – by 9/22.	Present NPCC Regional recommendation(s) addressing identified gaps in commercial reliability adequacy assessment tools and suggest areas new metric, model, and algorithm improvements to the RCC - by 12/22.
IB-3. (5%)	Assure sufficient real-time awareness of DER/VER resource availability and capability and that there are contingency plans when energy limitations affect the resource.	Participate in the US DOE Atlantic Offshore Wind Study - through 12/22. Present identified potential resource energy limitations such as caused by weather	Develop NPCC Regional recommendations for resource adequacy energy sufficiency assessments for RCC endorsement - by 12/22.



NPCC 2022 CORPORATE RELIABILITY GOALS

		events, common mode failure scenarios caused by interdependencies and transmission constraints to the RCC – by 9/22.	

II.	Reliably Integrating the Resources brought forward by Societal De-Carbonization Objectives, including Distributed Energy Resources (DER) and Variable Energy Resources (VER). (Weighting: 25% of Total)	Threshold	Target
II-1. (20%)	Enhance the review and coordination of distributed energy resource requirements and the identification of potential inconsistencies between State and Provincial Regulatory rules and continuing enhancement of a Regionally consistent DER guidelines document by outreach to load serving entities. Reviewing and revising, as required, NPCC Directories to address reliability contributions and challenges of changing technologies.	Conduct three (3) DER/VER Forums to identify State and Provincial Regulatory rules such as associated with electric charging of vehicles and building electrification, to inform enhancements of the DER Guidelines document. Present DER Guideline enhancements to the RCC and RSC for endorsement – by 12/22.	Develop future revisions to NPCC Directory No. 1 to address reliability contributions and challenges of changing technologies and load characteristics for RCC and RSC endorsement – by 12/22.



NPCC, Inc.

NPCC 2022 CORPORATE RELIABILITY GOALS

II-2. (5%)	Enhance outreach to states, provinces, planning authorities and other stakeholders to establish a higher degree of coordination and transparency during the energy transition brought forward by societal de-carbonization objectives.	Conduct three (3) briefings with state and provincial regulators on NERC and NPCC reliability assessments to promote awareness of effective regional transmission planning in the face of the changing resource mix, the impact of emerging technologies, and operability of the BPS with respect to the integration of DER/VER - by 10/22.	Conduct a fourth briefing with state and provincial regulators to identify specific northeast emerging reliability risks (such as associated with NPCC system black start and automatic under frequency load shedding programs for example). Provide quarterly status reports to the RCC and RSC by 12/22.

III.	Address Cyber and Physical Security Threats (Weighting: 25% of Total)	Threshold	Target
III-1. (15%)	Identification of cybersecurity protection and advanced data management requirements associated with next generation substation designs (digital substations) to enhance operational technology (OT) resilience and maximize future grid security.	Enhance interactions with agencies (e.g., NERC E-ISAC, DHS, DOE, Natural Resources Canada, and Federal, State and Local Law Enforcement) through quarterly collaboration sessions to foster a more efficient working model for information and intelligence sharing, to identify cybersecurity threats to Operational Technology.	Conduct an industry workshop to provide an avenue for education and best practices sharing to support the security and resilience of Operational Technology (OT) systems - by 12/22.



NPCC 2022 CORPORATE RELIABILITY GOALS

		Post Quarterly NPCC Security Bulletins.	
III-2. (10%)	Transition NPCC's registered entities from the current compliance portal (CDAA) through Release 3 (audit process) and Release 4 (Inherent Risk Assessments, Compliance Oversight Plans, documentation of assessment of internal controls) of Align and Secure Evidence Locker (SEL) tools in order to better ensure that the enhanced security benefits for the handling of entity data/evidence are realized immediately, efficiently, and uniformly across the ERO Enterprise. (Current NERC project team deadlines are 6/22 and 12/22 for Release 3 and Release 4).	Update the prioritized training strategy used in 2021 with the CC for Release 3 and Release 4 – by 3/22. Conduct prioritized Release 3 training including 2 webinars, notifications, messaging, and posted training material - by 6/22. Present user survey on NPCC Release 3 user training experiences to CC – by 6/22.	Conduct prioritized Release 4 training including 2 webinars, notifications, messages, and posted training material - by 12/22. Present user survey results on overall NPCC Release 4 training and provide a recap of 2022 training efforts to CC for endorsement – by 12/22.

Accepted by NPCC Board of Directors
February 2, 2022

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Project 2017-01 BAL-003 SDT Phase II White Paper

Considerations of Revisions to Address Project
Deliverables

January 6, 2021

RELIABILITY | RESILIENCE | SECURITY



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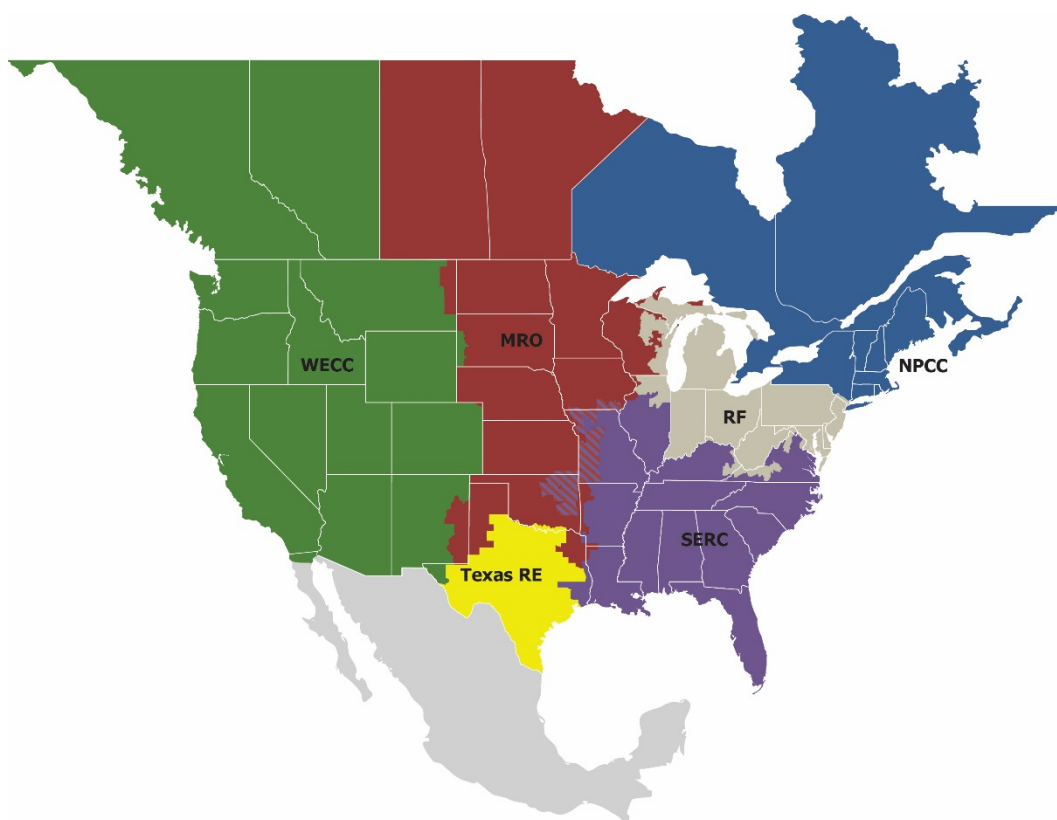
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Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six 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.

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is divided into six 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.



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 Project 2017-01 Standard Authorization Request (SAR), under Phase II, directs the standard drafting team (SDT) to consider assigning responsibilities under BAL-003 to different or additional applicable entities, address Real-time operations of the grid, and address measurement concerns, among other things.

The SDT discussed several different options while trying to address the concerns raised in the SAR. These options include potentially adding additional Balancing Authority (BA) requirements to address Real-time primary Frequency Response reserves, modification to existing BA requirements on performance measurements, and adding Generator Owner (GO) and Generator Operator (GOP) requirements for operational and responsive control. These options are detailed in this White Paper.

The SDT is soliciting industry feedback to narrow in on industry's concerns or support of a modification to BAL-003. To facilitate an understanding with industry as to what the SDT has discussed, this paper lays out multiple options. These options are all viable for modifying BAL-003; however, there are certain items that are either mutually inclusive or mutually exclusive, so the final set of requirements proposed for BAL-003 will depend on comments received from industry so the SDT can assess next steps for Project 2017-01, Phase II.

As an initial step, the SDT determined that the BA performance requirement must remain in place for multi-BA Interconnections. While the measurement methodology might change, a requirement on the BA will not be removed. The BAs (or Reserve Sharing Groups, if applicable) have ultimate responsibility for ensuring all reserve requirements are met at the BA level and that there is not another NERC Registered Entity that is in the position to ensure resources are scheduled to provide the needed service.

While some entities have argued that the generators are the ultimate source of the response, the SDT notes that the GOs and GOPs are not able to ensure that any single generator will be committed and dispatched in such a way to allow the generator to respond to an event. This responsibility is that of the BA alone. Therefore, the ultimate responsibility lies with the BA to ensure sufficient Frequency Responsive Reserves are available, just as it is the BA's responsibility to ensure that sufficient Contingency Reserves and Regulating Reserves are available.

The SDT seeks industry feedback on the following proposed requirements:

- New BA requirement – requires Operational Planning process to address Frequency Responsive Reserves
- New BA requirement – specify minimum governor settings or request governor settings from the GO
 - If the BA specifies a governor requirement, then an additional requirement for a process to allow for exceptions would also be recommended by the SDT.
- New GO requirement – Ensure the governor settings meet the BA specification set above
- New GOP requirement – Ensure the unit is operating with the governor and outer loop controls that are responsive or the BA has been notified that it is not responsive.

The SDT considered a generator performance requirement, and that is discussed in detail within this White Paper. If a Frequency Response performance requirement is determined to be proposed for the generators, the SDT believes it would be appropriate for the BAs to calculate the response for each generator within the Balancing Authority Area (BAA), similar to the process found in the BAL-001-TRE-2, Requirement R2.

Reading through this White Paper should help with understanding the reasoning behind the SDT's current position. The SDT looks forward to feedback from industry participants.

Introduction

Background

The issues related to Reliability Standard BAL-003-1.1 were laid out concisely in the SAR. Those issues were grouped into two phases (see SAR excerpts below). The first phase, Phase I, addressed primarily administrative issues. The second phase, Phase II, addresses more complex issues, which contain both administrative and technical elements.

Excerpts from SAR

Phase I

- *Revise the IFRO calculation in BAL-003-1 due to issues identified in the 2016 Frequency Response Annual Analysis (FRAA) Report, such as the Interconnection Frequency Response Obligation (IFRO) values with respect to Point C and varying Value B;*
- *Reevaluate the interconnections' Resource Contingency Protection Criteria;*
- *Reevaluate the frequency nadir point limitations (currently limited to t0 to t+12);*
- *Review and modify as necessary Attachment A of the Reliability Standard to remove administrative tasks and provide additional clarity, e.g., related to Frequency Response Reserve Sharing Groups (FRSG) and the timeline for Frequency Response and Frequency Bias Setting activities; and*
- *Make enhancements to the BAL-003-1.1 FRS Forms that include, but may not be limited to, the ability to collect and submit FRSG performance data.*

In addition to fixing the inconsistencies outlined above, the SDT may separate the administrative and procedural items and propose they be reassigned to an alternative process subject to Electric Reliability Organization (ERO) and North American Electric Reliability (NERC) Operating Committee (OC) approval.

Phase II

- *Both the IFRO calculations and the allocation of IFROs to reliability entities are retrospective (up to 2 years). The review should determine if there are alternate methodologies which consider characteristics affecting Frequency Response (e.g., load response, mix and type of generation, BAA footprint changes) to make allocation as equitable as possible;*
- *Although BAs and FRSGs are responsible for coordination and/or management of Frequency Response from both resources and loads, response from resources is not addressed. The review should determine if additional reliability entities should have responsibility (e.g., GOPs) for provision of generator governor response; and*
- *Review the measurement methodology of Frequency Response (both System and equipment level):*
 - *The FRM should be reviewed to ensure that over-performance by one entity does not negatively impact the evaluation of performance by another.*

All the items in Phase I were addressed in the balloted and approved Reliability Standard BAL-003-2. Although the needed modifications to accommodate FRSG reporting were included in Phase I, additional improvements to the submittal process to further simplify reporting (possibly eliminating mandatory use of the prescribed Excel spreadsheets) were deferred to Phase II.

To clarify the issues needing to be addressed in Phase II, the SDT held a technical conference via WebEx in March of 2019. Here are the questions posed for discussion during the conference and the findings presented by the SDT.

March 2019 Technical Conference

Questions Posed

- What improvements are needed based on Interconnections' performance under the existing BAL-003-1.1?
- Do reliability needs dictate separate measures for Arresting, Stabilizing (current method), and Recovering periods?
- Do the use and application of adjustments (e.g., non-conforming load, dynamic schedules, etc.) need more clarification? Do we need to add other adjustments?
- What are the pitfalls of delta NAI to measure FRM? Are there viable alternatives?
- How can we best simplify the data collection and submittal process?
- Should measurement also include a prospective Frequency Response Reserve (FRR) requirement?
- What areas of historical performance indicate a need for improvement?
- We have seen an improvement in B space with either no change or slight improvement in C space (FRAA Report)?
- Interconnection nadirs (C point) are constant or increasing?
- Particularly, in light of a changing resource mix, what areas of performance in the future need to be addressed?

Findings presented

Findings presented at the conference in response to the questions posed were:

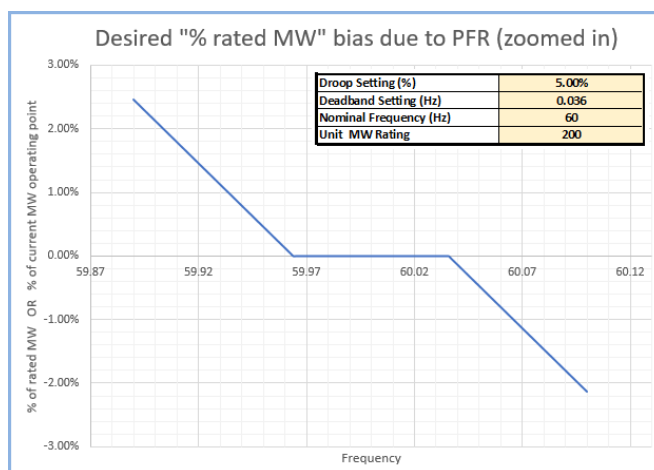
- Although not statistically significant, interconnection performance is stable or slightly improved over the last 4 years (the 2020 FRAA is consistent with the previous 4 years).
- Although the expected future changes in resource mix (driven predominantly by inverter-based resources) will cause changes in the profile over the response period, there is no clear evidence of a reliability need for separate measures (Arresting, Stabilizing, Recovery).
- Clarification of application of adjustments is not needed, but consideration of other adjustments has been made. The administrative burden associated with each (e.g., adjustments for schedule ramping would require coordination of the data submittals of all such schedules between the respective BA partners) precludes the value those identified to date.
- Although the use of NAI (even with existing adjustments) does have limitations and cause inequities for some BAs, no adequate alternative has been identified.
- Data collection and submittal can significantly be simplified. Prototype examples of the submittal forms and corresponding example calculation methods have been developed and are being vetted by the SDT and interested observers.

Other Considerations

This section will provide considerations of other pertinent issues discussed by the SDT during the consideration of the various options for GO/GOP requirements as part of the standard. After describing these other factors, attention will be given to establishing a direction for the SDT with respect to this matter.

Measurement Accuracy

Discussion of the measurement accuracy issues is applicable for interconnection regions where the governor droop and deadband settings are set to 5% droop and +/- 0.036 Hz deadband. Typical non-revenue metering equipment often is known to be 1% accurate. Most sudden imbalance conditions in the Eastern Interconnection do not result in low frequency excursions dropping below 59.9 Hz. The chart below shows the expected % change of facility-rated megawatt (MW) for frequency excursions exceeding the deadband. Notice that the 2% change value occurs at a frequency beyond the majority of the observed frequency excursion limits of the Eastern Interconnection. This results in the situation where the attempted measurement of the frequency responsiveness of many generators in the Eastern Interconnection can be unsuccessful due to the measurement inaccuracies of the equipment in use. Certainly, this can be remedied with projects to use measurement equipment with better accuracy, yet this solution is not without cost and effort. Observed frequency excursions in the Western Interconnection are larger than those in the Eastern Interconnection, so measurement accuracy is a smaller factor in the ability to see the facility response.



Observed frequency excursions

Resource Variability

As mentioned in previous sections, there is **variability in the capability and ability** of existing types of resources to provide primary frequency response due to the modes of operation of those facilities and other important process control constraints. A **generic requirement** which covers existing resource types, therefore, will present GOs with the need for changes in equipment, control modes, efficiencies, and revenue opportunities. In areas where the existing frequency responsiveness is adequate, an application of additional regulations for existing resources may not be warranted. Generic standard requirements for new resource development are more appropriate than detailed, specific requirements. Providing **specific requirements** for certain resource types has the potential to influence, dis-incent, or incent other resource developments in delivering Frequency Response.

Fast Frequency Response

The requirements for fast frequency responsive resources should take into consideration the speed of response characteristics of those resources in comparison to other resources. Certainly, the droop setting controls the

sensitivity of the unit response, and equal sharing of the burden for providing more or less MW for a given frequency excursion will occur given that the excursion lasts long enough for the slowest response timing. If, however, future generating unit resource types with fast Frequency Response become so populous that the MW response needed for arresting and correcting the frequency excursion is available from those fast responding units, the burden would probably not be shared equally with slower responding units even though the droop settings match. At the same time, however, it is understood that those resource types can play an important role during the arresting phase of the frequency excursion.

Frequency Response from New Generation Resources

Provided the trends in the frequency excursion characteristic curve in an interconnection are not markedly showing deterioration coupled with the existing acceptability of the current response, perhaps engaging new generation resources to match the response exhibited by the existing fleet of generators will provide sufficient responsiveness in the future.

The ability to provide sustained Frequency Response from certain types of renewable resources is not guaranteed. Factors include variability in wind speed for wind; operation at maximum power output for wind, solar, steam turbines, and combustion turbines (CTs); intermittent cloud cover for solar; and the current state of charge for battery systems.

The possibility of insufficient Frequency Response stemming from the replacement of traditional synchronous generators (rotating machines) with static-power-conversion-based generation causes focus to be directed towards obligations placed on the new generation to address the issue at the time of the addition of the new resource. The Federal Energy Regulatory Commission (FERC) Order 842 partially addresses this. Interconnection agreements for future resources can specify that all new resources be provisioned with this ability and adequately programmed (controlled) to deliver Frequency Response during normal operation. This ability to have automatic frequency regulation included in the functionality is similar to requiring generating facility equipment to have reactive power production capability, which permits it to deliver automatic voltage regulation (AVR). These provisions, where used and followed, may obviate the need for any additional regulations for GO/GOPs. The adequacy of the existing Frequency Response for the Eastern, Western, and Quebec Interconnections should be considered carefully before new regulation is applied for all generation in each of these interconnections. The frequency excursion characteristics vary from Interconnection to Interconnection.

2017 & 2019 Generator Governor Survey Reports

NERC has performed generator surveys related to frequency response in 2017 and 2019.

These surveys appear to show that generator response to frequency events has increased, although it is still less than expected. It is believed that this increase has been driven due to increased awareness in the industry of the need for frequency response, including efforts by some Balancing Authorities to work with generators to improve response.

TRE Solution

The Texas region has addressed frequency excursion control ability through regional standards specifying governor settings, governor in-service requirements, initial/sustained Frequency Response performance, and credits for load used as a resource (early load shed schemes), and now is developing fast Frequency Response market products.

Market Based Solutions

Many discussions of the growing penetration and density of inverter-based intermittent renewable resources and a forecast of its possible (negative) impact on Frequency Response assumes there is no capability for renewables to provide Frequency Response. This ability may flourish through market requirements and payment for Frequency Response. Market factors would incent the entities to operate these types of resources at less than the maximum available power if properly compensated. Market-driven Frequency Response provision mechanisms can be

developed. These market-based solutions are possibilities instead of provisioning using reliability standard requirements. Both can achieve power injection/withdrawal as needed to regulate the frequency. High-speed power injection and load rejection contracts can arrest frequency declines when dispatched well before the underfrequency load shedding (UFLS) frequency set points in each region. All characteristics of Frequency Response could be incentivized to ensure additional system reliability. BAs may consider acquiring additional Frequency Response through various market means and some resources may elect to participate in market options.

Section 1: Overview of Possible New/Modified Requirements

The rationale for new requirements for both BAs and GOs/GOPs is to have matching requirements for each: one for the operational planning window, one for Real-time status monitoring, and one for performance. The reliability need for each time frame and each functional entity is under much debate.

Existing Requirements

No changes to existing bias setting or measurement reporting requirements.

New/Modified BA Requirements

New BA requirements **may** require a BA to explicitly address planning for Frequency Response reserves in next-day operational planning, develop methods to explicitly monitor Frequency Response reserves in Real-time, and demonstrate Frequency Response reserve maintenance after-the-fact.

Frequency Response Reserves Operational Planning

Explicitly address maintaining Frequency Response reserves in operational plans/procedures.
(See Detail in Chapter 2, R3)

Real-Time Frequency Response Reserves Monitoring

Require BAs to explicitly monitor Frequency Response Reserves in Real-time and to have and meet Real-time targets (static or dynamic). (No formal requirement has been drafted in this paper.)

Real-Time Frequency Response Reserves Performance

Additionally, consideration of an after-the-fact metric on performance (how well did the BA follow its plan?).
(No formal requirement has been drafted in this paper.)

New GO/GOP Requirements

New GO/GOP requirements may require a GO/GOP to explicitly document and communicate Frequency Response capability, develop methods to explicitly monitor and communicate Frequency Response capability in Real-time, and demonstrate Frequency Response performance after-the-fact.

Frequency Responsive Capability

Simple documentation of existence of Frequency Response capability and settings (if capable).

Communication to BA

What information (e.g., just settings or, additionally, actual current capability) should be reported to BA? What mechanism should be used for reporting? And in what periodicity should that information be communicated? All aspects are interrelated (e.g., a one-time settings communication does not need inter-control center communications protocol (ICCP) transfer, but Real-time ramp/headroom capability may).

Is this (could this be) covered by data collection requirements in other standards?

Frequency Responsive Performance

A possible requirement to assess unit performance and meet minimal performance targets.

Administrative Changes

Reporting of data has been reduced to only data needed for multi-BA calculation apportionment and actual required performance metrics. Background data collection, analysis, and calculations are not required to be reported, but prototype calculation methods and tools are developed to provide guidance for users.

Data Collection

A modified spreadsheet form to report needed data for pro rata calculations has been prepared.

Form Replacement

Prototype forms to replace Form 1 and Form 2 have been developed

Section 2: Balancing Authority Requirements Options

Overview

The current Reliability Standard BAL-003-1.1 requires a BA to achieve a median performance on events selected through the frequency event selection process. This process could be thought of as a “past” performance metric since any failure to meet the standard would not be identified until well after the compliance period has passed. This allows the BA to adopt a “wait and see” approach, and puts the interconnection in an assumed state of reliability without any required planning to meet those objectives.

The following requirement was modeled after Reliability Standard VAR-001, Requirement R2, with the intent to move the BA to a forward-looking assessment of available frequency responsive reserves. This is not intended to require the BA to monitor these reserves in Real-time, but simply support a process to evaluate the available Frequency Response in the Operations Planning Horizon, including Real-time operations. While this does not necessarily guarantee performance during an event, it does reduce the risk that a BA might operate in a state with inadequate Frequency Response.

The SDT is proposing a governor (or equivalent control) setting requirement for generating resources connected to the interconnected transmission system. The intent of such a requirement is to:

- Ensure every generating resource is capable of responding to frequency deviations;
- Ensure the BA is aware of the droop and deadband characteristics of the generating resource; and
- Ensure the BA is aware of generating resource operating position and available frequency response.

It has been proposed that a new version, a proposed BAL-003-3, specify the required droop and deadband settings for each generating resource. After careful deliberation, the SDT does not believe it is appropriate to apply a single droop and deadband setting specification to each generating resource. The SDT is proposing that the BA specify the droop and deadband settings and develop an appropriate process for allowing exemptions to the BA’s droop and deadband settings. This process should include exemptions for the governor operating requirement.

The requirement to ensure adequate Frequency Response falls upon the BA. Frequency Response is like other types of Operating Reserve in that a certain amount is necessary to maintain reliability. In the case of Operating Reserve, the BA can choose to carry Operating Reserve on the most effective and efficient resources, while ensuring that there is adequate Operating Reserve in total for the BA. In the same manner, Frequency Response can be procured and dispatched in the most efficient manner across the BA’s entire generating fleet while providing the necessary reliability. Therefore, the SDT elected not to pursue a specific GOP requirement to provide Frequency Response for selected events. Just as there are efficiency and reliability reasons to carry Operating Reserve on specific generating resources, the same logic applies to Frequency Response. Reliability is better served by an analytical approach to provisioning Frequency Response than by requiring each generating resource to provide it at any time for any Frequency Deviation.

Frequency Response is largely determined by the generating resource’s operating point and governor droop and deadband settings. Generating resource types each have unique operating and performance characteristics. For example, when specifying droop, on a hydro generator the control output that changes is gate position. However, a 5% gate change does not equate to a 5% power output change. The same issue applies with Combustion Turbines (CT) and throttle position. The issue becomes more complicated with combined cycle power plants. Generally, the steam turbine does not have a speed governor. Its output varies based on the heat generated (and power) of the CT. In specifying a 5% power droop, if the governor is set to 5%, actual observed power droop is likely to be different. The SDT is proposing that the BA specify droop and deadband settings, which can be based on the BA’s and generating resource’s operating needs and capabilities.

There will be instances where a generating resource is not capable, or it is not desirable to provide Frequency Response. In order to address these cases, the BA shall develop a process that can be applied to determine if a generating resource can be exempted from the requirement to have a governor operating when connected to the interconnected system.

Knowledge of governor status and settings allows the BA to determine the amount of Frequency Response available for any given operating point. With that information, the BA can make the appropriate dispatch decisions to ensure reliability while using the most economic generating resources available. The proposed requirements and the associated justifications describe a coordinated approach to this.

Operational Planning – Process

BA-R3

Each Balancing Authority shall develop and implement an Operating Process, reviewed and maintained at least annually, as part of its Operating Plan to schedule frequency responsive resources sufficient to maintain interconnection frequency equal to or greater than its Frequency Responsive Reserve Obligation.

BA-M3

Each Balancing Authority shall have evidence of scheduling frequency responsive resources based on their assessments of the system. For the operations planning time horizon, Balancing Authorities shall have evidence of assessments used as the basis for how resources were scheduled.

Justification

NERC performed off-peak dynamics analyses of the recommended IFROs for the Eastern, Western, and Texas Interconnections to determine if those levels of primary generator frequency response (PGFR) are adequate to avoid tripping of the first stage of regionally approved UFLS systems in the interconnection. Each of the interconnections prepared light load cases as the starting root case for each of the analyses. In each case, the dynamic governor or load responses of the PGFR of the interconnection closely matched the recommended IFRO value for the prescribed resource loss. All three simulations did not model automatic generation control (AGC), which typically starts to influence PGFR in the 30-45 second timeframe. In all three interconnections analyzed, frequency remained above the highest UFLS set point even with Interconnection PGFR degraded to the IFRO value. The FRAA report presents further analysis of each interconnection for each year.

While the Frequency Response Measure is calculated in MW/.1Hz, the total Frequency Responsive Reserves for each BA should be based on risk associated with anticipated frequency excursions for the applicable interconnection. The responsible entity should have a process to determine the amount of Frequency Responsive Reserves it will plan to have available.

PGFR references and identified risk from the 2012 FRI Report are shown in [Figure 0.1](#) below as an example.

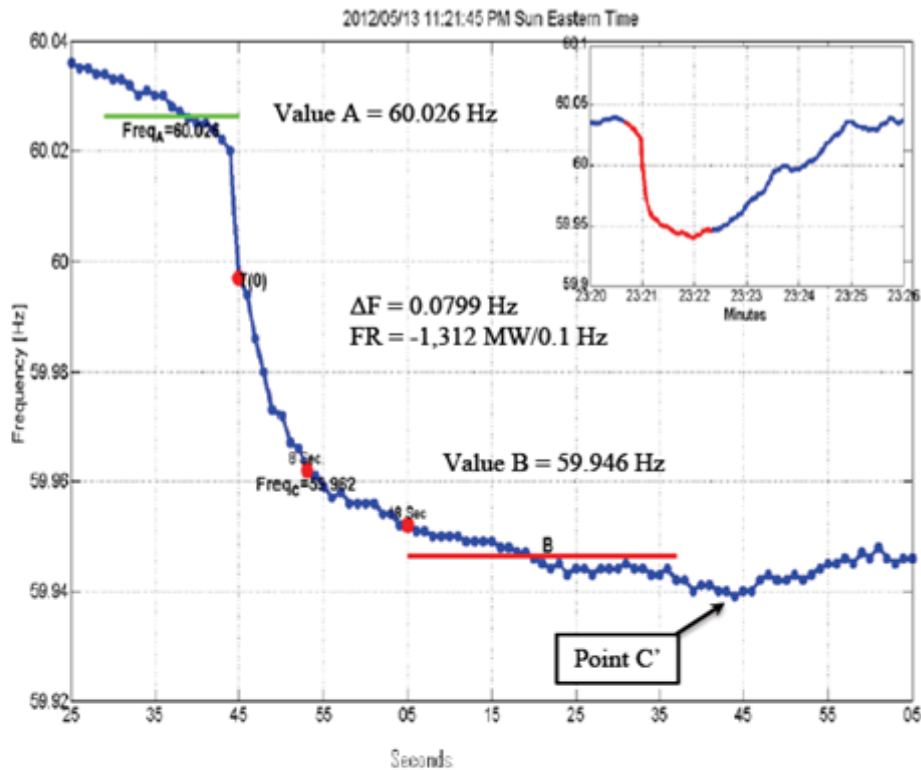


Fig. 24. PGFR Characteristic 11:21 pm Sunday 1,049 MW Resource Loss.

The measurement of Value B (20 to 52 seconds) does not capture the lowest frequency. That frequency point is the true frequency event nadir, hereafter referred to as Point C' ("Point C Prime"), and is normally equal to Point C for events that do not exhibit the so-called "lazy L" effect. It is important that the phenomenon be recorded and trended to determine if it is improving or deteriorating.

NERC Recommendation – Measure and track frequency response sustainability trends by observing frequency between T+45 seconds and T+180 seconds. Calculating a pair of indices comparing that value to both Point C and Value B provides for gauging sustainability. A later alternative comprises the use of arrested PGFR as the PGFR measure.

"NERC should embark immediately on the development of a NERC Frequency Response Resource Guideline to define the performance characteristics expected of those resources for supporting reliability. That guideline should address appropriate parameters for the following:

Figure 0.1: Excerpt from FRI Report October 2012

While these studies assure us that our past performance in each interconnection has been sufficient, they do not necessarily represent the changing resource mix and the potential future performance. This also covers a gap where the BA is required to plan for and carry Contingency Reserves but where those reserves may not be frequency responsive, making them irrelevant to stabilizing the system immediately after a resource loss. In addition to this standard, the Operating Reserve Reliability Guideline should be updated with examples on how to calculate Frequency Response similar to the Electric Reliability Council of Texas (ERCOT) approach with BAL-001-TRE. With the time it takes to modify a standard to address these potential issues in the future, the timing is right to address these known risks now before the interconnections approach a more critical situation.

Operational Planning – Settings

BA-R4

Each Balancing Authority shall specify a minimum droop and deadband setting for the resources located within its boundaries and provide those minimum settings to the Generator Owner.

R4.1

Each Balancing Authority shall provide a copy of the minimum droop and deadband settings to its Reliability Coordinator and adjacent Balancing Authorities within 30 calendar days of a request.

BA-M4

Each Balancing Authority shall have evidence that it specified resource droop, deadband, or equivalent control settings to its resources.

- Each Balancing Authority shall have evidence that the frequency control specifications were provided to its Reliability Coordinator and adjacent Balancing Authorities within 30 calendar days of a request. Evidence may include but is not limited to emails, website postings, and meeting minutes.

Justification

The intent of these proposed requirements is to assist the BA in developing criteria for determining compliance with Requirement R3.

This model is different than the other ancillary services products currently obtained and utilized by BAs to ensure reliability services are available, and it may negatively impact other possible sources of Frequency Response due to lack of compensation. There is also some concern about how generators will be compensated for changes required by its BA, and that the process could be manipulated by a BA by assigning response to certain generators and then limiting dispatch of those generators. But this model simplifies the modeling and operational analysis and allows BAs to require specific settings.

Operational Planning – Exemptions

BA-R5

Each Balancing Authority shall specify the criteria that will exempt generators from:

1. Following the recommended governor droop and deadband settings;
2. Having its governors in service and not blocked; and
3. Having to make associated notifications on governor status changes.

If a Balancing Authority determines that a generator has satisfied the exemption criteria, it shall notify the associated Generator Operator.

BA-M5

Each Balancing Authority shall have evidence of documenting criteria for generator exemptions and documentation of notifications to exempted resources.

Justification

The previous Requirement R4, sets the expectations for resources, and R5 addresses the known limitations that prevent every resource from providing Frequency Response. Requirements R4 and R5 support Requirement R3, which is ultimately needed to comply with Requirement R1. This exemption process should identify resource types that have known mechanical or safety limits to performing Frequency Response. This process also completes the communication loop between the BA and GOP. Other standards are being discussed for the GOP's requirement to perform.

Section 3: Generator Owner/Generator Operator Requirements Options

Overview

Considerable discussion has occurred in recent years of possible requirements for the GO/GOP in the NERC functional model related to improving the ability to control the frequency of an Interconnection during system disturbances. The Frequency Response provided by connected generation and loads during the first minute(s) following a sudden, unplanned upset between the balance of generation and load plays a vital role in arresting the change in system frequency that results from the imbalance.

This section will address four options for engaging the GO/GOP in system frequency management, which is currently required of the BA through the BAL family of NERC Reliability Standards. Since the BA is tasked with frequency control, BA knowledge of the expected Frequency Response that should occur for disturbances can provide confidence in its ability to meet the frequency control obligations. While presenting various methods for this engagement, the following will be discussed:

- the present and forecasted system need for changes in the GO/GOP Frequency Response performance;
- the level of engagement of GO/GOP for delivering Frequency Response – adequacy issues;
- the changing mix of generating facility resource types, their operating/response characteristics, and their impact on Frequency Response in relation to system inertia and reserves;
- information/communication-based requirements versus measured performance requirements; and
- the ability to use market products for soliciting/ensuring adequate provision of Frequency Response.

Changes in the resource mix of electric power generating facilities tend to change the grid dynamics relative to frequency control capability. Lower system inertia results in increased rate-of-change-of-frequency when sudden imbalances in generation and load occur. Each interconnection currently maintains adequate and substantial margin between automatic UFLS set-points and the lowest frequencies experienced in recent years. Many new resource types can be controlled such that they can provide Frequency Response. Many existing synchronous resource types have been modified in the past decade to provide reliable Frequency Response. The present and forecasted system need for Frequency Response and the response capability of resources are closely related issues.

Options that the SDT has discussed include:

1. Copy all BAL-001-TRE performance requirements, including the requirement for the BA to calculate the response for all generators within their BA footprint. (**Option 1** below.)
2. Create GO/GOP performance requirements with the GO/GOP responsible for the calculation of the performance. (**Option 2** below.)
3. Limit the GO/GOP requirements to just “Operate with the Governor in Service” and “Notify if out of service” only. (**Option 3** below.)
4. Create requirements for the GO/GOP to provide the droop, deadband and other requested data to the BA. (**Option 4** below.)
5. A combination of 3 and 4 above

Each possible method of addressing the GO/GOP in frequency control through the regulatory process that has been discussed by the BAL-003 SDT under Project 2017-03 will be examined and evaluated in this document.

Resource Frequency Response Performance Requirement

The Project 2017-01 SDT has discussed whether it would be appropriate for GO/GOP requirements to replace the current BA requirement due to comments received during the SAR process. During discussions, the SDT determined:

1. The largest BAs in the Eastern and the Western Interconnections are responsible for determining the commitment and dispatch levels of unassociated generation within their footprint during Real-time operations. Therefore, without a BA requirement to ensure the generation fleet is committed and dispatched in a manner to allow response, the GO/GOP would be at risk of meeting a requirement that would replace the current BA requirement while the generation could be committed and/or dispatched such that all available generation meets the performance requirement but the interconnection fails to have sufficient response.
2. Allocating the IFRO to GO/GOPs would either require a Real-time allocation process to address units on and off-line or be likely to aggravate minimum load/generation balancing issues already seen at times as GO/GOPs would need to keep some generation online to provide the required response.

For these reasons, the SDT determined that a GO/GOP requirement could not replace the existing BA requirement. Instead, any GO/GOP requirement would have to be in addition to the existing BA requirement. Therefore, the SDT has focused its discussions in this direction.

This possible set of requirements would be like some or all of those that exist today in the Texas Reliability Entity (TRE) regional standard, BAL-001-TRE-2. Individual resources, whether a single generating unit or an aggregated group of resources such as a wind farm, would be measured against an expected level of response during identified frequency events to determine if the resources are responding.

For ease of understanding and reference, a summary of the pertinent TRE requirements is provided:

- R2 – BA calculates the Frequency Response (both initial and sustained) for each generator;
- R6 - GO must set controls to meet three criteria: droop, deadband and slope;
- R7 – GO shall operate the generator with the governor in-service unless there is a valid reason for it to be out-of-service and the GOP has been notified.
- R8 – GOP will notify the BA within 30 minutes of change in status of the governor.
- R9 – GO will meet 12 month rolling average initial Frequency Response performance of 0.75 based on participation in at least 8 events.
- R10 – GO will meet 12 month rolling average sustained Frequency Response performance of 0.75 based on participation in at least 8 events.

The SDT notes that the TRE standard does not have a BA performance requirement. However, ERCOT, as the registered BA, does have a performance requirement under the NERC BAL-003 standard.

Discussion of the Different Options

Option 1 – Performance Requirement BA Calculation

Under Option 1 above, the SDT discussed the benefits, possible hurdles and perceived negatives associated with the potential requirements structure. These are listed below:

Benefits

- The requirements are relatively clear and understood.
- Data available from TRE shows the process provides an adequate level of reliability.
- Expectation that the amount of Frequency Response seen would remain steady or increase regardless of changes in the generation mix.

Possible Hurdles

- Data transfer rates between generators and BAs in many areas may not be sufficient to allow the BA to make the calculation. (ERCOT uses a 1-second data transfer rate compared to 2-to-6 seconds in other BAs).
- Calculation process may be onerous for smaller BAs.
- Generators may incur expenses to address performance requirements with no clear process for compensation.
- Interconnection size may impede the ability to identify a significant number of events that exceed the deadband.

Negatives

- For BAs with large geographic areas, Frequency Deviations across the system may cause complications for the calculation process.
- Potential for penalizing GO/GOP when more than adequate response across the BA and interconnection is provided (even if the BA and GO/GOP are the same entity).
- Compliance burden may be greater than the potential reliability benefit by placing a compliance obligation on all GO/GOP when over multiple years actual response comes from 50 percent or fewer of units.
- Mandatory performance without clear compensation may negatively impact development of alternative providers of Frequency Response.

Option 2 – Performance Requirement GO Calculation

Under Option 2, the identified list of benefits, possible hurdles and negatives are much the same. The main differences would be related to the data transfer rate and geographic issues and depends on whether the BA, or the GO, would be responsible for calculations. Regardless, the larger number of entities involved in the calculation process would likely increase the administrative burden of the process.

Benefits

- Clear and relatively easy to understand.
- Data available showing experience in TRE to support adequacy of the process.

- Increased Frequency Response.
- May provide reliability value if proven to be needed.

Possible Hurdles

- Calculation process may be onerous for smaller GO/GOPs.
- Generators may incur expenses to address performance requirements with no clear process for compensation.
- Data needed to make the calculation at the GO/GOP level may require significant modifications to data collection at the plant level.
- Interconnection size may impede the ability to identify a significant enough number of events that exceed the deadband.

Negatives

- Large number of entities required to have the data necessary for the calculation, and maintaining trained individuals to perform the calculation may cause the process to be administratively burdensome.
- Potential for penalizing GO/GOP when more than adequate response across the BA and interconnection is provided (even if the BA and GO/GOP are the same entity).
- Compliance burden may be greater than the potential reliability benefit by placing a compliance obligation on all GO/GOPs when, over multiple years, the actual response comes from 50 percent or fewer of units.
- Mandatory performance without clear compensation may negatively impact development of alternative providers of Frequency Response.

BAL-001-TRE-1 became effective on April 1, 2014. Under the standard, a generator must participate in a minimum of 8 frequency events to have a measurable performance obligation. As of August 1, 2020, approximately 20 percent of the generators in the TRE footprint have been scored on 8 or more events. Of the remaining generators, 24.3 percent have received a score in less than 8 events and 55.7 percent have not received a score in any event; therefore, at this time they do not have an official compliance obligation for performance. All generators have an obligation under the standard to have the required settings in place, regardless of event participation.

Option 3 – Resource Governor In-service Requirement

This possible requirement for the GO/GOP for frequency control can be compared with Reliability Standard VAR-002, which is concerned with voltage control. Reliability Standard VAR-002, in paraphrase, obligates the GO or GOP to:

- operate each generator with the automatic voltage regulator in-service and controlling voltage;
- maintain the voltage or reactive schedule provided by the TOP;
- modify voltage when instructed or provide an explanation for not being able to do so;
- notify the TOP of AVR, PSS, or voltage controlling device status changes;
- notify the TOP of reactive capability status changes;
- provide GSU and Aux transformer tap settings, ranges, and transformer impedance data to the TOP and TP;
- modify GSU transformer tap settings, if possible, at the request of the TOP; and

- follow alternate directions by the TOP, or be exempted due to being in startup, shutdown, or testing mode.

Whereas the requirements of Reliability Standard VAR-002 apply to the AVR equipment located at generating facilities for the purpose of voltage control, possible requirements of a proposed BAL-003-3 could apply to the turbine/plant control systems to promote system frequency control and stability. These requirements could take the form of the following:

- operate each governor/speed/frequency/MW set point controller with the primary frequency regulator in-service and controlling frequency;
- maintain the scheduled frequency using a proportional control with percent droop and frequency deadband; settings (see the next section for a discussion of specifying and/or reporting the settings between the GO/GOP and the BA);
- provide an explanation to the BA for not being able to contribute to frequency control;
- notify the BA of frequency controlling device status changes;
- provide the in-service frequency controlling device settings to the BA;
- modify the in-service frequency controlling device settings, if possible, at the request of the BA; and
- follow alternate directions by the BA, or be exempted due to being in startup, shutdown, or testing modes.

FERC Order 842 requires minimum interconnection requirements for new units/facilities, including the installation, maintenance, and operation of a functioning governor. The first bullet above is akin to that part of FERC Order 842. There is significant debate about whether, given the current state of acceptable frequency responsiveness, new resource requirements to provide Frequency Response will provide adequate ability to arrest and correct future frequency disturbances.

In the above-bulleted list of possible GO/GOP requirements, several are informational in nature, where the GO/GOP is providing information to the BA on the ability to control frequency (providing an explanation of not being able to control frequency, notifying due to status changes, etc.). Where the BA wants this information to use for a reliability purpose, the BA may require it through the data specifications developed under Reliability Standard TOP-003. Considering a GO/GOP requirement to provide information that has not previously been required (by Reliability Standard TOP-003) raises the question of whether the information will be used for any purpose.

This requirement is one which can be "coupled" with new BA requirements for having a Frequency Response reserve plan, knowing the Frequency Response reserves available. Although traditional generation does not have on/off switches for governors, differing vastly from AVR control modes, improper settings can defeat an otherwise responsive governor. A turbine control system may not have system frequency (speed) built into the governor during on-line operation. Examples of this are steam valve position and hydro wicket gate position regulators. Solar and wind generating facilities often operate at the maximum power operating point and, therefore, are unable to provide any additional response for underfrequency disturbances. Additionally, the variability of the power source for these types of facilities prevents certainty of the 100% availability for Frequency Response. Certain steam turbine driven generators operate with the turbine steam valves in a wide-open position which will prevent additional generation from being available for underfrequency events. Some CT controllers run fuel control at a maximum exhaust temperature mode which may prevent additional generation from being available for underfrequency events.

Modes of Operation

The following is a discussion of the ability to implement possible requirements ("Options") outlined above and provides considerations relevant to each. Operating each governor or equivalent controller with the primary

frequency regulator in-service and controlling frequency, in most cases, should not be a difficult proposition due to the following characteristics of most control systems:

- A frequency-dependent bias component exists in the control equipment functionality; and
- In-service/out-of-service control switches or variable parameter settings permit the tuning and detuning of the responsiveness of the frequency-dependent bias component.

There could, however, be other important process elements or operating modes which may serve to eliminate, either partially or wholly, the ability of this frequency-dependent bias component from providing the desired Frequency Response during frequency disturbances. These include, but are not limited to:

- The importance of and focus given to reactor controls at nuclear generating stations.
 - Some controls on these units have shown the ability to provide Frequency Response, while others intentionally have detuned the controls by various methods to prevent their operation, thereby increasing the stability of the reactor control.
- Current, widely-used modes of operation for wind, solar, CTs, and steam turbines may permit or may restrict responsiveness. These modes include:
 - operation at the maximum power point (solar, wind, batteries, steam turbines, CTs, etc.);
 - operating at the minimum power point in the control continuum;
 - CT running at the maximum allowable exhaust temperature limit; and
 - coal-fired unit on the verge of coal requirement switching point to change load levels.

Prescribed changes to the modes of operation would be necessary in these instances to permit the existing equipment to provide Frequency Response. Maintaining the scheduled frequency using frequency-dependent bias components with specified limits to the sensitivity settings has been shown to be possible where generating units are not constrained by other operational limitations. A discussion of the sensitivity settings (droop, deadband) is part of the next section of this document.

Resource Frequency Response Communication Requirement

Option 4 – Notifications and Governor Settings

Notifications by the GO/GOP to the BA could be provided to indicate the ability of a unit, or change in the ability of a unit, to provide Frequency Response. For each unit, operational experience and certain test results can provide this intelligence which can be conveyed to the BA for use in frequency response reserve planning. Many generating units will have known operating conditions where Frequency Response can be expected. Additionally, operating conditions resulting in no Frequency Response are often known. Real-time determination and communication of these instances would prove to be more challenging in some cases, as there may be difficulty or uncertainty in incorporating all aspects of unit operating conditions into the logic used to indicate the expected responsiveness. Where on/off switches are used in control systems for the frequency responsive component of the control, changes to the set points of the control can easily be communicated to the BA.

Providing the in-service frequency controlling device settings to the BA is expected to be a one-time event as these settings are not often modified. Modifying these settings is possible and are recommended to be changed while the controller is not in service. Requiring a unit to be offline for these changes impacts the speed in which changes can be implemented. Consideration should be given to the variation in droop and deadband settings of governor primary frequency control settings for all generating units in each interconnection. A coordinated approach for contributions from each facility during Frequency Disturbances is desired. A secondary effect of any changes to the droop and

deadband settings could cause the model verification performed as part of Reliability Standard MOD-027 to become invalid, and this would trigger a requirement to re-verify that model.

Exceptions to any prescribed Frequency Response requirement for the GO/GOP need to be considered and permitted for certain situations. These include unique unit attributes allowed for alternate directions by the BA, being in startup, shutdown, or testing modes, or other individual peculiarities or anomalies that exist with a generating facility. These types of exceptions are analogous to voltage schedule adherence exceptions which are allowed under Reliability Standard VAR-002. Communication and discussion of these exceptions should be expected between the GO/GOP and the BA.

Consideration of Real-time Information

Generating units providing Real-time information to BAs on the available Frequency Response capability would provide valuable transparency to the expected Frequency Response. The SDT has discussed a BA requirement (see Section 1: New/Modified BA Requirement) to calculate and have available a set amount of Frequency Response reserves in Real-time. A requirement for the generating units to provide information to the BA on the capability would be a direct complement to this requirement. No BA requirement for Real-time Frequency Response reserves determination was drafted.

Communication of Governor Settings

Areas the SDT has been discussing around the topic of Real-time status, availability, and expected droop and deadband settings are:

- Requirement to provide the data;
- Settings to be provided, or prescribed; and
- What parameters should to be communicated.

Requirement to provide the data – Options 4(a) and 4(b)

The requirements for providing Frequency Response data to the BA should be considered for all generating resources including but not limited to generators, non-synchronous machines, and storage.

Options discussed by the SDT for a requirement to provide Real-time Frequency Response data were:

Option 4(a): Add a new BA requirement in Reliability Standard BAL-003.

Option 4(b): Provide recommendation for information to be provided under Reliability Standard TOP- 003.

Settings to be provided, or prescribed

Options discussed by the SDT on the droop and deadband settings information to be provided were:

1. The droop and deadband settings can be specified to the generator by the BA.
2. The GO would communicate the current droop and deadband settings of the unit to the BA.

Discussion of options: 4(a) and 4(b)

Under Option 4(a), a new requirement would be added to Reliability Standard BAL-003 for the BA to provide the specified Frequency Response communications to the GO. The BA would be able to set the required droop and deadband for all resources (see Section 2, BA R4). BAs would need to determine if they required the “default” deadband (no greater than 36 MHz), and droop (no greater than 5%), or if there were different settings that would be appropriate. It will also need to be determined if a resource type would drive the Frequency Response setting and

an exception process would need to be considered for resources unable to provide Frequency Response (See Chapter 2, BA R5).

Benefits

- Ensures the BA knows what to expect from all generators in its footprint;
- Allows BAs to set requirements aligned with ensuring adequate Frequency Response capability is available on the system; and
- Would minimize the information that would need to be provided in Real-time from the GO to the BA.

Possible Hurdles

- Requires BAs to put processes in-place to define the required droop and deadband settings;
- Could require measurable staff support to respond to generator inquiries and potential discrepancies between generator capabilities and requirements.

Negatives

- Potential concerns over large discrepancies between BAs on requirements for droop and deadband settings; and
- Potential concerns over fairness between all generators in a given BA, and potentially different settings or exemptions between resource types.

Under Option 4(b), the GO would communicate to the BA the current droop and deadband settings of the unit. There would not be a set droop or deadband expectation for the resources. Rather, this would ensure the transparency of the resource capability and operations. The Frequency Response communications from the GO/GOP to the BA would be managed under the existing (or modified) TOP-003 Reliability Standard. A benefit to this method is that existing processes and data exchange can be used to provide the additional data. A hurdle to this method may be that a new SAR for modification to the existing TOP-003 Reliability Standard may be needed to allow for this data to fit within the requirements. Adding data requirements without a clear understanding of how this data will be used by the BA does not fulfill the contemplated requirements for the BA documented in Sections 1 and 2.

Benefits

- Would allow the BA to have situational awareness of available Frequency Response reserves; and
- Minimal cost to implement communication of the droop and deadband settings.

Possible Hurdles

- This information is already being communicated to the Transmission Planner as part of the Reliability Standard MOD-027 data; and
- Determination needs to be made as to whether this data would be usable by the BA, or if this data would not be valid for Real-time awareness and reserve calculations.

Negatives

- Potential to have significant data exchange requirements between the generator and BA; and
- While increasing visibility, this requirement would not necessarily increase Frequency Response.

Section 4: Summary of Options for Requirements

Balancing Authority Requirements

R3 – Operational Planning process to schedule adequate Frequency Response reserves

- A. **BA-R3:** Each Balancing Authority shall develop and implement an Operating Process, reviewed and maintained at least annually, as part of its Operating Plan to schedule frequency responsive resources sufficient to maintain interconnection frequency equal to or greater than its frequency responsive reserve obligation.

R4 - Governor Settings

- A. **BA-R4:** BA specifies minimum Governor Settings in its appropriate data specification (droop, deadband, and operating mode) for Generators within BA Footprint.
- B. **BA-R4.1** Each Balancing Authority shall provide a copy of the minimum droop and deadband settings to its Reliability Coordinator and adjacent Balancing Authorities within 30 calendar days of a request.

To be able to plan and schedule sufficient Frequency Response reserves, BAs will need actual governor settings from each generator in their footprint. Where should any potential request for data (droop, deadband, and operating mode) from the GO/GOP to the BA be addressed?

R5 - Governor Setting/Operation Exemption

- A. **BA R5:** The Balancing Authority specifies exemption process for governor settings (droop, deadband, and operating mode) in BA R4.

Generator Owner/Operator Requirements

Option 1 – Performance Requirement BA Calculation

Requirements similar to BAL-001-TRE where the local BA performs the generator performance calculations.

Option 2 – Performance Requirement GO Calculation

Requirements similar to BAL-001-TRE where the GO/GOP performs the generator performance calculations.

Option 3 – Resource Governor In-service Requirement

Requirements similar to VAR-002 for voltage control equipment applied to the turbine/plant speed / MW/frequency control systems. These requirements may take the form of the following:

- operate each governor/speed/frequency/MW set point controller with the primary frequency regulator in-service and controlling frequency;
- maintain the scheduled frequency using a proportional control with percent droop and frequency deadband; settings (see the next section for a discussion of specifying and/or reporting the settings between the GO/GOP and the BA);

- provide an explanation to the BA for not being able to contribute to frequency control;
- notify the BA of frequency controlling device status changes;
- provide the in-service frequency controlling device settings to the BA;
- modify the in-service frequency controlling device settings, if possible, at the request of the BA; and
- follow alternate directions by the BA, or be exempted due to being in startup, shutdown, or testing modes.

Option 4 – Notifications and Governor Settings

This possible requirement would require

- notifications by the GO/GOP to the BA could be provided to indicate the ability of a unit, or change in the ability of a unit, to provide Frequency Response
- Providing the in-service frequency controlling device settings to the BA. Two methods of this communication are being considered:
 - a. The droop and deadband settings can be specified to the generator by the BA.
 - b. The GO would communicate the current droop and deadband settings of the unit to the BA.

Conclusion and Recommendations

Conclusion

Various methodologies are available for the establishment of systems to arrest, stabilize, and restore to normal any sudden imbalances in generation and load which manifest themselves in Frequency Disturbances. This White Paper has investigated several methods as possible approaches that are detailed in Chapters 2 and 3. Additionally, other relevant considerations including varying existing resource capabilities, new technology capabilities, existing Frequency Response adequacy measures, projected Frequency Response adequacy estimations, and market solutions have been presented.

Recommendations

The SDT recommends a four-layered approach to provide for the adequacy of Frequency Response resources:

1. Require BAs to gather information on a GO's ability to provide Frequency Response, where needed, to permit improved Frequency Response reserves planning.
2. Limit the GO/GOP national standard requirement for frequency control to one that is similar to the existing GO/GOP requirement for the provision of voltage control for resources with the ability to perform the function.
3. Allow the provisions contained with the FERC Order 842, coupled with Interconnection Agreements for future connected resources, to procure and establish additional frequency responsiveness. New resources with this capability included in the functionality allow for marketplace solutions.
4. Permit the establishment of market incentives for areas/regions where additional reserve is desired.

Standard Authorization Request (SAR)

Complete and submit this form, with attachment(s) to the [NERC Help Desk](#). Upon entering the Captcha, please type in your contact information, and attach the SAR to your ticket. Once submitted, you will receive a confirmation number which you can use to track your request.

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:	<u>Modifications to</u> PRC-005-6 ~~applicability to AVR protective functions~~		
Date Submitted:	<u>6/8/2020/27/21</u>		
SAR Requester			
Name:	Brian Kasmarzik, Chair		
Organization:	Project 2019-04 Modifications to PRC-005-6 SAR Drafting Team		
Telephone:	314-554-4315	Email:	BKasmarzik@ameren.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?):			
PRC-005 will be revised to provide clarity that the BES protective functions enabled within excitation systems (including analog/digital Automatic Voltage Regulators (AVRs)), and BES protective functions enabled within ~~other~~ control systems, that respond to <u>measured BES</u> electrical quantities and trip BES elements either directly or via lockout or auxiliary tripping relays are within the scope of the ~~standard project~~. <u>Control systems that do not contain BES protective functions that respond to measured BES electrical quantities are not within the scope of this project. The clarifying changes would apply to the Facilities as defined in PRC-005-6.</u> The clarity that is needed is regarding protective functions inside excitation systems and control systems which are not stand-alone relays, but otherwise perform as a BES Protection System. Without clear applicability, the industry is struggling with how to implement PRC-005 and what testing is acceptable to meet the required maintenance activities prescribed by PRC-005. The lack of clarity presents a reliability gap in the application of PRC-005. Additionally, there are Protection System station direct current (DC) supply technologies that do not currently have maintenance activities established in PRC-005. The standard needs to address battery-			

Requested information

based station DC technologies that are not covered by PRC-005 and consider other alternative technologies, both battery-based and non-battery-based.

This project would modify Reliability Standard PRC-005 to be consistent with the Federal Energy Regulatory Commission (FERC)-approved changes to registration as part of the Risk Based Registration (RBR) initiative by specifying Underfrequency Load Shedding (UFLS)-only Distribution Providers (DPs) in the Applicability Section.

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

Provide clear, unambiguous applicability of PRC-005 to protective functions and provide the specificity needed for the industry to consistently identify and implement the required maintenance activities.

Provide for the use of alternative Protection System station DC supply technologies, battery-based and non-battery-based, and ensure that they are subject to maintenance requirements.

This project would modify Reliability Standard PRC-005 to be consistent with the FERC-approved changes to registration as part of the RBR initiative and to add UFLS-only DPs in the Applicability Section.

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

Modify PRC-005 to provide clarity that the BES protective functions enabled within analog/digital AVR, excitation systems, and BES protective functions enabled within ~~other~~ control systems that respond to measured BES electrical quantities and trip BES elements either directly or via lockout or auxiliary tripping relays are within the scope of the standard. Only those control systems that contain BES protective functions that respond to measured BES electrical quantities are within the scope of this project. Modifications to PRC-005 could also include defining terms, revising applicability, modifying maintenance activities and intervals, or other appropriate modifications needed to provide clarity. In addition, modify the PRC-005 Supplementary Reference and FAQ to align with revisions to PRC-005.

~~The clarifying changes would apply to BES Protection Systems and BES protective functions applied on generators, dispersed power-producing resources from the point of aggregation (greater than 75 MVA) to the point of interconnection, static and synchronous condensers and other BES elements as defined. The clarifying changes would apply to the Facilities as defined in PRC-005-6. The individual generators identified through inclusion I4 of the BES definition are to remain outside the scope of the SAR project.~~

Modify PRC-005 to establish maintenance requirements for Protection System DC supply technologies that are not currently covered.

This project would modify Reliability Standard PRC-005 to be consistent with the FERC-approved changes to registration as part of the RBR initiative and to add UFLS-only DPs in the Applicability Section.

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 justification¹ 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 North American Generator Forum (NAGF) received feedback from members indicating that there was confusion regarding the applicability of protective functions inside synchronous generator excitation systems to PRC-005. The primary cause of confusion is the use of the NERC term "Protection System," which specifies "relays" but not the protective functions that are typically (but not always) associated with relays. Excitation systems may measure and utilize similar quantities as protective relays and may perform similar functions as protective relays applicable to PRC-005. For this reason, the SAR drafting team agrees that the aforementioned protective functions within excitation systems and ~~other~~ control systems need to be clearly and explicitly applicable to PRC-005.

PRC-005 will be modified to provide clarity on the inclusion of BES protective functions enabled within excitation systems (analog/digital AVR), and BES protective functions enabled within ~~other~~ control systems, that respond to measured BES electrical quantities and ~~or~~ trip BES elements either directly or via lockout or auxiliary tripping relays. ~~The clarifying changes would apply to BES Protection Systems and BES protective functions applied on generators, dispersed power producing resources from the point of aggregation (greater than 75 MVA) to the point of interconnection, static and synchronous condensers and other BES elements as defined. The clarifying changes would apply to the Facilities as defined in PRC-005-6. The individual generators identified through inclusion I4 of the BES definition are to remain outside the scope of the project.~~

The SAR drafting team recommends considering the specification of American National Standards Institute (ANSI) Standard Device Numbers for the applicability to PRC-005 as outlined in the Applicability Section 4.2. Other options to provide clarity include: developing standard-specific definitions, developing or revising existing terms in the NERC Glossary of Terms, or making other modifications to the Applicability section.

The maintenance tables should be updated to include the aforementioned BES protective functions enabled within ~~other~~ control systems, and the associated maintenance activities and intervals.

Additionally, the maintenance tables should be updated to include new DC supply technologies for Protection System(s) not currently captured.

Entities registered as ULFS-Only (DPs) have PRC-005 applicable Protection Systems, but are not expressly listed as Applicable Entities in Section 4.1 UFLS-Only DPs should be added to the Applicability Section to avoid any confusion and to be consistent with the FERC-approved RBR registration changes.

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	
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):	
The SAR ~~DT~~ -drafting team is seeking industry input regarding cost impact.	
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (e.g., Dispersed Generation Resources):	
~~The clarifying changes would apply to the facilities as defined in PRC-005-6. The clarifying changes would apply to BES Protection Systems and BES protective functions applied on generators, dispersed power producing resources from the point of aggregation (greater than 75 MVA) to the point of interconnection, static and synchronous condensers and other BES elements as defined. The items under consideration related to DC supply technologies would impact multiple facility owners.~~	
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):	
Generator Owner (GO), Transmission Owner (TO), Distribution Provider (DP), Underfrequency Load Shedding (UFLS)-only DP	
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 NAGF and the NEI worked together to generate the initial SAR and communicated the issue in advance to NERC.	
~~The SAR drafting team held team meetings, vetted comments received by industry, and edited the original SAR based on industry comments. The SAR drafting team posted the draft SARs for formal comment periods. The SAR drafting team conducted an industry webinar during SAR development and conducted additional outreach activities with EEI and NAGF.~~	
This project would modify Reliability Standard PRC-005 to be consistent with the FERC-approved changes to registration as part of the RBR initiative and to add UFLS-only DPs in the Applicability Section.	
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)?	
Options to provide clarity for PRC-005 include: developing standard-specific definitions, developing or revising existing terms in the NERC Glossary of Terms, or making other modifications to the Applicability section. In the event of developing or revising existing terms in the NERC Glossary of Terms, review of the effects on other standards must be performed.	
Are there alternatives (e.g., guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.	

² Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

Reliability Principles

Does this proposed standard development project support at least one of the following Reliability Principles ([Reliability Interface Principles](#))? Please check all those that apply.

☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☐	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☒	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☒	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Market Interface Principles

Does the proposed standard development project comply with all of the following [Market Interface Principles](#)?

Enter
(yes/no)

1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Identified Existing or Potential Regional or Interconnection Variances

Region(s)/ Interconnection	Explanation
e.g., NPCC	None

For Use by NERC Only

SAR Status Tracking (Check off as appropriate).

☒ ☐ Draft SAR reviewed by NERC Staff	☐ Final SAR endorsed by the SC
☒ Draft SAR presented to SC for acceptance	☐ SAR assigned a Standards Project by NERC
☒ ☐ DRAFT SAR approved for posting by the SC	☐ 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
3	February 22, 2019	Standards Information Staff	Added instructions to submit via Help Desk
4	February 25, 2020	Standards Information Staff	Updated template footer

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 initial 45-day formal comment period with ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	03/18/20
SAR posted for comment	04/08/20

Anticipated Actions	Date
45-day formal comment period with ballot	August 2021
45-day formal comment period with ballot	January 2022
10-day final ballot	March 2022
Board adoption	August 2022

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None

A. Introduction

1. **Title:** Cyber Security — Security Management Controls
2. **Number:** CIP-003-~~X8~~
3. **Purpose:** To specify consistent and sustainable security management controls that establish responsibility and accountability to protect BES Cyber Systems against compromise that could lead to misoperation or instability in the Bulk Electric System (BES).
4. **Applicability:**
 - 4.1. **Functional Entities:** For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as “Responsible Entities.” For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.
 - 4.1.1. **Balancing Authority**
 - 4.1.2. **Distribution Provider** that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:
 - 4.1.2.1. Each underfrequency Load shedding (UFLS) or undervoltage Load shedding (UVLS) system that:
 - 4.1.2.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
 - 4.1.2.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.
 - 4.1.2.2. Each 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. Reliability Coordinator****4.1.6. Transmission Operator****4.1.7. Transmission Owner**

4.2. Facilities: For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 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 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.
~~All BES Facilities.~~

4.2.3. Exemptions: The following are exempt from Standard CIP-003-~~X8~~:

4.2.3.1. Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

- 4.2.3.2. Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters (ESPs).
- 4.2.3.3. The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.
- 4.2.3.4. For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

5. Effective Dates: See Implementation Plan for CIP-003-X.

~~See Implementation Plan for CIP-003-X8.~~

~~6. Background:~~

~~Standard CIP-003 exists as part of a suite of CIP Standards related to cyber security, which require the initial identification and categorization of BES Cyber Systems and require organizational, operational, and procedural controls to mitigate risk to BES Cyber Systems.~~

~~The term policy refers to one or a collection of written documents that are used to communicate the Responsible Entities' management goals, objectives and expectations for how the Responsible Entity will protect its BES Cyber Systems. The use of policies also establishes an overall governance foundation for creating a culture of security and compliance with laws, regulations, and standards.~~

~~The term documented processes refers to a set of required instructions specific to the Responsible Entity and to achieve a specific outcome. This term does not imply any naming or approval structure beyond what is stated in the requirements. An entity should include as much as it believes necessary in its documented processes, but it must address the applicable requirements.~~

~~The terms program and plan are sometimes used in place of documented processes where it makes sense and is commonly understood. For example, documented processes describing a response are typically referred to as plans (i.e., incident response plans and recovery plans). Likewise, a security plan can describe an approach involving multiple procedures to address a broad subject matter.~~

~~Similarly, the term program may refer to the organization's overall implementation of its policies, plans, and procedures involving a subject matter. Examples in the standards include the personnel risk assessment program and the personnel training program. The full implementation of the CIP Cyber Security Reliability Standards could also be referred to as a program. However, the terms program and plan do not imply any additional requirements beyond what is stated in the standards.~~

~~Responsible Entities can implement common controls that meet requirements for multiple high, medium, and low impact BES Cyber Systems. For example, a single cyber security awareness program could meet the requirements across multiple BES Cyber Systems.~~

~~Measures provide examples of evidence to show documentation and implementation of the requirement. These measures serve to provide guidance to entities in acceptable records of compliance and should not be viewed as an all-inclusive list.~~

~~Throughout the standards, unless otherwise stated, bulleted items in the requirements and measures are items that are linked with an “or,” and numbered items are items that are linked with an “and.”~~

~~Many references in the Applicability section use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the BES. A review of UFLS tolerances defined within Regional Reliability Standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.~~

B. Requirements and Measures

- R1.** Each Responsible Entity shall review and obtain CIP Senior Manager approval at least once every 15 calendar months for one or more documented cyber security policies that collectively address the following topics: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*
- 1.1.** For its high impact and medium impact BES Cyber Systems, if any:
 - 1.1.1.** Personnel and training (CIP-004);
 - 1.1.2.** Electronic Security Perimeters (CIP-005) including Interactive Remote Access;
 - 1.1.3.** Physical security of BES Cyber Systems (CIP-006);
 - 1.1.4.** System security management (CIP-007);
 - 1.1.5.** Incident reporting and response planning (CIP-008);
 - 1.1.6.** Recovery plans for BES Cyber Systems (CIP-009);
 - 1.1.7.** Configuration change management and vulnerability assessments (CIP-010);
 - 1.1.8.** Information protection (CIP-011); and
 - 1.1.9.** Declaring and responding to CIP Exceptional Circumstances.
 - 1.2.** For its assets identified in CIP-002 containing low impact BES Cyber Systems, if any:
 - 1.2.1.** Cyber security awareness;
 - 1.2.2.** Physical security controls;
 - 1.2.3.** Electronic access controls;
 - 1.2.4.** Cyber Security Incident response;
 - 1.2.5.** Transient Cyber Assets and Removable Media malicious code risk mitigation;~~and~~
 - 1.2.6. Vendor remote access; and**
 - ~~1.2.6.1.2.7.~~** Declaring and responding to CIP Exceptional Circumstances.
- M1.** Examples of evidence may include, but are not limited to, policy documents; revision history, records of review, or workflow evidence from a document management system that indicate review of each cyber security policy at least once every 15 calendar months; and documented approval by the CIP Senior Manager for each cyber security policy.
- R2.** Each Responsible Entity with at least one asset identified in CIP-002 containing low impact BES Cyber Systems shall implement one or more documented cyber security

plan(s) for its low impact BES Cyber Systems that include the sections in Attachment 1. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

Note: An inventory, list, or discrete identification of low impact BES Cyber Systems or their BES Cyber Assets is not required. Lists of authorized users are not required.

- M2.** Evidence shall include each of the documented cyber security plan(s) that collectively include each of the sections in Attachment 1 and additional evidence to demonstrate implementation of the cyber security plan(s). Additional examples of evidence per section are located in Attachment 2.
- R3.** Each Responsible Entity shall identify a CIP Senior Manager by name and document any change within 30 calendar days of the change. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*
- M3.** An example of evidence may include, but is not limited to, a dated and approved document from a high level official designating the name of the individual identified as the CIP Senior Manager.
- R4.** The Responsible Entity shall implement a documented process to delegate authority, unless no delegations are used. Where allowed by the CIP Standards, the CIP Senior Manager may delegate authority for specific actions to a delegate or delegates. These delegations shall be documented, including the name or title of the delegate, the specific actions delegated, and the date of the delegation; approved by the CIP Senior Manager; and updated within 30 days of any change to the delegation. Delegation changes do not need to be reinstated with a change to the delegator. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*
- M4.** An example of evidence may include, but is not limited to, a dated document, approved by the CIP Senior Manager, listing individuals (by name or title) who are delegated the authority to approve or authorize specifically identified items.

C. Compliance

1. Compliance Monitoring Process

~~1.1.~~ Compliance Enforcement Authority:

~~1.2.1.1.~~ 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.

~~1.3.1.2.~~ **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 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.

~~1.4.1.3.~~ **Compliance Monitoring and Enforcement Program Assessment Processes:** As defined in the NERC Rules of Procedure, “Compliance Monitoring and Enforcement Program” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

- ~~Compliance Audits~~
- ~~Self-Certifications~~
- ~~Spot Checking~~
- ~~Compliance Investigations~~
- ~~Self-Reporting~~

- ~~Complaints~~

~~1.5. Additional Compliance Information:~~

~~1.6. None.~~

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003- ~~X8~~)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	Medium	The Responsible Entity documented and implemented one or more cyber security policies for its high impact and medium impact BES Cyber Systems, but did not address one of the nine topics required by R1. (R1.1) OR The Responsible Entity did not complete its review of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 within 15 calendar months but did complete this review in less than or equal to 16 calendar months of the previous review. (R1.1)	The Responsible Entity documented and implemented one or more cyber security policies for its high impact and medium impact BES Cyber Systems, but did not address two of the nine topics required by R1. (R1.1) OR The Responsible Entity did not complete its review of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 within 16 calendar months but did complete this review in less than or equal to 17 calendar months of the previous review. (R1.1)	The Responsible Entity documented and implemented one or more cyber security policies for its high impact and medium impact BES Cyber Systems, but did not address three of the nine topics required by R1. (R1.1) OR The Responsible Entity did not complete its review of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 within 17 calendar months but did complete this review in less than or equal to 18 calendar months of the previous review. (R1.1)	The Responsible Entity documented and implemented one or more cyber security policies for its high impact and medium impact BES Cyber Systems, but did not address four or more of the nine topics required by R1. (R1.1) OR The Responsible Entity did not have any documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1. (R1.1) OR The Responsible Entity did not complete its review of the one or more documented cyber security policies

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003- ~~X8~~)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 by the CIP Senior Manager within 15 calendar months but did complete this approval in less than or equal to 16 calendar months of the previous approval. (R1.1) OR The Responsible Entity documented one or more cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems, but did not address one of	OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 by the CIP Senior Manager within 16 calendar months but did complete this approval in less than or equal to 17 calendar months of the previous approval. (R1.1) OR The Responsible Entity documented one or more cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems, but did not address two of	OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 by the CIP Senior Manager within 17 calendar months but did complete this approval in less than or equal to 18 calendar months of the previous approval. (R1) OR The Responsible Entity documented one or more cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems, but did not address three	as required by R1 within 18 calendar months of the previous review. (R1) OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 by the CIP Senior Manager within 18 calendar months of the previous approval. (R1.1) OR The Responsible Entity documented one or more cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems, but did not address four or more of the ~~six~~<u>seven</u>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003- ~~X8~~)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			the ~~six~~-seven topics required by R1. (R1.2) OR The Responsible Entity did not complete its review of the one or more documented cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems as required by Requirement R1 within 15 calendar months but did complete this review in less than or equal to 16 calendar months of the previous review. (R1.2) OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber	the ~~six~~-seven topics required by R1. (R1.2) OR The Responsible Entity did not complete its review of the one or more documented cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems as required by Requirement R1 within 16 calendar months but did complete this review in less than or equal to 17 calendar months of the previous review. (R1.2) OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber	of the ~~six~~-seven topics required by R1. (R1.2) OR The Responsible Entity did not complete its review of the one or more documented cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems as required by R1 within 17 calendar months but did complete this review in less than or equal to 18 calendar months of the previous review. (R1.2) OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems as required by	topics required by R1. (R1.2) OR The Responsible Entity did not have any documented cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems as required by R1. (R1.2) OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems as required by Requirement R1 by the CIP Senior Manager within 18 calendar months of the previous approval. (R1.2)

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003- ~~X8~~)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Systems as required by Requirement R1 by the CIP Senior Manager within 15 calendar months but did not complete this approval in less than or equal to 16 calendar months of the previous approval. (R1.2)	Systems as required by Requirement R1 by the CIP Senior Manager within 16 calendar months but did not complete this approval in less than or equal to 17 calendar months of the previous approval. (R1.2)	Requirement R1 by the CIP Senior Manager within 17 calendar months but did not complete this approval in less than or equal to 18 calendar months of the previous approval. (R1.2)	
R2	Operations Planning	Lower	The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to document cyber security awareness according to Requirement R2, Attachment 1, Section 1. (R2) OR The Responsible Entity implemented electronic access controls but failed to document its cyber	The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to reinforce cyber security practices at least once every 15 calendar months according to Requirement R2, Attachment 1, Section 1. (R2) OR The Responsible Entity documented its cyber security plan(s) for its	The Responsible Entity documented the physical access controls for its assets containing low impact BES Cyber Systems, but failed to implement the physical security controls according to Requirement R2, Attachment 1, Section 2. (R2) OR The Responsible Entity documented its cyber security plan(s) for electronic access controls for its assets	The Responsible Entity failed to document and implement one or more cyber security plan(s) for its assets containing low impact BES Cyber Systems according to Requirement R2, Attachment 1. (R2)

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003- ~~X8~~)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			security plan(s) for electronic access controls according to Requirement R2, Attachment 1, Section 3. (R2) OR The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to document one or more Cyber Security Incident response plan(s) according to Requirement R2, Attachment 1, Section 4. (R2) OR The Responsible Entity documented one or more Cyber Security Incident response plan(s) within its cyber security plan(s) for its assets containing low	assets containing low impact BES Cyber Systems, but failed to document physical security controls according to Requirement R2, Attachment 1, Section 2. (R2) OR The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to document electronic access controls according to Requirement R2, Attachment 1, Section 3. (R2) OR The Responsible Entity documented its cyber security plan(s) for electronic access controls but failed to	containing low impact BES Cyber Systems, but failed to permit only necessary inbound and outbound electronic access controls according to Requirement R2, Attachment 1, Section 3.1. (R2) OR The Responsible Entity documented one or more Cyber Security Incident response plan(s) within its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to test each Cyber Security Incident response plan(s) at least once every 36 calendar months according to Requirement R2,	

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003- ~~X8~~)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			impact BES Cyber Systems, but failed to update each Cyber Security Incident response plan(s) within 180 days according to Requirement R2, Attachment 1, Section 4. (R2) OR The Responsible Entity documented its plan(s) for Transient Cyber Assets and Removable Media, but failed to manage its Transient Cyber Asset(s) according to Requirement R2, Attachment 1, Section 5.1. (R2) OR The Responsible Entity documented its plan(s) for Transient Cyber Assets, but failed to document the Removable Media	implement authentication for all Dial-up Connectivity that provides access to low impact BES Cyber System(s), per Cyber Asset capability according to Requirement R2, Attachment 1, Section 3.2 (R2) OR The Responsible Entity documented one or more incident response plan(s) within its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to include the process for identification, classification, and response to Cyber Security Incidents according to Requirement R2,	Attachment 1, Section 4. (R2) OR The Responsible Entity documented the determination of whether an identified Cyber Security Incident is a Reportable Cyber Security Incident, but failed to notify the Electricity Information Sharing and Analysis Center (E-ISAC) according to Requirement R2, Attachment 1, Section 4. (R2) OR The Responsible Entity documented its plan(s) for Transient Cyber Assets and Removable Media, but failed to implement mitigation for the introduction of malicious code for Transient Cyber Assets	

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003- ~~X8~~)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			section(s) according to Requirement R2, Attachment 1, Section 5.3. (R2) <u>OR</u> <u>The Responsible Entity implemented vendor remote access controls but failed to document its cyber security plan(s) for vendor remote access controls according to Requirement R2, Attachment 1, Section 6. (R2)</u>	Attachment 1, Section 4. (R2) OR The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to document the determination of whether an identified Cyber Security Incident is a Reportable Cyber Security Incident and subsequent notification to the Electricity Information Sharing and Analysis Center (E-ISAC) according to Requirement R2, Attachment 1, Section 4. (R2) OR The Responsible Entity documented its plan(s) for Transient Cyber	managed by the Responsible Entity according to Requirement R2, Attachment 1, Section 5.1. (R2) OR The Responsible Entity documented its plan(s) for Transient Cyber Assets and Removable Media, but failed to implement mitigation for the introduction of malicious code for Transient Cyber Assets managed by a party other than the Responsible Entity according to Requirement R2, Attachment 1, Section 5.2. (R2) OR The Responsible Entity documented its plan(s) for Transient Cyber Assets and Removable	

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003- ~~X8~~)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				Assets and Removable Media, but failed to document mitigation for the introduction of malicious code for Transient Cyber Assets managed by the Responsible Entity according to Requirement R2, Attachment 1, Sections 5.1 and 5.3. (R2) OR The Responsible Entity documented its plan(s) for Transient Cyber Assets and Removable Media, but failed to document mitigation for the introduction of malicious code for Transient Cyber Assets managed by a party other than the Responsible Entity according to Requirement R2,	Media, but failed to implement mitigation for the threat of detected malicious code on the Removable Media prior to connecting Removable Media to a low impact BES Cyber System according to Requirement R2, Attachment 1, Section 5.3. (R2) <u>OR</u> <u>The Responsible Entity failed to document and implement its cyber security plan(s) for vendor remote access controls according to Requirement R2, Attachment 1, Section 6. (R2)</u>	

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-X8)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				Attachment 1, Section 5.2. (R2) OR The Responsible Entity documented its plan(s) for Transient Cyber Assets and Removable Media, but failed to implement the Removable Media section(s) according to Requirement R2, Attachment 1, Section 5.3. (R2) <u>OR</u> <u>The Responsible Entity documented its cyber security plan(s) for vendor remote access controls, but failed to implement vendor remote access controls according to Requirement R2, Attachment 1, Section 6. (R2)</u>		

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003- ~~X8~~)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	Operations Planning	Medium	The Responsible Entity has identified by name a CIP Senior Manager, but did not document changes to the CIP Senior Manager within 30 calendar days but did document this change in less than 40 calendar days of the change. (R3)	The Responsible Entity has identified by name a CIP Senior Manager, but did not document changes to the CIP Senior Manager within 40 calendar days but did document this change in less than 50 calendar days of the change. (R3)	The Responsible Entity has identified by name a CIP Senior Manager, but did not document changes to the CIP Senior Manager within 50 calendar days but did document this change in less than 60 calendar days of the change. (R3)	The Responsible Entity has not identified, by name, a CIP Senior Manager. OR The Responsible Entity has identified by name a CIP Senior Manager, but did not document changes to the CIP Senior Manager within 60 calendar days of the change. (R3)
R4	Operations Planning	Lower	The Responsible Entity has identified a delegate by name, title, date of delegation, and specific actions delegated, but did not document changes to the delegate within 30 calendar days but did document this change in less than 40 calendar days of the change. (R4)	The Responsible Entity has identified a delegate by name, title, date of delegation, and specific actions delegated, but did not document changes to the delegate within 40 calendar days but did document this change in less than 50 calendar days of the change. (R4)	The Responsible Entity has identified a delegate by name, title, date of delegation, and specific actions delegated, but did not document changes to the delegate within 50 calendar days but did document this change in less than 60 calendar days of the change. (R4)	The Responsible Entity has used delegated authority for actions where allowed by the CIP Standards, but does not have a process to delegate actions from the CIP Senior Manager. (R4) OR The Responsible Entity has identified a delegate by name, title, date of

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003- ~~X8~~)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						delegation, and specific actions delegated, but did not document changes to the delegate within 60 calendar days of the change. (R4)

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change “Control Center” to “control center.”	3/24/06
2	9/30/09	Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3	12/16/09	Updated Version Number from -2 to -3 In Requirement 1.6, deleted the sentence pertaining to removing component or system from service in order to perform testing, in response to FERC order issued September 30, 2009.	
3	12/16/09	Approved by the NERC Board of Trustees.	
3	3/31/10	Approved by FERC.	
4	1/24/11	Approved by the NERC Board of Trustees.	
5	11/26/12	Adopted by the NERC Board of Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.
5	11/22/13	FERC Order issued approving CIP-003-5.	
6	11/13/14	Adopted by the NERC Board of Trustees.	Addressed two FERC directives from

Version	Date	Action	Change Tracking
			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-003-6. Docket No. RM15-14-000	
7	2/9/17	Adopted by the NERC Board of Trustees.	Revised to address FERC Order No. 822 directives regarding (1) the definition of LERC and (2) transient devices.
7	4/19/18	FERC Order issued approving CIP-003-7. Docket No. RM17-11-000	
8	5/9/19	Adopted by the NERC Board of Trustees.	Removed SPS references. Revised to address FERC Order No. 843 regarding mitigating the risk of malicious code.
8	7/31/2019	FERC Order issued approving CIP-003-8. Docket No. RD19-5-000.	

Attachment 1

Required Sections for Cyber Security Plan(s) for Assets Containing Low Impact BES Cyber Systems

Responsible Entities shall include each of the sections provided below in the cyber security plan(s) required under Requirement R2.

Responsible Entities with multiple-impact BES Cyber Systems ratings can utilize policies, procedures, and processes for their high or medium impact BES Cyber Systems to fulfill the sections for the development of low impact cyber security plan(s). Each Responsible Entity can develop a cyber security plan(s) either by individual asset or groups of assets.

Section 1. Cyber Security Awareness: Each Responsible Entity shall reinforce, at least once every 15 calendar months, cyber security practices (which may include associated physical security practices).

Section 2. Physical Security Controls: Each Responsible Entity shall control physical access, based on need as determined by the Responsible Entity, to (1) the asset or the locations of the low impact BES Cyber Systems within the asset, and (2) the Cyber Asset(s), as specified by the Responsible Entity, that provide electronic access control(s) implemented for Section 3.1, if any.

Section 3. Electronic Access Controls: For each asset containing low impact BES Cyber System(s) identified pursuant to CIP-002, the Responsible Entity shall implement electronic access controls to:

- 3.1** Permit only necessary inbound and outbound electronic access as determined by the Responsible Entity for any communications that are:
 - i. between a low impact BES Cyber System(s) and a Cyber Asset(s) outside the asset containing low impact BES Cyber System(s);
 - ii. using a routable protocol when entering or leaving the asset containing the low impact BES Cyber System(s); and
 - iii. not used for time-sensitive protection or control functions between intelligent electronic devices (e.g., communications using protocol IEC TR-61850-90-5 R-GOOSE).
- 3.2** Authenticate all Dial-up Connectivity, if any, that provides access to low impact BES Cyber System(s), per Cyber Asset capability.

Section 4. Cyber Security Incident Response: Each Responsible Entity shall have one or more Cyber Security Incident response plan(s), either by asset or group of assets, which shall include:

- 4.1** Identification, classification, and response to Cyber Security Incidents;

- 4.2 Determination of whether an identified Cyber Security Incident is a Reportable Cyber Security Incident and subsequent notification to the Electricity Information Sharing and Analysis Center (E-ISAC), unless prohibited by law;
- 4.3 Identification of the roles and responsibilities for Cyber Security Incident response by groups or individuals;
- 4.4 Incident handling for Cyber Security Incidents;
- 4.5 Testing the Cyber Security Incident response plan(s) at least once every 36 calendar months by: (1) responding to an actual Reportable Cyber Security Incident; (2) using a drill or tabletop exercise of a Reportable Cyber Security Incident; or (3) using an operational exercise of a Reportable Cyber Security Incident; and
- 4.6 Updating the Cyber Security Incident response plan(s), if needed, within 180 calendar days after completion of a Cyber Security Incident response plan(s) test or actual Reportable Cyber Security Incident.

Section 5. Transient Cyber Asset and Removable Media Malicious Code Risk Mitigation: Each Responsible Entity shall implement, except under CIP Exceptional Circumstances, one or more plan(s) to achieve the objective of mitigating the risk of the introduction of malicious code to low impact BES Cyber Systems through the use of Transient Cyber Assets or Removable Media. The plan(s) shall include:

- 5.1 For Transient Cyber Asset(s) managed by the Responsible Entity, if any, the use of one or a combination of the following in an ongoing or on-demand manner (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.
- 5.2 For Transient Cyber Asset(s) managed by a party other than the Responsible Entity, if any:
 - 5.2.1 Use one or a combination of the following prior to connecting the Transient Cyber Asset to a low impact BES Cyber System (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 the introduction of malicious code.

5.2.2 For any method used pursuant to 5.2.1, Responsible Entities shall determine whether any additional mitigation actions are necessary and implement such actions prior to connecting the Transient Cyber Asset.

5.3 For Removable Media, the use of each of the following:

5.3.1 Method(s) to detect malicious code on Removable Media using a Cyber Asset other than a BES Cyber System; and

5.3.2 Mitigation of the threat of detected malicious code on the Removable Media prior to connecting Removable Media to a low impact BES Cyber System.

Section 6: -Vendor remote access: For assets containing low impact BES Cyber System(s) identified pursuant to CIP-002, the Responsible Entity shall implement a process to mitigate risks associated with vendor remote access (including interactive and system-to-system access) to low impact BES Cyber Systems that includes:

6.1 —Having one or more method(s) for determining vendor remote access sessions;

6.2 -Having one or more method(s) for detecting known or suspected malicious communications for both inbound and outbound communications; and

6.3 -Having one or more method(s) for disabling vendor remote access.

Attachment 2

Examples of Evidence for Cyber Security Plan(s) for Assets Containing Low Impact BES Cyber Systems

Section 1. Cyber Security Awareness: An example of evidence for Section 1 may include, but is not limited to, documentation that the reinforcement of cyber security practices occurred at least once every 15 calendar months. The evidence could be documentation through one or more of the following methods:

- Direct communications (for example, e-mails, memos, or computer-based training);
- Indirect communications (for example, posters, intranet, or brochures); or
- Management support and reinforcement (for example, presentations or meetings).

Section 2. Physical Security Controls: Examples of evidence for Section 2 may include, but are not limited to:

- Documentation of the selected access control(s) (e.g., card key, locks, perimeter controls), monitoring controls (e.g., alarm systems, human observation), or other operational, procedural, or technical physical security controls that control physical access to both:
 - a. The asset, if any, or the locations of the low impact BES Cyber Systems within the asset; and
 - b. The Cyber Asset(s) specified by the Responsible Entity that provide(s) electronic access controls implemented for Attachment 1, Section 3.1, if any.

Section 3. Electronic Access Controls: Examples of evidence for Section 3 may include, but are not limited to:

1. Documentation showing that at each asset or group of assets containing low impact BES Cyber Systems, routable communication between a low impact BES Cyber System(s) and a Cyber Asset(s) outside the asset is restricted by electronic access controls to permit only inbound and outbound electronic access that the Responsible Entity deems necessary, except where an entity provides rationale that communication is used for time-sensitive protection or control functions between intelligent electronic devices. Examples of such documentation may include, but are not limited to representative diagrams that illustrate control of inbound and outbound communication(s) between the low impact BES Cyber System(s) and a Cyber Asset(s) outside the asset containing low impact BES Cyber System(s) or lists of implemented electronic access controls (e.g., access control lists restricting IP addresses, ports, or services; implementing unidirectional gateways).

2. Documentation of authentication for Dial-up Connectivity (e.g., dial out only to a preprogrammed number to deliver data, dial-back modems, modems that must be remotely controlled by the control center or control room, or access control on the BES Cyber System).

Section 4. Cyber Security Incident Response: An example of evidence for Section 4 may include, but is not limited to, dated documentation, such as policies, procedures, or process documents of one or more Cyber Security Incident response plan(s) developed either by asset or group of assets that include the following processes:

1. to identify, classify, and respond to Cyber Security Incidents; to determine whether an identified Cyber Security Incident is a Reportable Cyber Security Incident and for notifying the Electricity Information Sharing and Analysis Center (E-ISAC);
2. to identify and document the roles and responsibilities for Cyber Security Incident response by groups or individuals (e.g., initiating, documenting, monitoring, reporting, etc.);
3. for incident handling of a Cyber Security Incident (e.g., containment, eradication, or recovery/incident resolution);
4. for testing the plan(s) along with the dated documentation that a test has been completed at least once every 36 calendar months; and
5. to update, as needed, Cyber Security Incident response plan(s) within 180 calendar days after completion of a test or actual Reportable Cyber Security Incident.

Section 5. Transient Cyber Asset and Removable Media Malicious Code Risk Mitigation:

1. Examples of evidence for Section 5.1 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.
2. Examples of evidence for Section 5.2.1 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 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.

Examples of evidence for Attachment 1, Section 5.2.2 may include, but are not limited to, documentation from change management systems, electronic mail, or contracts that identifies a review to determine whether additional mitigation is necessary and has been implemented prior to connecting the Transient Cyber Asset managed by a party other than the Responsible Entity.

3. Examples of evidence for Section 5.3.1 may include, but are not limited to, documented process(es) of the method(s) used to detect malicious code such as results of scan settings for Removable Media, or implementation of on-demand scanning. Examples of evidence for Section 5.3.2 may include, but are not limited to, 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 the 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.

Section 6: Examples of evidence showing the implementation of the process for Section 6 may include, but are not limited to:

1. Documentation showing:

- steps to preauthorize access;
- alerts generated by vendor log on;
- session monitoring;
- Security Information Management logging alerts;
- time-of-need session initiation;
- session recording;
- system logs; or
- other operational, procedural or technical controls.

2. Documentation of configuration of security alerts; security alerts or logging relative to activities ~~or configuration of security alerts~~ during the communication from items such as:

- Firewall policies;
- Intrusion Detection System (IDS)/Intrusion Prevention System (IPS);
- Virtual Private Network (VPN) hosts;
- manual review of logs; or
- other operational, procedural or technical controls.

3. Documentation showing methods to disable vendor remote access such as:

- disabling vendor remote access user or system accounts;
- disabling inbound and/or outbound hardware or software ports, services, or access permissions on applications, firewall, IDS/IPS, router, switch, VPN, Remote Desktop, remote control, or other hardware or software used for providing active vendor remote access;
- disabling communications protocols (such as IP) used for systems which establish and/or maintain active vendor remote access;
- Removing physical layer connectivity (e.g., disconnect an Ethernet cable, power down equipment);
- administrative control documentation listing the methods, steps, systems used to disable active vendor remote access; or
- other operational, procedural or technical controls.

Guidelines and Technical Basis

Section 4—Scope of Applicability of the CIP Cyber Security Standards

Section “4. Applicability” of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section “4.1. Functional Entities” is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in Section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in Section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2.

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in Section 4.1, that is subject to the requirements of the standard. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards.

Requirement R1:

In developing policies in compliance with Requirement R1, the number of policies and their content should be guided by a Responsible Entity's management structure and operating conditions. Policies might be included as part of a general information security program for the entire organization, or as components of specific programs. The Responsible Entity has the flexibility to develop a single comprehensive cyber security policy covering the required topics, or it may choose to develop a single high-level umbrella policy and provide additional policy detail in lower level documents in its documentation hierarchy. In the case of a high-level umbrella policy, the Responsible Entity would be expected to provide the high-level policy as well as the additional documentation in order to demonstrate compliance with CIP-003-8, Requirement R1.

If a Responsible Entity has any high or medium impact BES Cyber Systems, the one or more cyber security policies must cover the nine subject matter areas required by CIP-003-8, Requirement R1, Part 1.1. If a Responsible Entity has identified from CIP-002 any assets containing low impact BES Cyber Systems, the one or more cyber security policies must cover the six subject matter areas required by Requirement R1, Part 1.2.

Responsible Entities that have multiple impact rated BES Cyber Systems are not required to create separate cyber security policies for high, medium, or low impact BES Cyber Systems. The Responsible Entities have the flexibility to develop policies that cover all three impact ratings.

Implementation of the cyber security policy is not specifically included in CIP-003-8, Requirement R1 as it is envisioned that the implementation of this policy is evidenced through successful implementation of CIP-003 through CIP-011. However, Responsible Entities are encouraged not to limit the scope of their cyber security policies to only those requirements in NERC cyber security Reliability Standards, but to develop a holistic cyber

~~security policy appropriate for its organization. Elements of a policy that extend beyond the scope of NERC's cyber security Reliability Standards will not be considered candidates for potential violations although they will help demonstrate the organization's internal culture of compliance and posture towards cyber security.~~

~~For Part 1.1, the Responsible Entity may consider the following for each of the required topics in its one or more cyber security policies for medium and high impact BES Cyber Systems, if any:~~

~~1.1.1 Personnel and training (CIP-004)~~

- ~~• Organization position on acceptable background investigations~~
- ~~• Identification of possible disciplinary action for violating this policy~~
- ~~• Account management~~

~~1.1.2 Electronic Security Perimeters (CIP-005) including Interactive Remote Access~~

- ~~• Organization stance on use of wireless networks~~
- ~~• Identification of acceptable authentication methods~~
- ~~• Identification of trusted and untrusted resources~~
- ~~• Monitoring and logging of ingress and egress at Electronic Access Points~~
- ~~• Maintaining up-to-date anti-malware software before initiating Interactive Remote Access~~
- ~~• Maintaining up-to-date patch levels for operating systems and applications used to initiate Interactive Remote Access~~
- ~~• Disabling VPN "split tunneling" or "dual-homed" workstations before initiating Interactive Remote Access~~
- ~~• For vendors, contractors, or consultants: include language in contracts that requires adherence to the Responsible Entity's Interactive Remote Access controls~~

~~1.1.3 Physical security of BES Cyber Systems (CIP-006)~~

- ~~• Strategy for protecting Cyber Assets from unauthorized physical access~~
- ~~• Acceptable physical access control methods~~
- ~~• Monitoring and logging of physical ingress~~

~~1.1.4 System security management (CIP-007)~~

- ~~• Strategies for system hardening~~
- ~~• Acceptable methods of authentication and access control~~
- ~~• Password policies including length, complexity, enforcement, prevention of brute force attempts~~
- ~~• Monitoring and logging of BES Cyber Systems~~

~~1.1.5 Incident reporting and response planning (CIP-008)~~

- ~~• Recognition of Cyber Security Incidents~~
- ~~• Appropriate notifications upon discovery of an incident~~
- ~~• Obligations to report Cyber Security Incidents~~

~~1.1.6 Recovery plans for BES Cyber Systems (CIP-009)~~

- ~~• Availability of spare components~~
- ~~• Availability of system backups~~

~~1.1.7 Configuration change management and vulnerability assessments (CIP-010)~~

- ~~• Initiation of change requests~~
- ~~• Approval of changes~~
- ~~• Break fix processes~~

~~1.1.8 Information protection (CIP-011)~~

- ~~• Information access control methods~~
- ~~• Notification of unauthorized information disclosure~~
- ~~• Information access on a need-to-know basis~~

~~1.1.9 Declaring and responding to CIP Exceptional Circumstances~~

- ~~• Processes to invoke special procedures in the event of a CIP Exceptional Circumstance~~
- ~~• Processes to allow for exceptions to policy that do not violate CIP requirements~~

~~For Part 1.2, the Responsible Entity may consider the following for each of the required topics in its one or more cyber security policies for assets containing low impact BES Cyber Systems, if any:~~

~~1.2.1 Cyber security awareness~~

- ~~• Method(s) for delivery of security awareness~~
- ~~• Identification of groups to receive cyber security awareness~~

~~1.2.2 Physical security controls~~

- ~~• Acceptable approach(es) for selection of physical security control(s)~~

~~1.2.3 Electronic access controls~~

- ~~• Acceptable approach(es) for selection of electronic access control(s)~~

~~1.2.4 Cyber Security Incident response~~

- ~~• Recognition of Cyber Security Incidents~~

- ~~Appropriate notifications upon discovery of an incident~~
- ~~Obligations to report Cyber Security Incidents~~

~~1.2.5 Transient Cyber Assets and Removable Media Malicious Code Risk Mitigation~~

- ~~Acceptable use of Transient Cyber Asset(s) and Removable Media~~
- ~~Method(s) to mitigate the risk of the introduction of malicious code to low impact BES Cyber Systems from Transient Cyber Assets and Removable Media~~
- ~~Method(s) to request Transient Cyber Asset and Removable Media~~

~~1.2.6 Declaring and responding to CIP Exceptional Circumstances~~

- ~~Process(es) to declare a CIP Exceptional Circumstance~~
- ~~Process(es) to respond to a declared CIP Exceptional Circumstance~~

~~Requirements relating to exceptions to a Responsible Entity's security policies were removed because it is a general management issue that is not within the scope of a reliability requirement. It is an internal policy requirement and not a reliability requirement. However, Responsible Entities are encouraged to continue this practice as a component of their cyber security policies.~~

~~In this and all subsequent required approvals in the NERC CIP Reliability Standards, the Responsible Entity may elect to use hardcopy or electronic approvals to the extent that there is sufficient evidence to ensure the authenticity of the approving party.~~

Requirement R2:

~~The intent of Requirement R2 is for each Responsible Entity to create, document, and implement one or more cyber security plan(s) that address the security objective for the protection of low impact BES Cyber Systems. The required protections are designed to be part of a program that covers the low impact BES Cyber Systems collectively at an asset level (based on the list of assets containing low impact BES Cyber Systems identified in CIP-002), but not at an individual device or system level.~~

Requirement R2, Attachment 1

As noted, Attachment 1 contains the sections that must be included in the cyber security plan(s). The intent is to allow entities that have a combination of high, medium, and low impact BES Cyber Systems the flexibility to choose, if desired, to cover their low impact BES Cyber Systems (or any subset) under their programs used for the high or medium impact BES Cyber Systems rather than maintain two separate programs. The purpose of the cyber security plan(s) in Requirement R2 is for Responsible Entities to use the cyber security plan(s) as a means of documenting their approaches to meeting the subject matter areas. The cyber security plan(s) can be used to reference other policies and procedures that demonstrate “how” the Responsible Entity is meeting each of the subject matter areas, or Responsible Entities can develop comprehensive cyber security plan(s) that contain all of the detailed implementation content solely within the cyber security plan itself. To meet the obligation for the cyber security plan, the expectation is that the cyber security plan contains or references sufficient details to address the implementation of each of the required subject matters areas.

Guidance for each of the subject matter areas of Attachment 1 is provided below:

Requirement R2, Attachment 1, Section 1—Cyber Security Awareness

The intent of the cyber security awareness program is for entities to reinforce good cyber security practices with their personnel at least once every 15 calendar months. The entity has the discretion to determine the topics to be addressed and the manner in which it will communicate these topics. As evidence of compliance, the Responsible Entity should be able to produce the awareness material that was delivered according to the delivery method(s) (e.g., posters, emails, or topics at staff meetings, etc.). The standard drafting team does not intend for Responsible Entities to be required to maintain lists of recipients and track the reception of the awareness material by personnel.

Although the focus of the awareness is cyber security, it does not mean that only technology-related topics can be included in the program. Appropriate physical security topics (e.g., tailgating awareness and protection of badges for physical security, or “If you see something, say something” campaigns, etc.) are valid for cyber security awareness. The intent is to cover topics concerning any aspect of the protection of BES Cyber Systems.

Requirement R2, Attachment 1, Section 2—Physical Security Controls

The Responsible Entity must document and implement methods to control physical access to (1) the asset or the locations of low impact BES Cyber Systems within the asset, and (2) Cyber Assets that implement the electronic access control(s) specified by the Responsible Entity in Attachment 1, Section 3.1, if any. If these Cyber Assets implementing the electronic access controls are located within the same asset as the low impact BES Cyber Asset(s) and inherit the same physical access controls and the same need as outlined in Section 2, this may be noted by the Responsible Entity in either its policies or cyber security plan(s) to avoid duplicate documentation of the same controls.

The Responsible Entity has the flexibility to select the methods used to meet the objective of controlling physical access to (1) the asset(s) containing low impact BES Cyber System(s) or the low impact BES Cyber Systems themselves and (2) the electronic access control Cyber Assets specified by the Responsible Entity, if any. The Responsible Entity may use one or a

~~combination of physical access controls, monitoring controls, or other operational, procedural, or technical physical security controls. Entities may use perimeter controls (e.g., fences with locked gates, guards, or site access policies, etc.) or more granular areas of physical access control in areas where low impact BES Cyber Systems are located, such as control rooms or control houses.~~

~~The security objective is to control the physical access based on need as determined by the Responsible Entity. The need for physical access can be documented at the policy level. The standard drafting team did not intend to obligate an entity to specify a need for each physical access or authorization of an individual for physical access.~~

~~Monitoring as a physical security control can be used as a complement or an alternative to physical access control. Examples of monitoring controls include, but are not limited to: (1) alarm systems to detect motion or entry into a controlled area, or (2) human observation of a controlled area. Monitoring does not necessarily require logging and maintaining logs but could include monitoring that physical access has occurred or been attempted (e.g., door alarm, or human observation, etc.). The standard drafting team's intent is that the monitoring does not need to be per low impact BES Cyber System but should be at the appropriate level to meet the security objective of controlling physical access.~~

~~User authorization programs and lists of authorized users for physical access are not required although they are an option to meet the security objective.~~

Requirement R2, Attachment 1, Section 3—Electronic Access Controls

~~Section 3 requires the establishment of electronic access controls for assets containing low impact BES Cyber Systems when there is routable protocol communication or Dial-up Connectivity between Cyber Asset(s) outside of the asset containing the low impact BES Cyber System(s) and the low impact BES Cyber System(s) within such asset. The establishment of electronic access controls is intended to reduce the risks associated with uncontrolled communication using routable protocols or Dial-up Connectivity.~~

~~When implementing Attachment 1, Section 3.1, Responsible Entities should note that electronic access controls to permit only necessary inbound and outbound electronic access are required for communications when those communications meet all three of the criteria identified in Attachment 1, Section 3.1. The Responsible Entity should evaluate the communications and when all three criteria are met, the Responsible Entity must document and implement electronic access control(s).~~

~~When identifying electronic access controls, Responsible Entities are provided flexibility in the selection of the electronic access controls that meet their operational needs while meeting the security objective of allowing only necessary inbound and outbound electronic access to low impact BES Cyber Systems that use routable protocols between a low impact BES Cyber System(s) and Cyber Asset(s) outside the asset.~~

~~In essence, the intent is for Responsible Entities to determine whether there is communication between a low impact BES Cyber System(s) and a Cyber Asset(s) outside the asset containing low impact BES Cyber System(s) that uses a routable protocol when entering or leaving the asset or Dial-up Connectivity to the low impact BES Cyber System(s). Where such~~

~~communication is present, Responsible Entities should document and implement electronic access control(s). Where routable protocol communication for time-sensitive protection or control functions between intelligent electronic devices that meets the exclusion language is present, Responsible Entities should document that communication, but are not required to establish any specific electronic access controls.~~

~~The inputs to this requirement are the assets identified in CIP-002 as containing low impact BES Cyber System(s); therefore, the determination of routable protocol communications or Dial-up Connectivity is an attribute of the asset. However, it is not intended for communication that provides no access to or from the low impact BES Cyber System(s), but happens to be located at the asset with the low impact BES Cyber System(s), to be evaluated for electronic access controls.~~

Electronic Access Control Exclusion

~~In order to avoid future technology issues, the obligations for electronic access controls exclude communications between intelligent electronic devices that use routable communication protocols for time-sensitive protection or control functions, such as IEC TR-61850-90-5 R-GOOSE messaging. Time-sensitive in this context generally means functions that would be negatively impacted by the latency introduced in the communications by the required electronic access controls. This time-sensitivity exclusion does not apply to SCADA communications which typically operate on scan rates of 2 seconds or greater. While technically time-sensitive, SCADA communications over routable protocols can withstand the delay introduced by electronic access controls. Examples of excluded time-sensitive communications are those communications which may necessitate the tripping of a breaker within a few cycles. A Responsible Entity using this technology is not expected to implement the electronic access controls noted herein. This exception was included so as not to inhibit the functionality of the time-sensitive characteristics related to this technology and not to preclude the use of such time-sensitive reliability enhancing functions if they use a routable protocol in the future.~~

Considerations for Determining Routable Protocol Communications

~~To determine whether electronic access controls need to be implemented, the Responsible Entity has to determine whether there is communication between a low impact BES Cyber System(s) and a Cyber Asset(s) outside the asset containing the low impact BES Cyber System(s) that uses a routable protocol when entering or leaving the asset.~~

~~When determining whether a routable protocol is entering or leaving the asset containing the low impact BES Cyber System(s), Responsible Entities have flexibility in identifying an approach. One approach is for Responsible Entities to identify an “electronic boundary” associated with the asset containing low impact BES Cyber System(s). This is not an Electronic Security Perimeter *per se*, but a demarcation that demonstrates the routable protocol communication entering or leaving the asset between a low impact BES Cyber System and Cyber Asset(s) outside the asset to then have electronic access controls implemented. This electronic boundary may vary by asset type (Control Center, substation, generation resource) and the specific configuration of the asset. If this approach is used, the intent is for the Responsible Entity to define the electronic boundary such that the low impact BES Cyber System(s) located~~

at the asset are contained within the “electronic boundary.” This is strictly for determining which routable protocol communications and networks are internal or inside or local to the asset and which are external to or outside the asset.

Alternatively, the Responsible Entity may find the concepts of what is inside and outside to be intuitively obvious for a Cyber Asset(s) outside the asset containing low impact BES Cyber System(s) communicating to a low impact BES Cyber System(s) inside the asset. This may be the case when a low impact BES Cyber System(s) is communicating with a Cyber Asset many miles away and a clear and unambiguous demarcation exists. In this case, a Responsible Entity may decide not to identify an “electronic boundary,” but rather to simply leverage the unambiguous asset demarcation to ensure that the electronic access controls are placed between the low impact BES Cyber System(s) and the Cyber Asset(s) outside the asset.

Determining Electronic Access Controls

Once a Responsible Entity has determined that there is routable communication between a low impact BES Cyber System(s) and a Cyber Asset(s) outside the asset containing the low impact BES Cyber System(s) that uses a routable protocol when entering or leaving the asset containing the low impact BES Cyber System(s), the intent is for the Responsible Entity to document and implement its chosen electronic access control(s). The control(s) are intended to allow only “necessary” inbound and outbound electronic access as determined by the Responsible Entity. However the Responsible Entity chooses to document the inbound and outbound access permissions and the need, the intent is that the Responsible Entity is able to explain the reasons for the electronic access permitted. The reasoning for “necessary” inbound and outbound electronic access controls may be documented within the Responsible Entity’s cyber security plan(s), within a comment on an access control list, a database, spreadsheet or other policies or procedures associated with the electronic access controls.

Concept Diagrams

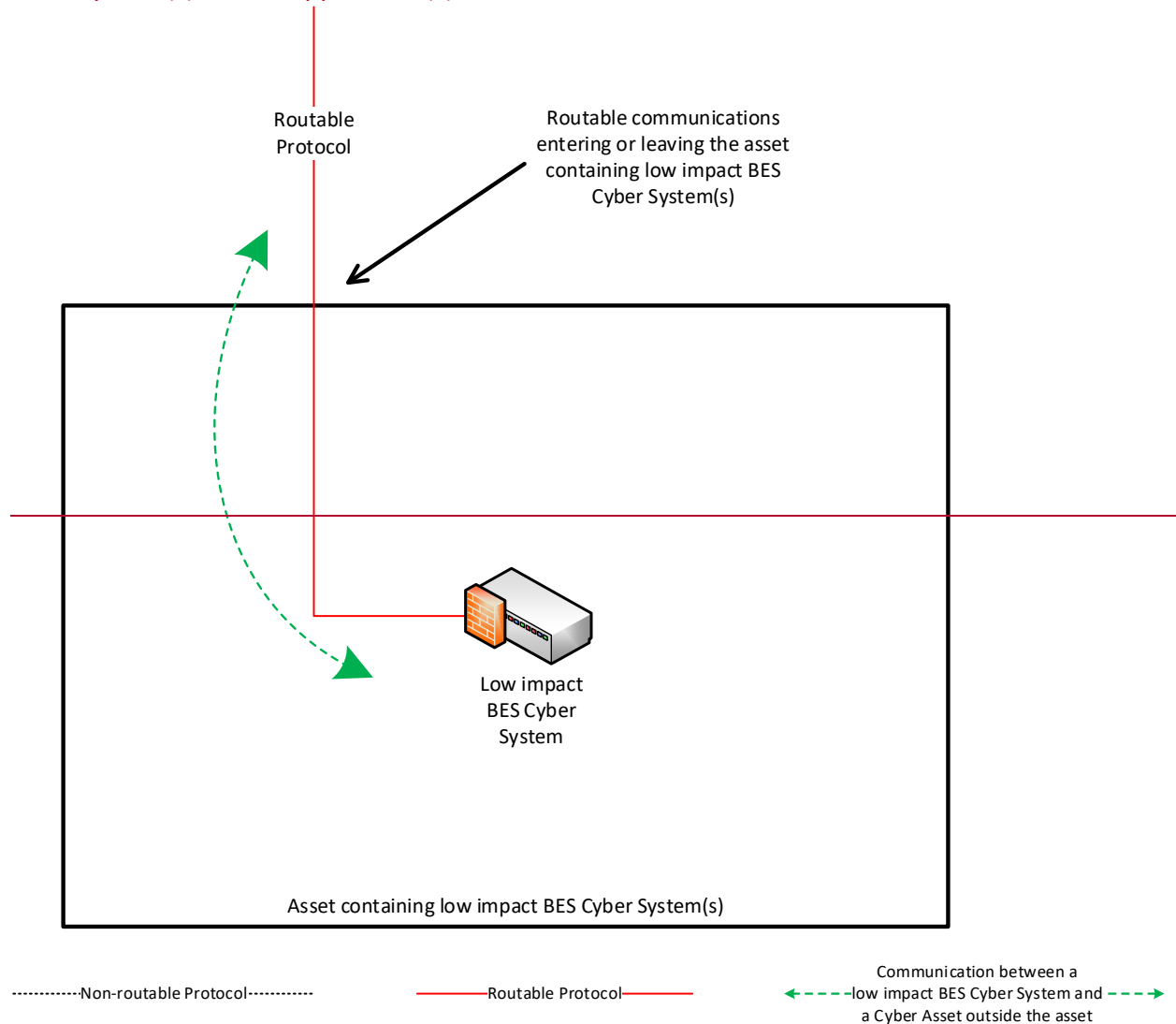
The diagrams on the following pages are provided as examples to illustrate various electronic access controls at a conceptual level. Regardless of the concepts or configurations chosen by the Responsible Entity, the intent is to achieve the security objective of permitting only necessary inbound and outbound electronic access for communication between low impact BES Cyber Systems and Cyber Asset(s) outside the asset containing the low impact BES Cyber System(s) using a routable protocol when entering or leaving the asset.

NOTE:

- This is not an exhaustive list of applicable concepts.
- The same legend is used in each diagram; however, the diagram may not contain all of the articles represented in the legend.

Reference Model 1—Host-based Inbound & Outbound Access Permissions

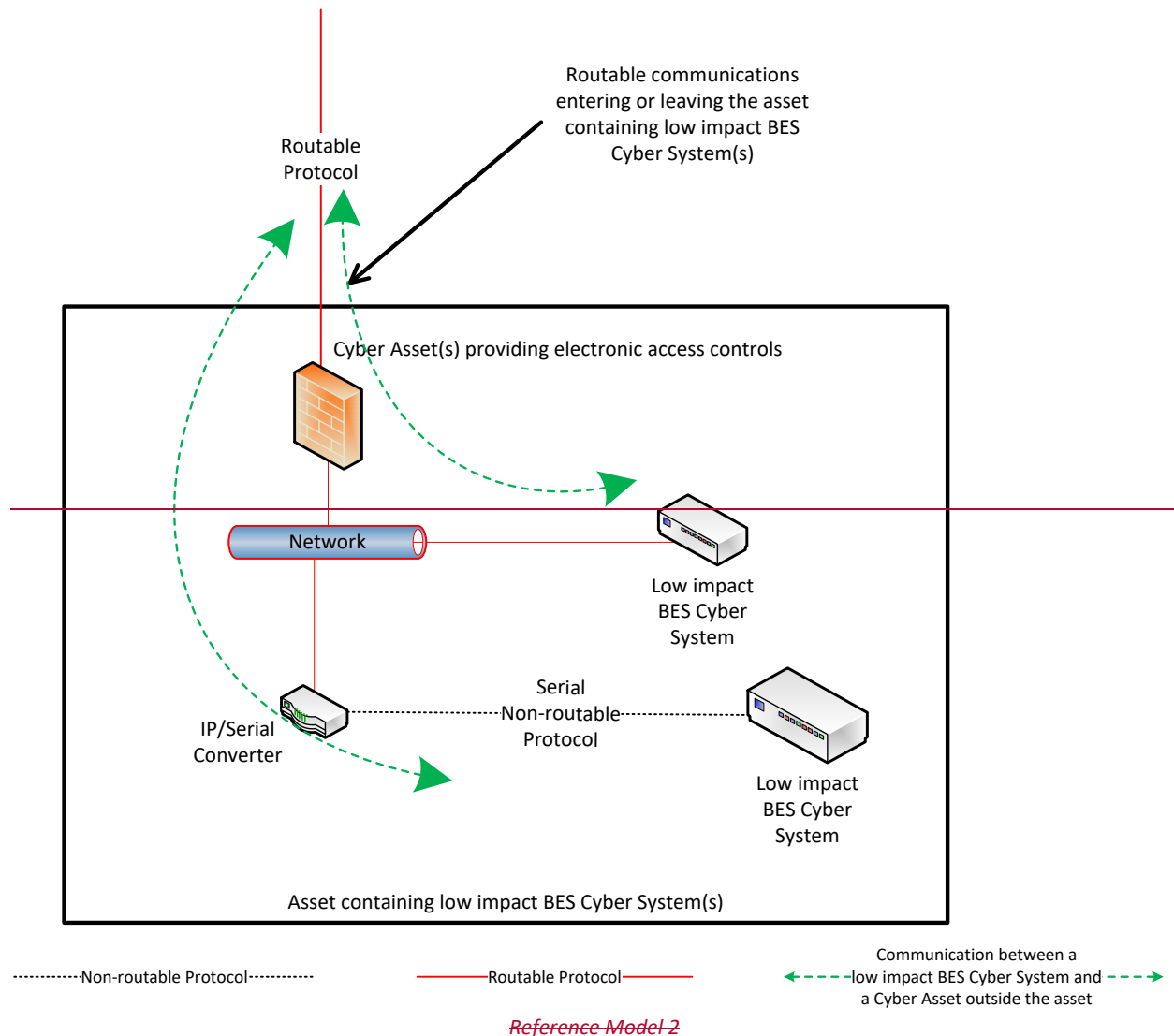
The Responsible Entity may choose to utilize a host-based firewall technology on the low impact BES Cyber System(s) itself that manages the inbound and outbound electronic access permissions so that only necessary inbound and outbound electronic access is allowed between the low impact BES Cyber System(s) and the Cyber Asset(s) outside the asset containing the low impact BES Cyber System(s). When permitting the inbound and outbound electronic access permissions using access control lists, the Responsible Entity could restrict communication(s) using source and destination addresses or ranges of addresses. Responsible Entities could also restrict communication(s) using ports or services based on the capability of the electronic access control, the low impact BES Cyber System(s), or the application(s).



Reference Model 1

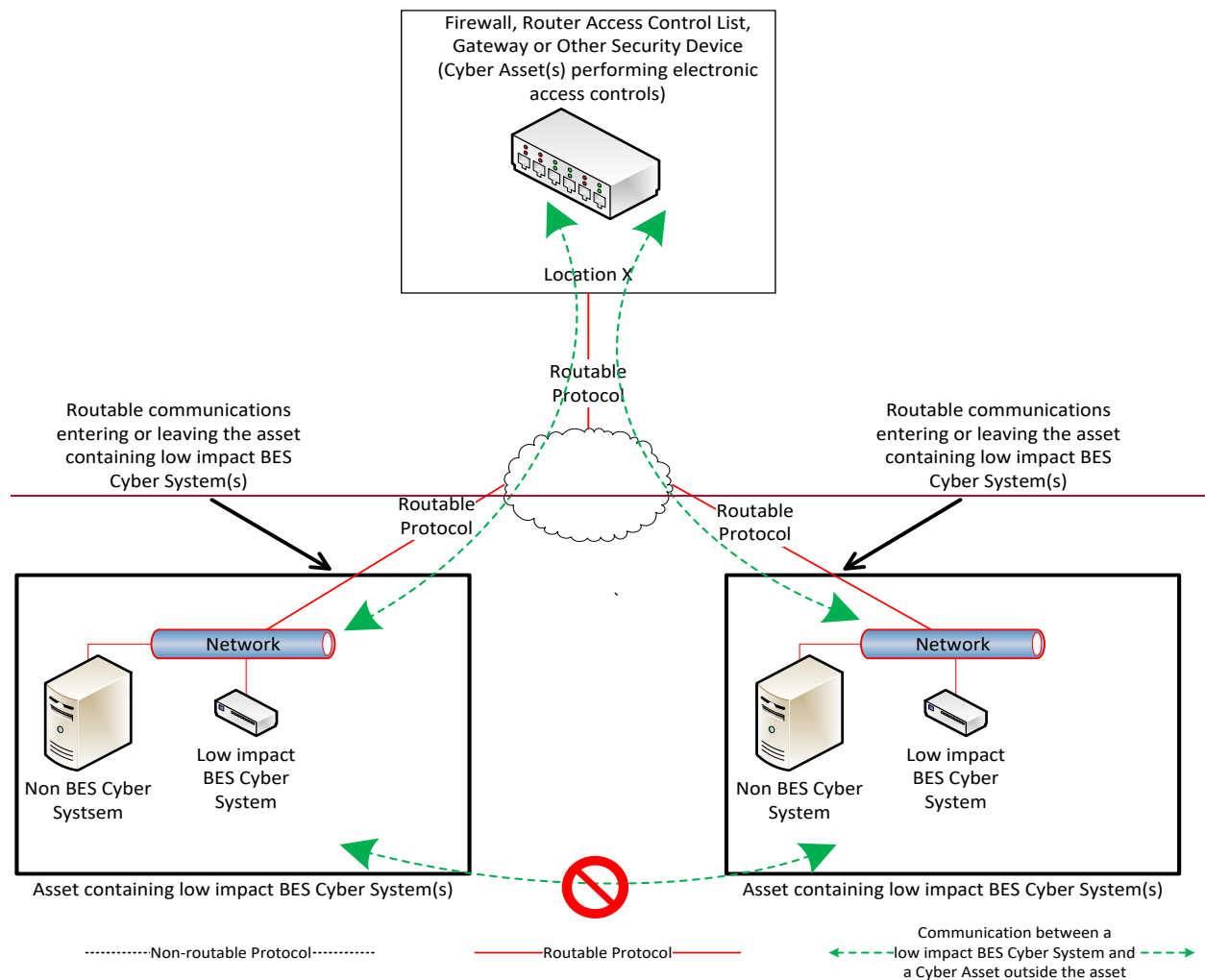
Reference Model 2—Network-based Inbound & Outbound Access Permissions

The Responsible Entity may choose to use a security device that permits only necessary inbound and outbound electronic access to the low impact BES Cyber System(s) within the asset containing the low impact BES Cyber System(s). In this example, two low impact BES Cyber Systems are accessed using the routable protocol that is entering or leaving the asset containing the low impact BES Cyber System(s). The IP/Serial converter is continuing the same communications session from the Cyber Asset(s) that are outside the asset to the low impact BES Cyber System(s). The security device provides the electronic access controls to permit only necessary inbound and outbound routable protocol access to the low impact BES Cyber System(s). When permitting the inbound and outbound electronic access permissions using access control lists, the Responsible Entity could restrict communication(s) using source and destination addresses or ranges of addresses. Responsible Entities could also restrict communication(s) using ports or services based on the capability of the electronic access control, the low impact BES Cyber System(s), or the application(s).



Reference Model 3—Centralized Network-based Inbound & Outbound Access Permissions

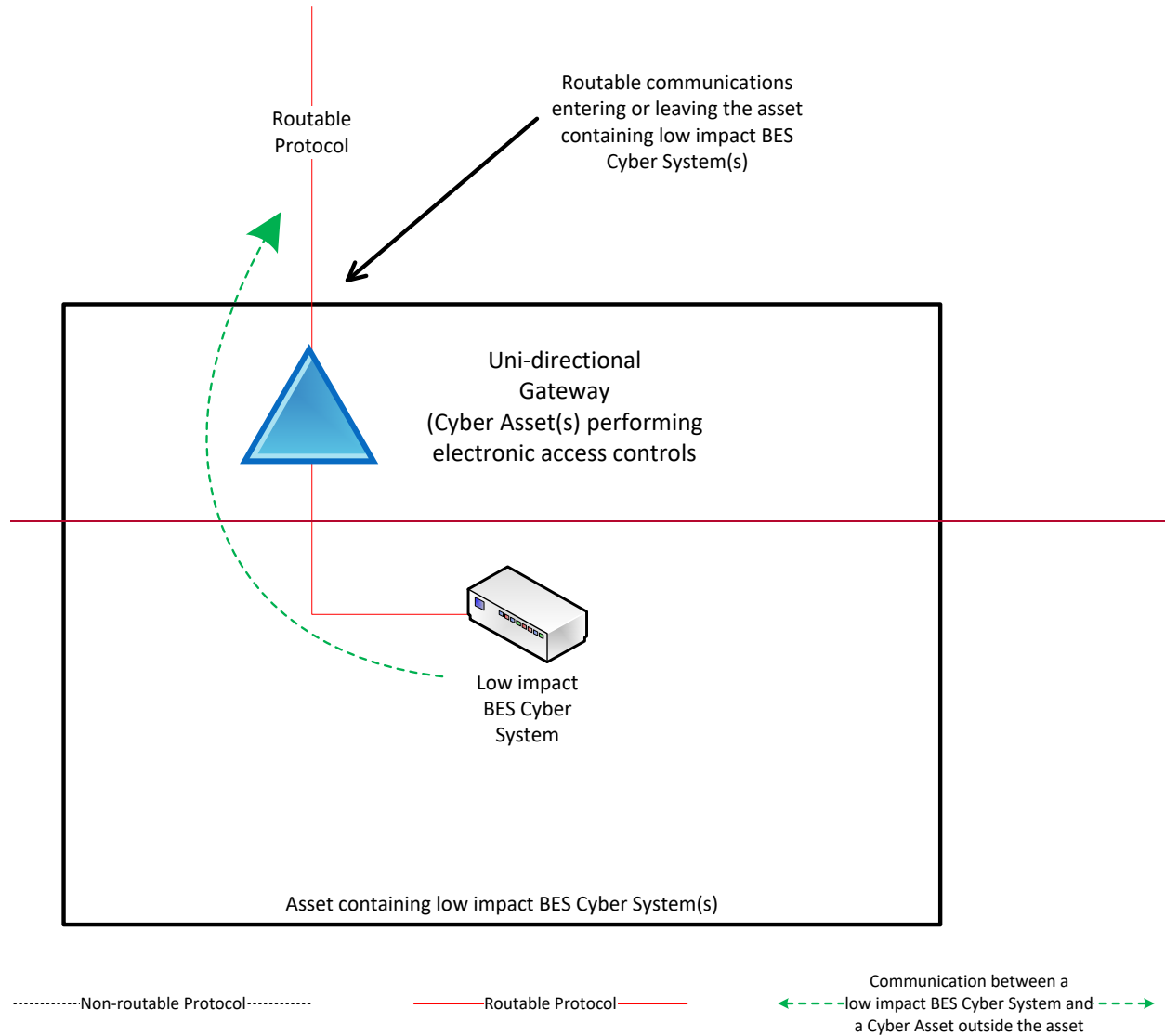
The Responsible Entity may choose to utilize a security device at a centralized location that may or may not be at another asset containing low impact BES Cyber System(s). The electronic access control(s) do not necessarily have to reside inside the asset containing the low impact BES Cyber System(s). A security device is in place at "Location X" to act as the electronic access control and permit only necessary inbound and outbound routable protocol access between the low impact BES Cyber System(s) and the Cyber Asset(s) outside each asset containing low impact BES Cyber System(s). Care should be taken that electronic access to or between each asset is through the Cyber Asset(s) determined by the Responsible Entity to be performing electronic access controls at the centralized location. When permitting the inbound and outbound electronic access permissions using access control lists, the Responsible Entity could restrict communication(s) using source and destination addresses or ranges of addresses. Responsible Entities could also restrict communication(s) using ports or services based on the capability of the electronic access control, the low impact BES Cyber System(s), or the application(s).



Reference Model 3

Reference Model 4—Uni-directional Gateway

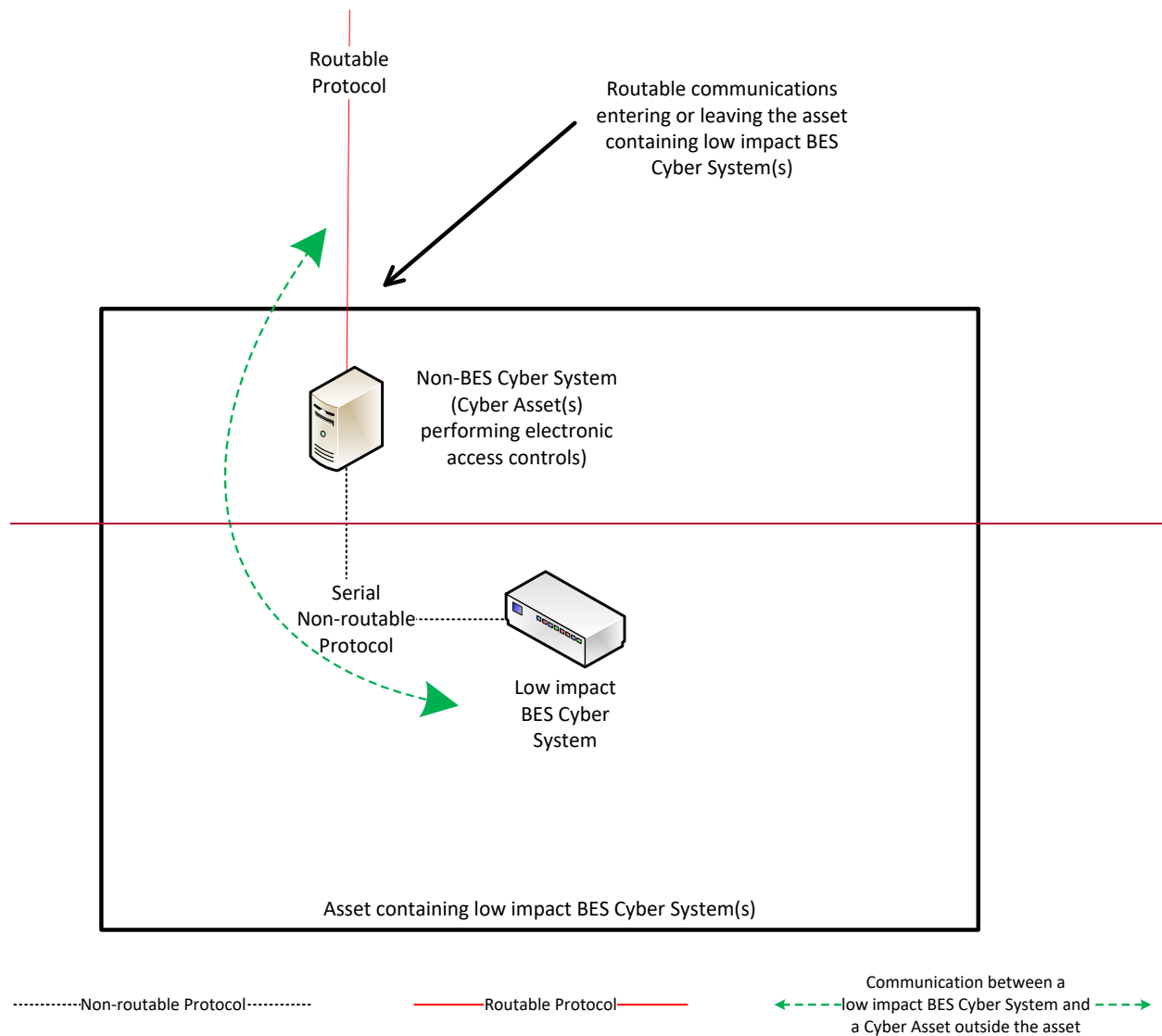
The Responsible Entity may choose to utilize a uni-directional gateway as the electronic access control. The low impact BES Cyber System(s) is not accessible (data cannot flow into the low impact BES Cyber System) using the routable protocol entering the asset due to the implementation of a “one-way” (uni-directional) path for data to flow. The uni-directional gateway is configured to permit only the necessary outbound communications using the routable protocol communication leaving the asset.



Reference Model 4

Reference Model 5—User Authentication

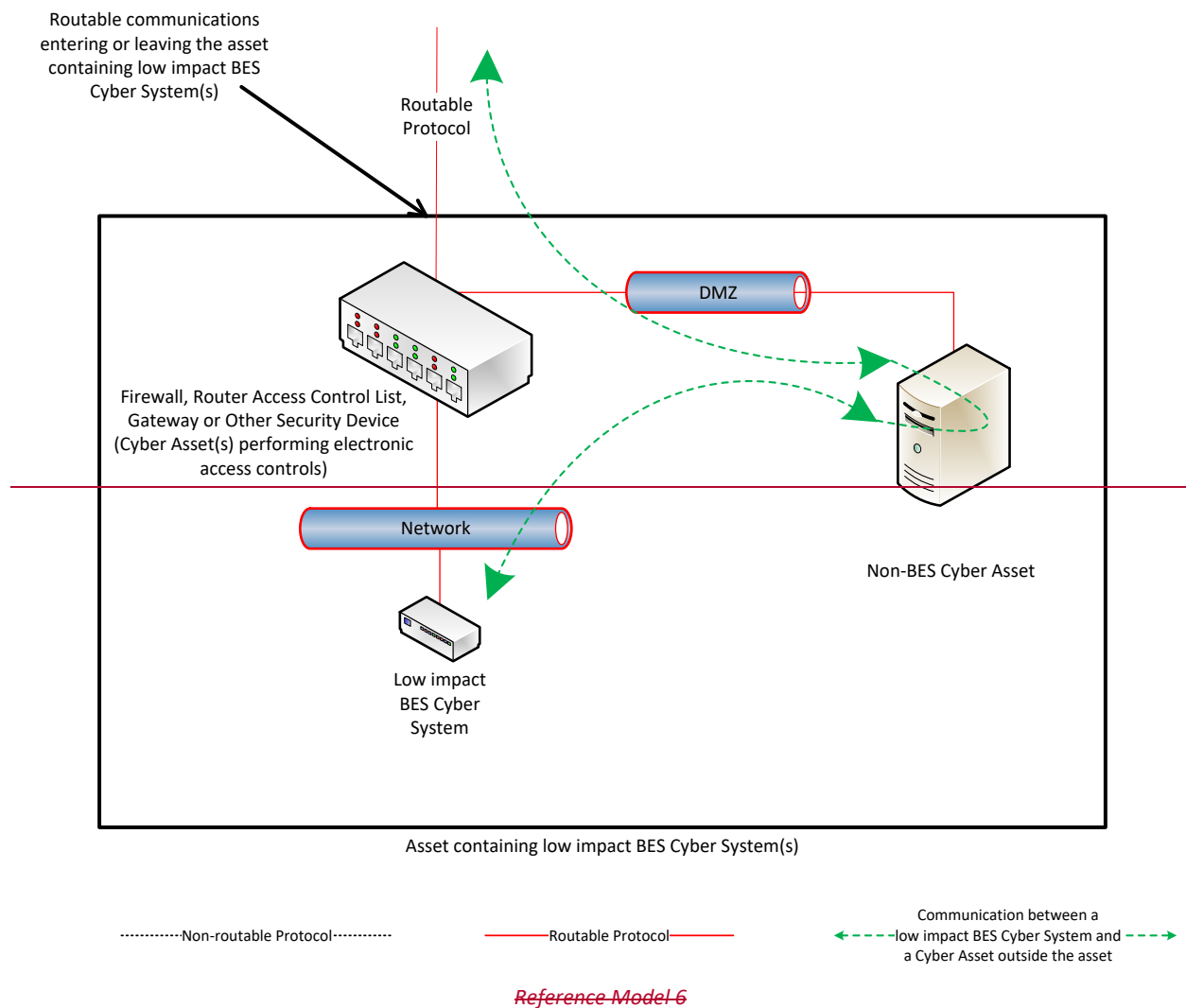
This reference model demonstrates that Responsible Entities have flexibility in choosing electronic access controls so long as the security objective of the requirement is met. The Responsible Entity may choose to utilize a non-BES Cyber Asset located at the asset containing the low impact BES Cyber System that requires authentication for communication from the Cyber Asset(s) outside the asset. This non-BES Cyber System performing the authentication permits only authenticated communication to connect to the low impact BES Cyber System(s), meeting the first half of the security objective to permit only necessary inbound electronic access. Additionally, the non-BES Cyber System performing authentication is configured such that it permits only necessary outbound communication meeting the second half of the security objective. Often, the outbound communications would be controlled in this network architecture by permitting no communication to be initiated from the low impact BES Cyber System. This configuration may be beneficial when the only communication to a device is for user initiated interactive access.



Reference Model 5

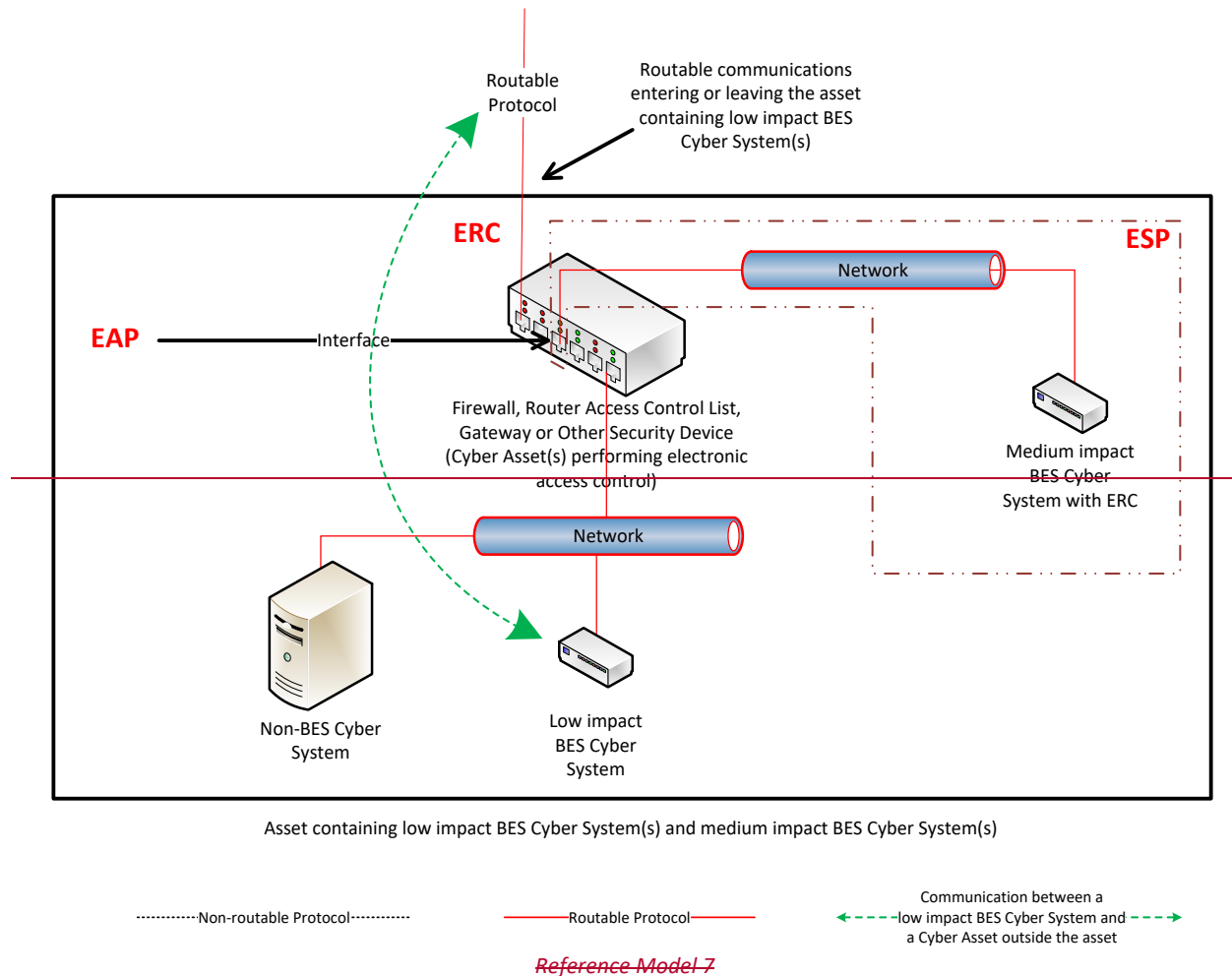
Reference Model 6—Indirect Access

In implementing its electronic access controls, the Responsible Entity may identify that it has indirect access between the low impact BES Cyber System and a Cyber Asset outside the asset containing the low impact BES Cyber System through a non-BES Cyber Asset located within the asset. This indirect access meets the criteria of having communication between the low impact BES Cyber System and a Cyber Asset outside the asset containing the low impact BES Cyber System. In this reference model, it is intended that the Responsible Entity implement electronic access controls that permit only necessary inbound and outbound electronic access to the low impact BES Cyber System. Consistent with the other reference models provided, the electronic access in this reference model is controlled using the security device that is restricting the communication that is entering or leaving the asset.



Reference Model 7—Electronic Access Controls at assets containing low impact BES Cyber Systems and ERC

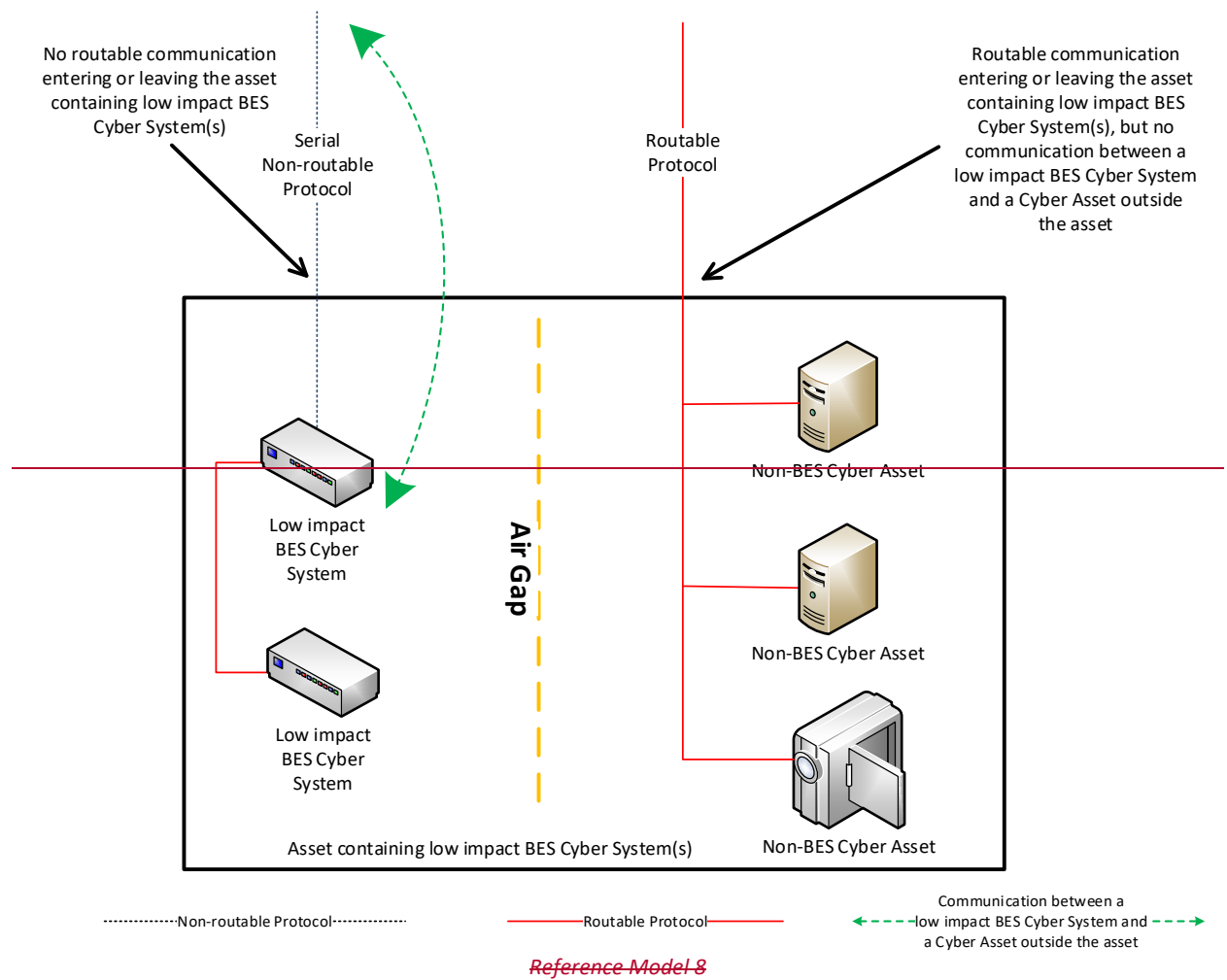
In this reference model, there is both a routable protocol entering and leaving the asset containing the low impact BES Cyber System(s) that is used by Cyber Asset(s) outside the asset and External Routable Connectivity because there is at least one medium impact BES Cyber System and one low impact BES Cyber System within the asset using the routable protocol communications. The Responsible Entity may choose to leverage an interface on the medium impact Electronic Access Control or Monitoring Systems (EACMS) to provide electronic access controls for purposes of CIP-003. The EACMS is therefore performing multiple functions—as a medium impact EACMS and as implementing electronic access controls for an asset containing low impact BES Cyber Systems.



~~Reference Model 8—Physical Isolation and Serial Non-routable Communications— No Electronic Access Controls Required~~

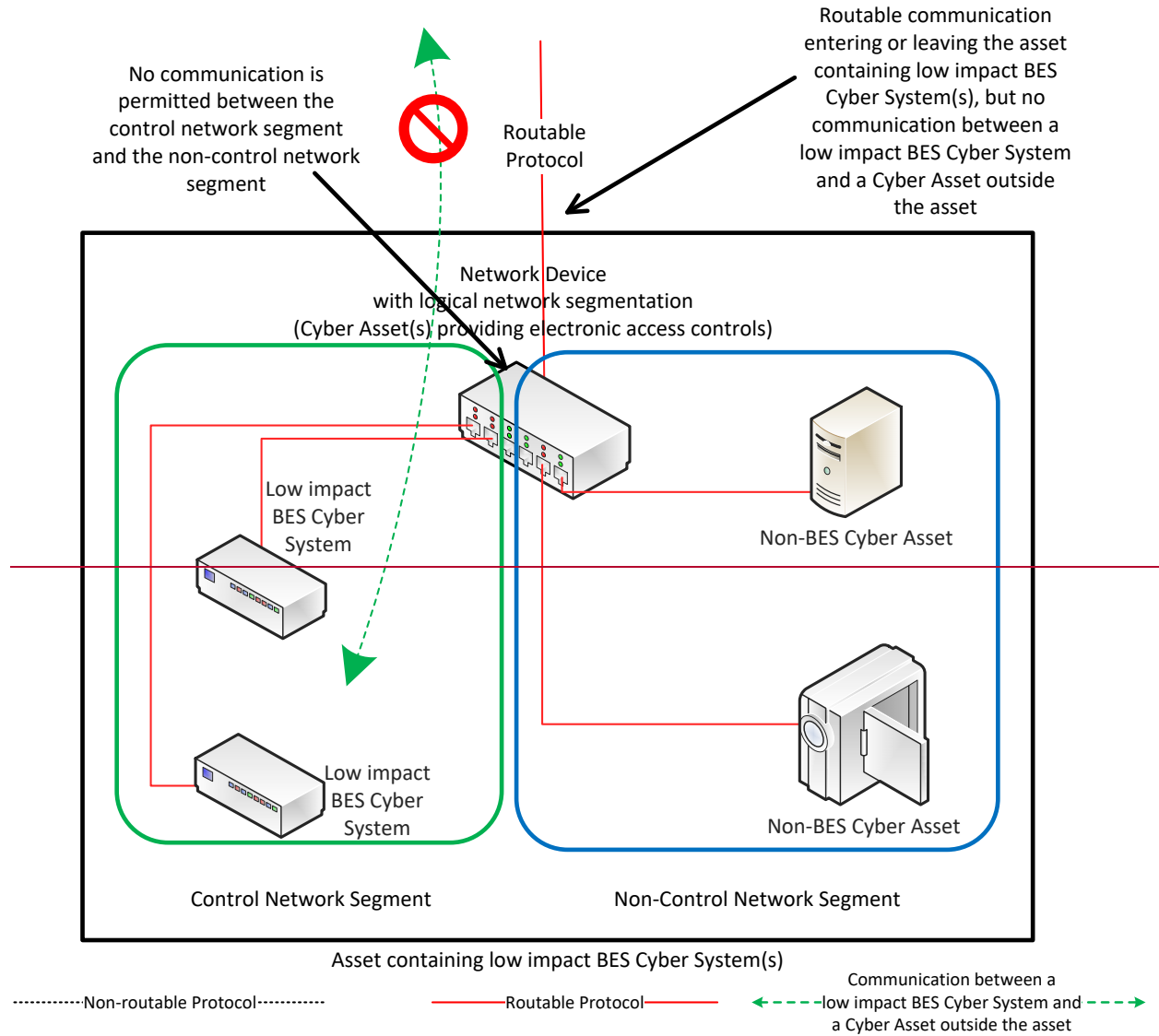
~~In this reference model, the criteria from Attachment 1, Section 3.1 requiring the implementation of electronic access controls are not met. This reference model demonstrates three concepts:~~

- ~~1) The physical isolation of the low impact BES Cyber System(s) from the routable protocol communication entering or leaving the asset containing the low impact BES Cyber System(s), commonly referred to as an 'air gap', mitigates the need to implement the required electronic access controls;~~
- ~~2) The communication to the low impact BES Cyber System from a Cyber Asset outside the asset containing the low impact BES Cyber System(s) using only a serial non-routable protocol where such communication is entering or leaving the asset mitigates the need to implement the required electronic access controls.~~
- ~~3) The routable protocol communication between the low impact BES Cyber System(s) and other Cyber Asset(s), such as the second low impact BES Cyber System depicted, may exist without needing to implement the required electronic access controls so long as the routable protocol communications never leaves the asset containing the low impact BES Cyber System(s).~~



Reference Model 9—Logical Isolation—No Electronic Access Controls Required

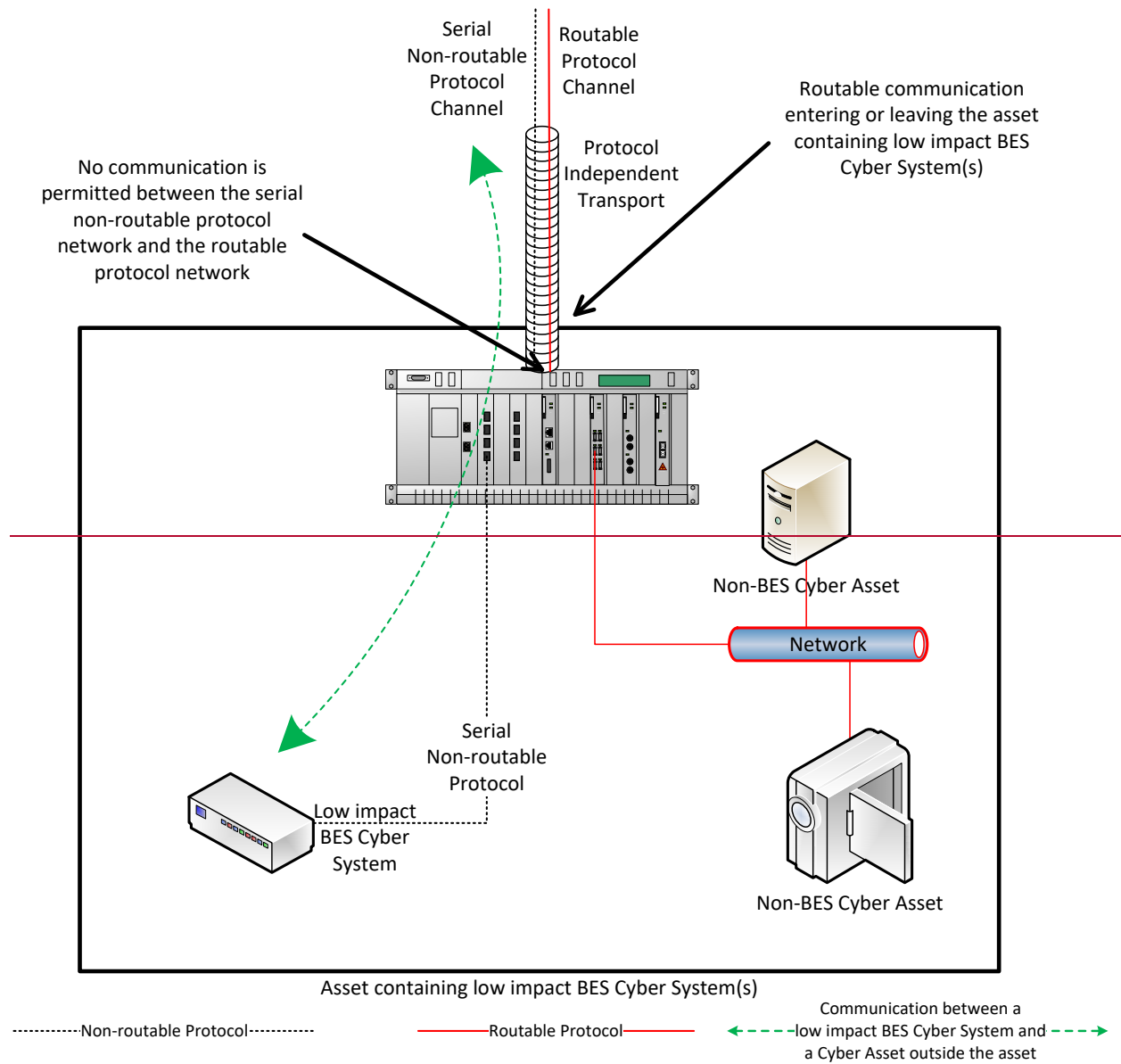
In this reference model, the criteria from Attachment 1, Section 3.1 requiring the implementation of electronic access controls are not met. The Responsible Entity has logically isolated the low impact BES Cyber System(s) from the routable protocol communication entering or leaving the asset containing low impact BES Cyber System(s). The logical network segmentation in this reference model permits no communication between a low impact BES Cyber System and a Cyber Asset outside the asset. Additionally, no indirect access exists because those non-BES Cyber Assets that are able to communicate outside the asset are strictly prohibited from communicating to the low impact BES Cyber System(s). The low impact BES Cyber System(s) is on an isolated network segment with logical controls preventing routable protocol communication into or out of the network containing the low impact BES Cyber System(s) and these communications never leave the asset using a routable protocol.



Reference Model 9

~~Reference Model 10—Serial Non-routable Communications Traversing an Isolated Channel on a Non-routable Transport Network—No Electronic Access Controls Required~~

~~In this reference model, the criteria from Attachment 1, Section 3.1 requiring the implementation of electronic access controls are not met. This reference model depicts communication between a low impact BES Cyber System and a Cyber Asset outside the asset containing the low impact BES Cyber System over a serial non-routable protocol which is transported across a wide-area network using a protocol independent transport that may carry routable and non-routable communication such as a Time-Division Multiplexing (TDM) network, a Synchronous Optical Network (SONET), or a Multiprotocol Label Switching (MPLS) network. While there is routable protocol communication entering or leaving the asset containing low impact BES Cyber Systems(s) and there is communication between a low impact BES Cyber System and a Cyber Asset outside the asset, the communication between the low impact BES Cyber System and the Cyber Asset outside the asset is not using the routable protocol communication. This model is related to Reference Model 9 in that it relies on logical isolation to prohibit the communication between a low impact BES Cyber System and a Cyber Asset outside the asset from using a routable protocol.~~



Reference Model 10

Dial-up Connectivity

Dial-up Connectivity to a low impact BES Cyber System is set to dial out only (no auto-answer) to a preprogrammed number to deliver data. Incoming Dial-up Connectivity is to a dialback modem, a modem that must be remotely controlled by the control center or control room, has some form of access control, or the low impact BES Cyber System has access control.

Insufficient Access Controls

Some examples of situations that would lack sufficient access controls to meet the intent of this requirement include:

- An asset has Dial-up Connectivity and a low impact BES Cyber System is reachable via an auto-answer modem that connects any caller to the Cyber Asset that has a default password. There is no practical access control in this instance.
- A low impact BES Cyber System has a wireless card on a public carrier that allows the BES Cyber System to be reachable via a public IP address. In essence, low impact BES Cyber Systems should not be accessible from the Internet and search engines such as Shodan.
- Dual-homing or multiple network interface cards without disabling IP forwarding in the non-BES Cyber Asset within the DMZ to provide separation between the low impact BES Cyber System(s) and the external network would not meet the intent of “controlling” inbound and outbound electronic access assuming there was no other host-based firewall or other security devices on the non-BES Cyber Asset.

Requirement R2, Attachment 1, Section 4—Cyber Security Incident Response

The entity should have one or more documented Cyber Security Incident response plan(s) that include each of the topics listed in Section 4. If, in the normal course of business, suspicious activities are noted at an asset containing low impact BES Cyber System(s), the intent is for the entity to implement a Cyber Security Incident response plan that will guide the entity in responding to the incident and reporting the incident if it rises to the level of a Reportable Cyber Security Incident.

Entities are provided the flexibility to develop their Attachment 1, Section 4 Cyber Security Incident response plan(s) by asset or group of assets. The plans do not need to be on a per asset site or per low impact BES Cyber System basis. Entities can choose to use a single enterprise-wide plan to fulfill the obligations for low impact BES Cyber Systems.

The plan(s) must be tested once every 36 months. This is not an exercise per low impact BES Cyber Asset or per type of BES Cyber Asset but rather is an exercise of each incident response plan the entity created to meet this requirement. An actual Reportable Cyber Security Incident counts as an exercise as do other forms of tabletop exercises or drills. NERC-led exercises such as GridEx participation would also count as an exercise provided the entity’s response plan is followed. The intent of the requirement is for entities to keep the Cyber Security Incident response plan(s) current, which includes updating the plan(s), if needed, within 180 days following a test or an actual incident.

For low impact BES Cyber Systems, the only portion of the definition of Cyber Security Incident that would apply is, “A malicious act or suspicious event that disrupts, or was an attempt to

~~disrupt, the operation of a BES Cyber System.” The other portion of that definition is not to be used to require ESPs and PSPs for low impact BES Cyber Systems.~~

~~Requirement R2, Attachment 1, Section 5—Transient Cyber Assets and Removable Media Malicious Code Risk Mitigation~~

~~Most BES Cyber Assets and BES Cyber Systems are isolated from external public or untrusted networks, and therefore Transient Cyber Assets and Removable Media are needed to transport files to and from secure areas to maintain, monitor, or troubleshoot critical systems. Transient Cyber Assets and Removable Media are a potential means for cyber attack. To protect the BES Cyber Assets and BES Cyber Systems, CIP-003 Requirement R2, Attachment 1, Section 5 requires Responsible Entities to document and implement a plan for how they will mitigate the risk of malicious code introduction to low impact BES Cyber Systems from Transient Cyber Assets and Removable Media. The approach of defining a plan allows the Responsible Entity to document processes that are supportable within its organization and in alignment with its change management processes.~~

~~Transient Cyber Assets can be one of many types of devices from a specially designed device for maintaining equipment in support of the BES to a platform such as a laptop, desktop, or tablet that may interface with or run applications that support BES Cyber Systems and is capable of transmitting executable code to the BES Cyber Asset(s) or BES Cyber System(s). Note: Cyber Assets connected to a BES Cyber System for less than 30 days due to an unplanned removal, such as premature failure, are not intended to be identified as Transient Cyber Assets. Removable Media subject to this requirement include, among others, floppy disks, compact disks, USB flash drives, external hard drives, and other flash memory cards/drives that contain nonvolatile memory.~~

~~Examples of these temporarily connected devices include, but are not limited to:~~

- ~~• Diagnostic test equipment;~~
- ~~• Equipment used for BES Cyber System maintenance; or~~
- ~~• Equipment used for BES Cyber System configuration.~~

~~To meet the objective of mitigating risks associated with the introduction of malicious code at low impact BES Cyber Systems, Section 5 specifies the capabilities and possible security methods available to Responsible Entities based upon asset type and ownership.~~

~~With the list of options provided in Attachment 1, the entity has the discretion to use the option(s) that is most appropriate. This includes documenting its approach for how and when the entity reviews the Transient Cyber Asset under its control or under the control of parties other than the Responsible Entity. The entity should avoid implementing a security function that jeopardizes reliability by taking actions that would negatively impact the performance or support of the Transient Cyber Asset or BES Cyber Asset.~~

Malicious Code Risk Mitigation

The terms “mitigate”, “mitigating”, and “mitigation” are used in Section 5 in Attachment 1 to address the risks posed by malicious code when connecting Transient Cyber Assets and Removable Media to BES Cyber Systems. Mitigation is intended to mean that entities reduce security risks presented by connecting the Transient Cyber Asset or Removable Media. When determining the method(s) to mitigate the introduction of malicious code, it is not intended for entities to perform and document a formal risk assessment associated with the introduction of malicious code.

Per Transient Cyber Asset Capability

As with other CIP standards, the requirements are intended for an entity to use the method(s) that the system is capable of performing. The use of “per Transient Cyber Asset capability” is to eliminate the need for a Technical Feasibility Exception when it is understood that the device cannot use a method(s). For example, for malicious code, many types of appliances are not capable of implementing antivirus software; therefore, because it is not a capability of those types of devices, implementation of the antivirus software would not be required for those devices.

Requirement R2, Attachment 1, Section 5.1—Transient Cyber Asset(s) Managed by the Responsible Entity

For Transient Cyber Assets and Removable Media that are connected to both low impact and medium/high impact BES Cyber Systems, entities must be aware of the differing levels of requirements and manage these assets under the program that matches the highest impact level to which they will connect.

Section 5.1: Entities are to document and implement their plan(s) to mitigate malicious code through the use of one or more of the protective measures listed, based on the capability of the Transient Cyber Asset.

The Responsible Entity has the flexibility to apply the selected method(s) to meet the objective of mitigating the introductions of malicious code either in an on-going or in an on-demand manner. An example of managing a device in an on-going manner is having the antivirus solution for the device managed as part of an end-point security solution with current signature or pattern updates, regularly scheduled systems scans, etc. In contrast, for devices that are used infrequently and the signatures or patterns are not kept current, the entity may manage those devices in an on-demand manner by requiring an update to the signatures or patterns and a scan of the device before the device is connected to ensure that it is free of malicious code.

Selecting management in an on-going or on-demand manner is not intended to imply that the control has to be verified at every single connection. For example, if the device is managed in an on-demand manner, but will be used to perform maintenance on several BES Cyber Asset(s), the Responsible Entity may choose to document that the Transient Cyber Asset has been updated before being connected as a Transient Cyber Asset for the first use of that maintenance work. The intent is not to require a log documenting each connection of a Transient Cyber Asset to a BES Cyber Asset.

The following is additional discussion of the methods to mitigate the introduction of malicious code.

- Antivirus software, including manual or managed updates of signatures or patterns, provides flexibility to manage Transient Cyber Asset(s) by deploying antivirus or endpoint security tools that maintain a scheduled update of the signatures or patterns. Also, for devices that do not regularly connect to receive scheduled updates, entities may choose to update the signatures or patterns and scan the Transient Cyber Asset prior to connection to ensure no malicious software is present.
- Application whitelisting is a method of authorizing only the applications and processes that are necessary on the Transient Cyber Asset. This reduces the risk that malicious software could execute on the Transient Cyber Asset and impact the BES Cyber Asset or BES Cyber System.
- When using methods other than those listed, entities need to document how the other method(s) meet the objective of mitigating the risk of the introduction of malicious code.

If malicious code is discovered on the Transient Cyber Asset, it must be mitigated prior to connection to a BES Cyber System to prevent the malicious code from being introduced into the BES Cyber System. An entity may choose to not connect the Transient Cyber Asset to a BES Cyber System to prevent the malicious code from being introduced into the BES Cyber System. Entities should also consider whether the detected malicious code is a Cyber Security Incident.

Requirement R2, Attachment 1, Section 5.2—Transient Cyber Asset(s) Managed by a Party Other than the Responsible Entity

Section 5 also recognizes the lack of direct control over Transient Cyber Assets that are managed by parties other than the Responsible Entity. This lack of control, however, does not obviate the Responsible Entity's responsibility to ensure that methods have been deployed to mitigate the introduction of malicious code to low impact BES Cyber System(s) from Transient Cyber Assets it does not manage. Section 5 requires entities to review the other party's security practices with respect to Transient Cyber Assets to help meet the objective of the requirement. The use of "prior to connecting the Transient Cyber Assets" is intended to ensure that the Responsible Entity conducts the review before the first connection of the Transient Cyber Asset to help meet the objective to mitigate the introduction of malicious code. The SDT does not intend for the Responsible Entity to conduct a review for every single connection of that Transient Cyber Asset once the Responsible Entity has established the Transient Cyber Asset is meeting the security objective. The intent is to not require a log documenting each connection of a Transient Cyber Asset to a BES Cyber Asset.

To facilitate these controls, Responsible Entities may execute agreements with other parties to provide support services to BES Cyber Systems and BES Cyber Assets that may involve the use of Transient Cyber Assets. Entities may consider using the Department of Energy Cybersecurity

~~Procurement Language for Energy Delivery dated April 2014.⁴ Procurement language may unify the other party and entity actions supporting the BES Cyber Systems and BES Cyber Assets. CIP program attributes may be considered including roles and responsibilities, access controls, monitoring, logging, vulnerability, and patch management along with incident response and back-up recovery may be part of the other party's support. Entities may consider the "General Cybersecurity Procurement Language" and "The Supplier's Life Cycle Security Program" when drafting Master Service Agreements, Contracts, and the CIP program processes and controls.~~

Section 5.2.1: ~~Entities are to document and implement their process(es) to mitigate the introduction of malicious code through the use of one or more of the protective measures listed.~~

- ~~• Review the use of antivirus software and signature or pattern levels to ensure that the level is adequate to the Responsible Entity to mitigate the risk of malicious software being introduced to an applicable system.~~
- ~~• Review the antivirus or endpoint security processes of the other party to ensure that their processes are adequate to the Responsible Entity to mitigate the risk of introducing malicious software to an applicable system.~~
- ~~• Review the use of application whitelisting used by the other party to mitigate the risk of introducing malicious software to an applicable system.~~
- ~~• Review the use of live operating systems or software executable only from read-only media to ensure that the media is free from malicious software itself. Entities should review the processes to build the read-only media as well as the media itself.~~
- ~~• Review system hardening practices used by the other party to ensure that unnecessary ports, services, applications, etc. have been disabled or removed. This method intends to reduce the attack surface on the Transient Cyber Asset and reduce the avenues by which malicious software could be introduced.~~

Section 5.2.2: ~~The intent of this section is to ensure that after conducting the selected review from Section 5.2.1, if there are deficiencies identified, actions mitigating the risk of the introduction of malicious code to low impact BES Cyber Systems must be completed prior to connecting the device(s) to an applicable system.~~

Requirement R2, Attachment 1, Section 5.3—Removable Media

~~Entities have a high level of control for Removable Media that are going to be connected to their BES Cyber Assets.~~

Section 5.3: ~~Entities are to document and implement their process(es) to mitigate the introduction of malicious code through the use of one or more method(s) to detect malicious~~

⁴ <http://www.energy.gov/oe/downloads/cybersecurity-procurement-language-energy-delivery-april-2014>

~~code on the Removable Media before it is connected to a BES Cyber Asset. When using the method(s) to detect malicious code, it is expected to occur from a system that is not part of the BES Cyber System to reduce the risk of propagating malicious code into the BES Cyber System network or onto one of the BES Cyber Assets. If malicious code is discovered, it must be removed or mitigated to prevent it from being introduced into the BES Cyber Asset or BES Cyber System. Entities should also consider whether the detected malicious code is a Cyber Security Incident. Frequency and timing of the methods used to detect malicious code were intentionally excluded from the requirement because there are multiple timing scenarios that can be incorporated into a plan to mitigate the risk of malicious code. The SDT does not intend to obligate a Responsible Entity to conduct a review for every single connection of Removable Media, but rather to implement its plan(s) in a manner that protects all BES Cyber Systems where Removable Media may be used. The intent is to not require a log documenting each connection of Removable Media to a BES Cyber Asset.~~

~~As a method to detect malicious code, entities may choose to use Removable Media with on-board malicious code detection tools. For these tools, the Removable Media are still used in conjunction with a Cyber Asset to perform the detection. For Section 5.3.1, the Cyber Asset used to perform the malicious code detection must be outside of the BES Cyber System.~~

Requirement R3:

~~The intent of CIP-003-8, Requirement R3 is effectively unchanged since prior versions of the standard. The specific description of the CIP Senior Manager has now been included as a defined term rather than clarified in the Reliability Standard itself to prevent any unnecessary cross-reference to this standard. It is expected that the CIP Senior Manager will play a key role in ensuring proper strategic planning, executive/board-level awareness, and overall program governance.~~

Requirement R4:

~~As indicated in the rationale for CIP-003-8, Requirement R4, this requirement is intended to demonstrate a clear line of authority and ownership for security matters. The intent of the SDT was not to impose any particular organizational structure, but, rather, the intent is to afford the Responsible Entity significant flexibility to adapt this requirement to its existing organizational structure. A Responsible Entity may satisfy this requirement through a single delegation document or through multiple delegation documents. The Responsible Entity can make use of the delegation of the delegation authority itself to increase the flexibility in how this applies to its organization. In such a case, delegations may exist in numerous documentation records as long as the collection of these documentation records shows a clear line of authority back to the CIP Senior Manager. In addition, the CIP Senior Manager could also choose not to delegate any authority and meet this requirement without such delegation documentation.~~

~~The Responsible Entity must keep its documentation of the CIP Senior Manager and any delegations up to date. This is to ensure that individuals do not assume any undocumented authority. However, delegations do not have to be re-instated if the individual who delegated the task changes roles or the individual is replaced. For instance, assume that John Doe is named the CIP Senior Manager and he delegates a specific task to the Substation Maintenance~~

~~Manager. If John Doe is replaced as the CIP Senior Manager, the CIP Senior Manager documentation must be updated within the specified timeframe, but the existing delegation to the Substation Maintenance Manager remains in effect as approved by the previous CIP Senior Manager, John Doe.~~

Rationale:

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

Rationale for Requirement R1:

~~One or more security policies enable effective implementation of the requirements of the cyber security Reliability Standards. The purpose of policies is to provide a management and governance foundation for all requirements that apply to a Responsible Entity's BES Cyber Systems. The Responsible Entity can demonstrate through its policies that its management supports the accountability and responsibility necessary for effective implementation of the requirements.~~

~~Annual review and approval of the cyber security policies ensures that the policies are kept up-to-date and periodically reaffirms management's commitment to the protection of its BES Cyber Systems.~~

Rationale for Requirement R2:

~~In response to FERC Order No. 791, Requirement R2 requires entities to develop and implement cyber security plans to meet specific security control objectives for assets containing low impact BES Cyber System(s). The cyber security plan(s) covers five subject matter areas: (1) cyber security awareness; (2) physical security controls; (3) electronic access controls; (4) Cyber Security Incident response; and (5) Transient Cyber Asset and Removable Media Malicious Code Risk Mitigation. This plan(s), along with the cyber security policies required under Requirement R1, Part 1.2, provides a framework for operational, procedural, and technical safeguards for low impact BES Cyber Systems.~~

~~Considering the varied types of low impact BES Cyber Systems across the BES, Attachment 1 provides Responsible Entities flexibility on how to apply the security controls to meet the security objectives. Additionally, because many Responsible Entities have multiple impact rated BES Cyber Systems, nothing in the requirement prohibits entities from using their high and medium impact BES Cyber System policies, procedures, and processes to implement security controls required for low impact BES Cyber Systems, as detailed in Requirement R2, Attachment 1.~~

~~Responsible Entities will use their identified assets containing low impact BES Cyber System(s) (developed pursuant to CIP-002) to substantiate the sites or locations associated with low impact BES Cyber System(s). However, there is no requirement or compliance expectation for Responsible Entities to maintain a list(s) of individual low impact BES Cyber System(s) and their associated cyber assets or to maintain a list of authorized users.~~

Rationale for Modifications to Sections 2 and 3 of Attachment 1 (Requirement R2):

~~Requirement R2 mandates that entities develop and implement one or more cyber security plan(s) to meet specific security objectives for assets containing low impact BES Cyber System(s). In Paragraph 73 of FERC Order No. 822, the Commission directed NERC to modify "...the Low Impact External Routable Connectivity definition to reflect the commentary in the Guidelines and Technical Basis section of CIP-003-6..." to provide needed clarity to the definition~~

~~and eliminate ambiguity surrounding the term ‘direct’ as it is used in the proposed definition...within one year of the effective date of this Final Rule.”~~

~~The revisions to Section 3 incorporate select language from the LERC definition into Attachment 1 and focus the requirement on implementing electronic access controls for asset(s) containing low impact BES Cyber System(s). This change requires the Responsible Entity to permit only necessary inbound and outbound electronic access when using a routable protocol entering or leaving the asset between low impact BES Cyber System(s) and a Cyber Asset(s) outside the asset containing low impact BES Cyber system(s). When this communication is present, Responsible Entities are required to implement electronic access controls unless that communication meets the following exclusion language (previously in the definition of LERC) contained in romanette (iii): “not used for time sensitive protection or control functions between intelligent electronic devices (e.g. communications using protocol IEC TR-61850-90-5 R-GOOSE)”.~~

~~The revisions to Section 2 of Attachment 1 complement the revisions to Section 3; consequently, the requirement now mandates the Responsible Entity control physical access to “the Cyber Asset(s), as specified by the Responsible Entity, that provide electronic access control(s) implemented for Section 3.1, if any.” The focus on electronic access controls rather than on the Low Impact BES Cyber System Electronic Access Points (LEAPs) eliminates the need for LEAPs.~~

~~Given these revisions to Sections 2 and 3, the NERC Glossary terms: Low Impact External Routable Connectivity (LERC) and Low Impact BES Cyber System Electronic Access Point (LEAP) will be retired.~~

~~Rationale for Section 5 of Attachment 1 (Requirement R2):~~

~~Requirement R2 mandates that entities develop and implement one or more cyber security plan(s) to meet specific security objectives for assets containing low impact BES Cyber System(s). In Paragraph 32 of FERC Order No. 822, the Commission directed NERC to “...provide mandatory protection for transient devices used at Low Impact BES Cyber Systems based on the risk posed to bulk electric system reliability.” Transient devices are potential vehicles for introducing malicious code into low impact BES Cyber Systems. Section 5 of Attachment 1 is intended to mitigate the risk of malware propagation to the BES through low impact BES Cyber Systems by requiring entities to develop and implement one or more plan(s) to address the risk. The cyber security plan(s) along with the cyber security policies required under Requirement R1, Part 1.2, provide a framework for operational, procedural, and technical safeguards for low impact BES Cyber Systems.~~

~~Rationale for Requirement R3:~~

~~The identification and documentation of the single CIP Senior Manager ensures that there is clear authority and ownership for the CIP program within an organization, as called for in Blackout Report Recommendation 43. The language that identifies CIP Senior Manager responsibilities is included in the Glossary of Terms used in NERC Reliability Standards so that it may be used across the body of CIP standards without an explicit cross-reference.~~

~~FERC Order No. 706, Paragraph 296, requests consideration of whether the single senior manager should be a corporate officer or equivalent. As implicated through the defined term, the senior manager has “the overall authority and responsibility for leading and managing implementation of the requirements within this set of standards” which ensures that the senior manager is of sufficient position in the Responsible Entity to ensure that cyber security receives the prominence that is necessary. In addition, given the range of business models for responsible entities, from municipal, cooperative, federal agencies, investor owned utilities, privately owned utilities, and everything in between, the SDT believes that requiring the CIP Senior Manager to be a “corporate officer or equivalent” would be extremely difficult to interpret and enforce on a consistent basis.~~

~~Rationale for Requirement R4:~~

~~The intent of the requirement is to ensure clear accountability within an organization for certain security matters. It also ensures that delegations are kept up to date and that individuals do not assume undocumented authority.~~

~~In FERC Order No. 706, Paragraphs 379 and 381, the Commission notes that Recommendation 43 of the 2003 Blackout Report calls for “clear lines of authority and ownership for security matters.” With this in mind, the Standard Drafting Team has sought to provide clarity in the requirement for delegations so that this line of authority is clear and apparent from the documented delegations.~~

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 initial~~ an additional 45-day formal comment period with ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	03/18/20
SAR posted for comment	04/08/20
45-day formal comment period with ballot	~~04/26/21~~ <u>April 26 – June 9, 2021</u>

Anticipated Actions	Date
45-day formal comment period with ballot	November 2021
45-day formal comment period with ballot	March 2021
10-day final ballot	June 2021
Board adoption	August 2021

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None

A. Introduction

1. **Title:** Cyber Security – Communications between Control Centers
2. **Number:** CIP-012-2
3. **Purpose:** To protect the confidentiality, availability and integrity of Real-time Assessment and Real-time monitoring data transmitted between Control Centers.
4. **Applicability:**
 - 4.1. **Functional Entities:** The requirements in this standard apply to the following functional entities, referred to as “Responsible Entities,” that own or operate a Control Center.
 - 4.1.1. **Balancing Authority**
 - 4.1.2. **Generator Operator**
 - 4.1.3. **Generator Owner**
 - 4.1.4. **Reliability Coordinator**
 - 4.1.5. **Transmission Operator**
 - 4.1.6. **Transmission Owner**
 - 4.2. **Exemptions:** The following are exempt from Reliability Standard CIP-012-2:
 - 4.2.1. Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.
 - 4.2.2. 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. A Control Center that transmits to another Control Center Real-time Assessment or Real-time monitoring data pertaining only to the generation resource or Transmission station or substation co-located with the transmitting Control Center.
5. **Effective Date:** See Implementation Plan for CIP-012-2.

B. Requirements and Measures

- R1. The Responsible Entity shall implement, except under CIP Exceptional Circumstances, one or more documented plan(s) to mitigate the risks posed by unauthorized disclosure-~~and~~, unauthorized modification, and loss of availability of data used for Real-time Assessment and Real-time monitoring ~~data~~ while such data is being transmitted between any applicable Control Centers. The Responsible Entity is not required to include oral communications in its plan. The plan shall include: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

- 1.1. Identification of security and availability protection(s) used to mitigate the risks posed by unauthorized disclosure ~~and~~, unauthorized modification, and loss of availability of data used for Real-time Assessment and Real-time monitoring ~~data~~ while such data is being transmitted between Control Centers;
 - 1.2. Identification of ~~where the Responsible Entity applied security protection methods to be used for transmitting the recovery of communication links used to transmit~~ Real-time Assessment and Real-time monitoring data between Control Centers; ~~and;~~
 - 1.3. Identification of where the Responsible Entity applied security and availability protection(s) as required in Part 1.1; and
 - 1.3.1.4. If the Control Centers are owned or operated by different Responsible Entities, identification of the responsibilities of each Responsible Entity for applying security ~~protection~~ and availability protection(s) to the transmission of Real-time Assessment and Real-time monitoring data between those Control Centers.
- M1. Evidence may include, but is not limited to, documented plan(s) that meet the security mitigation objective of Requirement R1 and documentation demonstrating the implementation of the plan(s).
- ~~R2. The Responsible Entity shall implement, except under CIP Exceptional Circumstances, one or more documented plan(s) to provide for the availability of communications links and data used for Real-time Assessment and Real-time monitoring while being transmitted between Control Centers. The Responsible Entity is not required to include oral communications in its plan. The plan shall include: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]~~
- ~~2.1. Identification of how the Responsible Entity has provided for the availability of communications links and data used for Real-time Assessment and Real-time monitoring while being transmitted between Control Centers;~~
 - ~~2.2. Identification of how the Responsible Entity has addressed communications and data flow restoration to maintain continuity of operations in the Responsible Entity's plan; and~~
 - ~~2.3. If the Control Centers are owned or operated by different Responsible Entities, identification of the responsibilities of each Responsible Entity for providing availability of communications links and data used for Real-time Assessment and Real-time monitoring while being transmitted between Control Centers.~~
- ~~M2. Evidence may include, but is not limited to, documented plan(s) that meet the security objective of Requirement R2 and documentation demonstrating the implementation of the plan(s).~~

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: “Compliance Enforcement Authority” (CEA) means NERC, 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 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.

- The Responsible Entities shall keep data or evidence of each Requirement in this Reliability 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 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 Responsible Entity documented its plan(s) but failed to include one of the applicable Parts of the plan as specified in Requirement R1.	The Responsible Entity documented its plan(s) but failed to include two of the applicable Parts of the plan as specified in Requirement R1.	The Responsible Entity failed to document plan(s) for Requirement R1; Or The Responsible Entity failed to implement <u>three or more</u> any Parts of its plan(s) for Requirement R1, except under CIP Exceptional Circumstances.
~~R2.~~	~~N/A~~	~~The Responsible Entity documented its plan(s) but failed to include one of the applicable Parts of the plan as specified in Requirement R2.~~	~~The Responsible Entity documented its plan(s) but failed to include two of the applicable Parts of the plan as specified in Requirement R2.~~	~~The Responsible Entity failed to document plan(s) for Requirement R2; Or The Responsible Entity failed to implement any Part of its plan(s) for Requirement R2, except under CIP Exceptional Circumstances.~~

D. Regional Variances

None.

E. Associated Documents

- Implementation Plan.
- Technical Rationale for CIP-012-2.

Version History

Version	Date	Action	Change Tracking
1		Respond to FERC Order No. 822	New
1	August 16, 2018	Adopted by NERC Board of Trustees	
1	January 23, 2020	FERC Order issued approving CIP-012-1. Docket No. RM18-20-000;	
2	TBD	Adopted by NERC Board of Trustees	

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

Initial posting of 45-day formal comment period with ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	9/24/2020
SAR posted for comment	11/12 – 12/12/2020

Anticipated Actions	Date
45-day formal or informal comment period with ballot	December 2021
45-day formal or informal comment period with additional ballot	March 2022
45-day formal or informal comment period with additional ballot	June 2022
10-day final ballot	August 2022
Board adoption	November 2022

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):

~~Text~~None

A. Introduction

1. **Title:** Facility Interconnection Requirements
2. **Number:** FAC-001-~~43~~
3. **Purpose:** To avoid adverse impacts on the reliability of the Bulk Electric System, Transmission Owners and applicable Generator Owners must document and make Facility interconnection requirements available so that entities seeking to interconnect will have the necessary information.
4. **Applicability:**
 - 4.1. **Functional Entities:**
 - 4.1.1. Transmission Owner
 - 4.1.2. Applicable Generator Owner
 - 4.1.2.1. Generator Owner with a fully executed Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system.
5. **Effective Date:** See Implementation Plan for Project 2020-05-FAC-001-3.

B. Requirements and Measures

- R1.** Each Transmission Owner shall document Facility interconnection requirements, update them as needed, and make them available upon request. Each Transmission Owner's Facility interconnection requirements shall address interconnection requirements for: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*
- 1.1.** generation Facilities;
 - 1.2.** transmission Facilities; and
 - 1.3.** end-user Facilities.
- M1.** Each Transmission Owner shall have evidence (such as dated, documented Facility interconnection requirements) that it met all requirements in Requirement R1.
- R2.** Each applicable Generator Owner shall document Facility interconnection requirements and make them available upon request within 45 calendar days of full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*
- M2.** Each applicable Generator Owner shall have evidence (such as dated, documented Facility interconnection requirements) that it met all requirements in Requirement R2.
- R3.** Each Transmission Owner shall address the following items in its Facility interconnection requirements: *[Violation Risk Factor: Lower] [Time Horizon: Long-Term Planning]*
- 3.1.** Procedures for coordinated studies and identifying the impacts on affected systems for of new interconnections, or ~~materially modified~~ existing interconnections seeking to make a qualified change as defined by the Planning Coordinator under Reliability Standard FAC-002-4 Requirement R6, and their impacts on affected system(s).
 - 3.2.** Procedures for notifying those responsible for the reliability of affected system(s) of new interconnections or ~~materially modified~~ existing interconnections seeking to make a qualified change.
 - 3.3.** Procedures for confirming with those responsible for the reliability of affected systems that new Facilities or ~~materially modified existing~~ -Facilities seeking to make a qualified change are within a Balancing Authority Area's metered boundaries.
- M3.** Each Transmission Owner shall have evidence (such as dated, documented Facility interconnection requirements addressing the procedures) that it met all requirements in Requirement R3.
- R4.** Each applicable Generator Owner shall address the following items in its Facility interconnection requirements: *[Violation Risk Factor: Lower] [Time Horizon: Long-Term Planning]*

- 4.1. Procedures for coordinated studies of new interconnections and their impacts on affected system(s).
 - 4.2. Procedures for notifying those responsible for the reliability of affected system(s) of new interconnections.
 - 4.3. Procedures for confirming with those responsible for the reliability of affected systems that new Facilities or ~~materially modified~~existing Facilities seeking to make a qualified change as defined by the Planning Coordinator under Reliability Standard FAC-002-4 Requirement R6 are within a Balancing Authority Area's metered boundaries.
- M4.** Each applicable Generator Owner shall have evidence (such as dated, documented Facility interconnection requirements addressing the procedures) that it met all requirements in Requirement R4.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: “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 responsible entities shall retain documentation as evidence for three years.
- If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and 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 #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	Long-term Planning	Lower	N/A	The Transmission Owner documented Facility interconnection requirements and updated them as needed, but failed to make them available upon request. OR The Transmission Owner documented Facility interconnection requirements and made them available upon request, but failed to update them as needed. OR The Transmission Owner documented Facility interconnection requirements,	The Transmission Owner documented Facility interconnection requirements, but failed to update them as needed and failed to make them available upon request. OR The Transmission Owner documented Facility interconnection requirements, updated them as needed, and made them available upon request, but failed to address interconnection requirements for two of the Facilities as	The Transmission Owner did not document Facility interconnection requirements.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				updated them as needed, and made them available upon request, but failed to address interconnection requirements for one of the Facilities as specified in R1, Parts 1.1, 1.2, or 1.3.	specified in R1, Parts 1.1, 1.2, or 1.3.	
R2.	Long-term Planning	Lower	The applicable Generator Owner failed to document Facility interconnection requirements and make them available upon request until more than 45 calendar days but less than or equal to 60 calendar days after full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third	The applicable Generator Owner failed to document Facility interconnection requirements and make them available upon request until more than 60 calendar days but less than or equal to 70 calendar days after full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third	The applicable Generator Owner failed to document Facility interconnection requirements and make them available upon request until more than 70 calendar days but less than or equal to 80 calendar days after full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third	The applicable Generator Owner failed to document Facility interconnection requirements and make them available upon request until more than 80 calendar days after full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system.	party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system.	party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system.	existing Facility that is used to interconnect to the Transmission system.
R3.	Long-term Planning	Lower	N/A	The Transmission Owner failed to address one part of Requirement R3 Part 3.1 through Part 3.3.	The Transmission Owner failed to address two parts of Requirement R3 Part 3.1 through Part 3.3.	The Transmission Owner failed to address ~~three parts of~~ Requirement R3 Part 3.1 through Part 3.3.
R4.	Long-term Planning	Lower	N/A	The Generator Owner failed to address one part of Requirement R4 Part 4.1 through Part 4.3.	The Generator Owner failed to address two parts of Requirement R4 Part 4.1 through Part 4.3.	The Generator Owner failed to address ~~three parts of~~ Requirement R4 Part 4.1 through Part 4.3.

D. Regional Variances

None.

E. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1		Added requirements for Generator Owner and brought overall standard format up to date.	Revision under Project 2010-07
1	February 9, 2012	Adopted by the Board of Trustees	
1	September 19, 2013	A FERC order was issued on September 19, 2013, approving FAC-001-1. This standard became enforceable on November 25, 2013 for Transmission Owners. For Generator Owners, the standard becomes enforceable on January 1, 2015.	
2		Revisions to implement the recommendations of the FAC Five-Year Review Team.	Revision under Project 2010-02
2	August 14, 2014	Adopted by the Board of Trustees	
2	November 6, 2014	FERC letter order issued approving FAC-001-2.	
3	February 11, 2016	Adopted by the Board of Trustees	Moved BAL-005-0.2b Requirement R1 into FAC-001-3 Requirements R3 and R4
3	September 20, 2017	FERC Order No. 836 issued approving FAC-001-3	
3	February 19, 2021	FERC letter Order issued approving FAC-001-3 Errata	
<u>4</u>	<u>TBD</u>	<u>Adopted by the Board of Trustees</u>	<u>Revisions under Project 2020-05</u>

Guidelines and Technical Basis

Entities should have documentation to support the technical rationale for determining whether an existing interconnection was “materially modified.” Recognizing that what constitutes a “material modification” will vary from entity to entity, the intent is for this determination to be based on engineering judgment.

Requirement R3:

Originally the Parts of R3, with the exception of the first two bullets, which were added by the Project 2010-02 drafting team, this list has been moved to the Guidelines and Technical Basis section to provide entities with the flexibility to determine the Facility interconnection requirements that are technically appropriate for their respective Facilities. Including them as Parts of R3 was deemed too prescriptive, as frequently some items in the list do not apply to all applicable entities—and some applicable entities will have requirements that are not included in this list.

Each Transmission Owner and applicable Generator Owner should consider the following items in the development of Facility interconnection requirements:

- Procedures for requesting a new Facility interconnection or material modification to an existing interconnection
- Data required to properly study the interconnection
- Voltage level and MW and MVAR capacity or demand at the point of interconnection
- Breaker duty and surge protection
- System protection and coordination
- Metering and telecommunications
- Grounding and safety issues
- Insulation and insulation coordination
- Voltage, Reactive Power (including specifications for minimum static and dynamic reactive power requirements), and power factor control
- Power quality impacts
- Equipment ratings
- Synchronizing of Facilities
- Maintenance coordination
- Operational issues (abnormal frequency and voltages)
- Inspection requirements for new or materially modified existing interconnections
- Communications and procedures during normal and emergency operating conditions

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 approval, the text from the rationale boxes will be moved to this section.

Rationale for Requirement R3.3: Consistent with the Functional Model, there cannot be an assumption that the entity owning the transmission will be the same entity providing the BA function. It is the responsibility of the party interconnecting to make appropriate arrangements with a Balancing Authority to ensure its Facilities are within the BA's metered boundaries, which also serves to facilitate the process of the coordination between the two entities that will be required under numerous other standards upon the start of operation. Under 3.3, the Transmission Owner is responsible for confirming that the party interconnecting has made appropriate provisions with a Balancing Authority to operate within its metered boundaries.

Rationale for Requirement R4.3: Consistent with the Functional Model, there cannot be an assumption that the entity owning the generation will be the same entity providing the BA function. It is the responsibility of the party interconnecting to make appropriate arrangements with a Balancing Authority to ensure its Facilities are within the BA's metered boundaries, which also serves to facilitate the process of the coordination between the two entities that will be required under numerous other standards upon the start of operation. Under 4.3, the Generator Owner is responsible for confirming that the party interconnecting has made appropriate provisions with a Balancing Authority to operate within its metered boundaries.

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

Initial posting for 45-day formal comment period with ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	9/24/2020
SAR posted for comment	11/12 – 12/12/2020

Anticipated Actions	Date
45-day formal or informal comment period with ballot	December 2021
45-day formal or informal comment period with additional ballot	March 2022
45-day formal or informal comment period with additional ballot	June 2022
10-day final ballot	August 2022
Board adoption	November 2022

New or Modified Term(s) Used in NERC Reliability Standards

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Term(s):

~~Text~~None

A. Introduction

1. **Title:** Facility Interconnection Studies
2. **Number:** FAC-002-~~34~~
3. **Purpose:** To study the impact of interconnecting new or ~~materially modified~~changed—Facilities on the Bulk Electric System.
4. **Applicability:**
 - 4.1. **Functional Entities:**
 - 4.1.1. Planning Coordinator
 - 4.1.2. Transmission ~~Power~~Planner
 - 4.1.3. Transmission Owner
 - 4.1.4. Distribution Provider
 - 4.1.5. Generator Owner
 - 4.1.6. Applicable Generator Owner
 - 4.1.6.1. Generator Owner with a fully executed Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system.
5. **Effective Date:** See Implementation Plan for Project 2020-05.

B. Requirements and Measures

- R1.** Each Transmission Planner and each Planning Coordinator shall study the reliability impact of: (i) interconnecting new generation, transmission, or electricity end-user Facilities and (ii) ~~materially modifying~~ existing interconnections of generation, transmission, or electricity end-user Facilities seeking to make a qualified change as defined by the Planning Coordinator under Requirement R6. The following shall be studied: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
- 1.1.** The reliability impact of the new interconnection, or ~~materially modified~~ existing interconnection seeking to make a qualified change as defined by the Planning Coordinator under Requirement R6, on affected system(s);
 - 1.2.** Adherence to applicable NERC Reliability Standards; regional and Transmission Owner planning criteria; and Facility interconnection requirements;
 - 1.3.** Steady-state, short-circuit, and dynamics studies, as necessary, to evaluate system performance under both normal and contingency conditions; and
 - 1.4.** Study assumptions, system performance, alternatives considered, and coordinated recommendations. While these studies may be performed independently, the results shall be evaluated and coordinated by the entities involved.
- M1.** Each Transmission Planner or each Planning Coordinator shall have evidence (such as study reports, including documentation of reliability issues) that it met all requirements in Requirement R1.
- R2.** Each Generator Owner seeking to interconnect new generation Facilities, or ~~to materially modify~~ existing interconnections of generation Facilities seeking to make a qualified change as defined by the Planning Coordinator under Requirement R6, shall coordinate and cooperate on studies with its Transmission Planner or Planning Coordinator, including but not limited to the provision of data as described in R1, Parts 1.1-1.4. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
- M2.** Each Generator Owner shall have evidence (such as documents containing the data provided in response to the requests of the Transmission Planner or Planning Coordinator) that it met all requirements in Requirement R2.
- R3.** Each Transmission Owner and each Distribution Provider seeking to interconnect new transmission Facilities or electricity end-user Facilities, or ~~to materially modify~~ existing interconnections of transmission Facilities seeking to make a qualified change as defined by the Planning Coordinator under Requirement R6, or electricity end-user Facilities, shall coordinate and cooperate on studies with its Transmission Planner or Planning Coordinator, including but not limited to the provision of data as described in R1, Parts 1.1-1.4. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
- M3.** Each Transmission Owner and each Distribution Provider shall have evidence (such as documents containing the data provided in response to the requests of the

Transmission Planner or Planning Coordinator) that it met all requirements in Requirement R3.

- R4.** Each Transmission Owner shall coordinate and cooperate with its Transmission Planner or Planning Coordinator on studies regarding requested new or ~~materially modified-existing~~ interconnections seeking to make a qualified change as defined by the Planning Coordinator under Requirement R6, to its Facilities, including but not limited to the provision of data as described in R1, Parts 1.1-1.4. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
- M4.** Each Transmission Owner shall have evidence (such as documents containing the data provided in response to the requests of the Transmission Planner or Planning Coordinator) that it met all requirements in Requirement R4.
- R5.** Each applicable Generator Owner shall coordinate and cooperate with its Transmission Planner or Planning Coordinator on studies regarding requested interconnections to its Facilities, including but not limited to the provision of data as described in R1, Parts 1.1-1.4. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
- M5.** Each applicable Generator Owner shall have evidence (such as documents containing the data provided in response to the requests of the Transmission Planner or Planning Coordinator) that it met all requirements in Requirement R5.
- R6.** Each Planning Coordinator shall maintain a publicly available definition of qualified change for the purposes of facility interconnection. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
- M6.** Each Planning Coordinator shall have evidence that it has maintained a publicly available definition of qualified change

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, Transmission Planner, Transmission Owner, Distribution Provider, Generator Owner and applicable Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

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

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

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and 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 #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	Long-term Planning	Medium	The Transmission Planner or Planning Coordinator studied the reliability impact of: (i) interconnecting new generation, transmission, or electricity end-user Facilities, and (ii) ~~materially modifying~~ existing interconnections of generation, transmission, or electricity end-user Facilities <u>seeking to make a qualified change as defined by the Planning Coordinator under Requirement R6</u> , but failed to study one of the Parts (R1, 1.1-1.4).	The Transmission Planner or Planning Coordinator studied the reliability impact of: (i) interconnecting new generation, transmission, or electricity end-user Facilities, and (ii) ~~materially modifying~~ existing interconnections of generation, transmission, or electricity end-user Facilities <u>seeking to make a qualified change as defined by the Planning Coordinator under Requirement R6</u> , but failed to study two of the Parts (R1, 1.1-1.4).	The Transmission Planner or Planning Coordinator studied the reliability impact of: (i) interconnecting new generation, transmission, or electricity end-user Facilities, and (ii) ~~materially modifying~~ existing interconnections of generation, transmission, or electricity end-user Facilities <u>seeking to make a qualified change as defined by the Planning Coordinator under Requirement R6</u> , but failed to study three of the Parts (R1, 1.1-1.4).	The Transmission Planner or Planning Coordinator failed to study the reliability impact of: interconnecting new generation, transmission, or electricity end-user Facilities, and (ii) ~~materially modifying~~ existing interconnections of, generation, transmission, or electricity end-user Facilities <u>seeking to make a qualified change as defined by the Planning Coordinator under Requirement R6</u> .

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2.	Long-term Planning	Medium	The Generator Owner seeking to interconnect new generation Facilities, or ~~to materially modify~~ existing interconnections of generation Facilities <u>seeking to make a qualified change as defined by the Planning Coordinator under Requirement R6</u> , coordinated and cooperated on studies with its Transmission Planner or Planning Coordinator, but failed to provide data necessary to perform studies as described in one of the Parts (R1, 1.1-1.4).	The Generator Owner seeking to interconnect new generation Facilities, or ~~to materially modify~~ existing interconnections of generation Facilities <u>seeking to make a qualified change as defined by the Planning Coordinator under Requirement R6</u> , coordinated and cooperated on studies with its Transmission Planner or Planning Coordinator, but failed to provide data necessary to perform studies as described in two of the Parts (R1, 1.1-1.4).	The Generator Owner seeking to interconnect new generation Facilities, or ~~to materially modify~~ existing interconnections of generation Facilities <u>seeking to make a qualified change as defined by the Planning Coordinator under Requirement R6</u> , coordinated and cooperated on studies with its Transmission Planner or Planning Coordinator, but failed to provide data necessary to perform studies as described in three of the Parts (R1, 1.1-1.4).	The Generator Owner seeking to interconnect new generation Facilities, or ~~to materially modify~~ existing interconnections of generation Facilities <u>seeking to make a qualified change as defined by the Planning Coordinator under Requirement R6</u> , failed to coordinate and cooperate on studies with its Transmission Planner or Planning Coordinator.
R3.	Long-term Planning	Medium	The Transmission Owner or Distribution Provider seeking to interconnect new	The Transmission Owner, or Distribution Provider seeking to interconnect new	The Transmission Owner or Distribution Provider seeking to interconnect new	The Transmission Owner, or Distribution Provider seeking to interconnect new

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			transmission Facilities or electricity end-user Facilities, or ~~to~~ materially modify existing interconnections of transmission Facilities seeking to make a qualified change as defined by the Planning Coordinator under Requirement R6, or electricity end-user Facilities, coordinated and cooperated on studies with its Transmission Planner or Planning Coordinator, but failed to provide data necessary to perform studies as described in one of the Parts (R1, 1.1-1.4).	transmission Facilities or electricity end-user Facilities, or ~~to~~ materially modify existing interconnections of transmission Facilities seeking to make a qualified change as defined by the Planning Coordinator under Requirement R6, or electricity end-user Facilities, coordinated and cooperated on studies with its Transmission Planner or Planning Coordinator, but failed to provide data necessary to perform studies as described in two of the Parts (R1, 1.1-1.4).	transmission Facilities or electricity end-user Facilities, or ~~to~~ materially modify existing interconnections of transmission Facilities seeking to make a qualified change as defined by the Planning Coordinator under Requirement R6, or electricity end-user Facilities, coordinated and cooperated on studies with its Transmission Planner or Planning Coordinator, but failed to provide data necessary to perform studies as described in three of the Parts (R1, 1.1-1.4).	transmission Facilities or electricity end-user Facilities, or ~~to~~ materially modify existing interconnections of transmission Facilities seeking to make a qualified change as defined by the Planning Coordinator under Requirement R6, or electricity end-user Facilities, failed to coordinate and cooperate on studies with its Transmission Planner or Planning Coordinator.
R4.	Long-term Planning	Medium	The Transmission Owner coordinated and cooperated on	The Transmission Owner coordinated and cooperated on	The Transmission Owner coordinated and cooperated on	The Transmission Owner failed to coordinate and

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			studies with its Transmission Planner or Planning Coordinator regarding requested new or ~~materially modified~~ <u>existing</u> interconnections <u>seeking to make a qualified change as defined by the Planning Coordinator under Requirement R6</u> to its Facilities, but failed to provide data necessary to perform studies as described in one of the Parts (R1, 1.1-1.4).	studies with its Transmission Planner or Planning Coordinator regarding requested new or ~~materially modified~~ <u>existing</u> interconnections <u>seeking to make a qualified change as defined by the Planning Coordinator under Requirement R6</u> to its Facilities, but failed to provide data necessary to perform studies as described in two of the Parts (R1, 1.1-1.4).	studies with its Transmission Planner or Planning Coordinator regarding requested new or ~~materially modified~~ <u>existing</u> interconnections <u>seeking to make a qualified change as defined by the Planning Coordinator under Requirement R6</u> to its Facilities, but failed to provide data necessary to perform studies as described in three of the Parts (R1, 1.1-1.4).	cooperate on studies with its Transmission Planner or Planning Coordinator regarding requested new or ~~materially modified~~ <u>existing</u> interconnections <u>seeking to make a qualified change as defined by the Planning Coordinator under Requirement R6</u> to its Facilities.
R5.	Long-term Planning	Medium	The applicable Generator Owner coordinated and cooperated on studies with its Transmission Planner or Planning Coordinator regarding requested	The applicable Generator Owner coordinated and cooperated on studies with its Transmission Planner or Planning Coordinator regarding requested	The applicable Generator Owner coordinated and cooperated on studies with its Transmission Planner or Planning Coordinator regarding requested	The applicable Generator Owner failed to coordinate and cooperate on studies with its Transmission Planner or Planning Coordinator regarding

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			interconnections to its Facilities, but failed to provide data necessary to perform studies as described in one of the Parts (R1, 1.1-1.4).	interconnections to its Facilities, but failed to provide data necessary to perform studies as described in two of the Parts (R1, 1.1-1.4).	interconnections to its Facilities, but failed to provide data necessary to perform studies as described in three of the Parts (R1, 1.1-1.4).	requested interconnections to its Facilities.
<u>R6.</u>	<u>Long-term Planning</u>	<u>Lower</u>	<u>N/A</u>	<u>N/A</u>	<u>N/A</u>	<u>The Planning Coordinator did not maintain a publicly available definition of qualified change for the purposes of facility interconnection.</u>

D. Regional Variances

None.

E. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	January 13, 2006	Removed duplication of “Regional Reliability Organizations(s).	Errata
1	August 5, 2010	Modified to address Order No. 693 Directives contained in paragraph 693. Adopted by the NERC Board of Trustees.	Revised
1	February 7, 2013	R2 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.	
1	November 21, 2013	R2 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	
2		Revisions to implement the recommendations of the FAC Five-Year Review Team.	Revision under Project 2010-02
2	August 14, 2014	Adopted by the Board of Trustees.	
2	November 6, 2014	FERC letter order issued approving FAC-002-2.	
3	February 6, 2020	Adopted by NERC Board of Trustees.	Revisions under Project 2017-07
<u>4</u>	<u>TBD</u>	<u>Adopted by NERC Board of Trustees.</u>	<u>Revisions under Project 2020-05</u>

Guidelines and Technical Basis

~~Entities should have documentation to support the technical rationale for determining whether an existing interconnection was “materially modified.” Recognizing that what constitutes a “material modification” will vary from entity to entity, the intent is for this determination to be based on engineering judgment.~~

Standard Authorization Request (SAR)

Complete and submit this form, with attachment(s) to the [NERC Help Desk](#). Upon entering the Captcha, please type in your contact information, and attach the SAR to your ticket. Once submitted, you will receive a confirmation number which you can use to track your request.

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-026-1 Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions, MOD-027-1 Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions	
Date Submitted:		June 10, 2020	
SAR Requester			
Name:		Allen Shriver, Chair Jeffery Billo, Vice Chair	
Organization:		Inverter-Based Resource Performance Task Force (IRPTF)	
Telephone:		Email:	Allen.Schrivier@NextEraEnergy.com Jeff.Billo@ercot.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?):			
The NERC Inverter-based Resource Performance Task Force (IRPTF) undertook an effort to perform a comprehensive review of all NERC Reliability Standards to determine if there were any potential gaps or improvements based on the work and findings of the IRPTF. The IRPTF identified several issues as part of this effort and documented its findings and recommendations in a white paper. The "IRPTF Review of NERC Reliability Standards White Paper" was approved by the Operating Committee and the Planning Committee in March 2020. Among the findings noted in the white paper, the IRPTF identified issues with MOD-026-1 and MOD-027-1 that should be addressed.			

Requested information
MOD-026-1 and MOD-027-1 require, among other things, GOs to provide verified dynamic models to their Transmission Planner (TP) for the purposes of power system planning studies. Both standards contain language that is specific to synchronous generators and is not applicable to inverter-based resources (IBRs). For example, sub-requirement 2.1.3 in MOD-026-1 states that each verification shall include “model structure and data including, but not limited to reactance, time constants, saturation factors, total rotational inertia...” The standards should be revised to clarify the applicable requirements for synchronous generators and IBRs. For example, total rotational inertia should not be required for IBRs, while voltage ride-through control settings should only be required of IBRs and not synchronous generators. Additionally, to some degree, all dynamic model parameters affect the response of a represented resource in dynamic simulations performed by power engineers. Accurate model response is required for the engineers to adequately study system conditions. Hence, it is crucial that all parameters in a model be verified in some way. However, a significant number of parameters in the models are not verified in the typical verification tests used to comply with MOD-026-1 and MOD-027-1. For example, the test currently used to comply with MOD-026-1 does not verify the model parameters associated with voltage control behavior during large disturbance conditions.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?): This SAR proposes to revise MOD-026-1 and MOD-027-1 and/or create a new standard to clarify requirements related to IBRs and to require sufficient model verification to ensure accurate generator representation in dynamic simulations.
Project Scope (Define the parameters of the proposed project): The proposed scope of this project is as follows: a. Update requirement language to better reflect all types of generation resources and not just synchronous resources. b. Consider ways to require sufficient model verification to ensure accurate generator representation in dynamic simulations of typical phenomena that would be studied by power system engineers, including large disturbances.
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 justification¹ 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): NERC MOD-026-1 focuses on verification of data for generator excitation control system or plant volt/var control functions and MOD-027-1 focuses on verification of data for turbine-governor and load control or active power-frequency control functions. Specifically, MOD-026-1 states in footnote 1 that the excitation control system for aggregate generating plants (i.e., wind and solar PV) includes the volt/var control system including the voltage regulator and reactive power control system controlling and coordinating

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

plant voltage and associated reactive capable resources. This language is slightly ambiguous on whether the verification activities include the inverter-level parameter values of the dynamic models. Various testing engineers and entities have stated that they are uncertain as to whether the standard applies to the plant-level parameters or the aggregate representation of the inverter-level settings.

Most commonly, verification test reports for inverter-based resources involve a small set of small disturbance tests including, but not limited to, the following:

- Capacitor switching test
- Plant-level voltage or reactive power reference step test
- Plant-level frequency reference step test
- Plant-level frequency play-in or step test

These tests do not perturb the generating resource such that the parameter values that dictate the large disturbance behavior of the resource are verified in any way. While some incorrect model parameters may be identified during these tests, the tests do not verify that the parameters selected for the model accurately capture the full dynamic behavior of the resource. This gives a false impression to TPs and PCs that the full set of parameters are verified for use in planning studies.

This issue is one of the predominant reasons why ride-through operation modes such as momentary cessation were able to persist and promulgate in IBRs without the knowledge of planners and system operators until the Blue Cut Fire and Canyon 2 Fire events exposed them. The dynamic models did not accurately represent this large disturbance behavior due to the model deficiency and because certain key parameters that govern large disturbance response were incorrectly parameterized. However, many of the same plants that entered momentary cessation mode during these events were able to provide verification reports that demonstrated that the small disturbance behavior driven mainly by plant-level control settings reasonably matched modeled performance in compliance with these standards.

Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):

The SAR proposes to clarify and address gaps in the requirements in MOD-026-1 and MOD-027-1. The cost impact is unknown.

Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):

The abovementioned reliability gap exists for both synchronous generators and IBRs. However, it is potentially more severe for IBRs since their behavior is based more on programmable control functions than for synchronous generators which have behavior that is based more on the physical characteristics of the machine. Additionally, the IRPTF noted that it is not feasible to stage large disturbances for verification purposes, so other methods for verification of model performance under large disturbance conditions may need to be developed.

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

Requested information
Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Transmission Planner, Generator Owner, Planning Coordinator
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.
This issue was captured in the “IRPTF Review of NERC Reliability Standards White Paper” which was approved by the Operating Committee and the Planning Committee. Additionally, the issue was discussed in the IRPTF-produced “Improvements to Interconnection Requirements for BPS-Connected Inverter-Based Resources” reliability guideline.
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)?
N/A
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 IRPTF did not identify any alternatives since there are gaps in the existing language for MOD-026-1 and MOD-027-1 that need to be resolved.

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	N/A

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
3	February 22, 2019	Standards Information Staff	Added instructions to submit via Help Desk
4	February 25, 2020	Standards Information Staff	Updated template footer

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:		Revise the Applicable Facilities of MOD-025, MOD-026, MOD-027, PRC-019 and PRC-024 Standards to comprehensively include all types of dynamic reactive resources (including static var systems and FACTS) and DC transmission systems used to provide Essential Reliability Services in the Bulk Electric System.	
Date Submitted:		February 24, 2020	
SAR Requester			
Name:		Hari Singh – Chair, System Analysis & Modeling Subcommittee (SAMS)	
Organization:		Xcel Energy	
Telephone:		303-571-7095	Email: hari.singh@xcelenergy.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?):			
Dynamic reactive resources used to provide Essential Reliability Services (ERS) in the BES include generation resources (rotating machine and inverter-based) as well as transmission connected dynamic reactive resources (power-electronics based). Existing reliability standards for verifying the capability, modeling and performance of dynamic reactive resources are only applicable to Facilities comprising generation resources. Augmenting the applicability of these standards to include (non-generation) transmission-connected reactive resources – both rotating machine (i.e. synchronous condenser) and power-electronics based – will enhance the BES reliability by ensuring that the capability, models and performance is verified and validated for all varieties of dynamic reactive resources utilized in providing ERS in the BES.			

Requested information
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
Augment the “Applicability – Facilities” and “Applicability-Functional Entities” sections in MOD-025, MOD-026, MOD-027, PRC-019 and PRC-024 reliability standards to address (non-generation) transmission-connected dynamic reactive resources – both rotating machine (i.e. synchronous condenser) and power-electronics based. Also modify Requirements (including applicable attachments) as needed to ensure they continue to address the additional Facilities. As needed, also define new Glossary Terms for all or some of the transmission-connected dynamic reactive devices noted in the SAMS white-paper “ <i>Transmission Connected Dynamic Reactive Resources – Assessment of Applicability in Reliability Standards</i> ”.
Project Scope (Define the parameters of the proposed project):
Revise the “Applicability – Facilities” section, “Applicability – Functional Entities” section, and Requirements (including applicable attachments) as needed in MOD-025, MOD-026, MOD-027, PRC-019 and PRC-024 reliability standards to comprehensively address all varieties of transmission-connected dynamic reactive resources that are utilized in providing ERS in the BES.
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 “Applicability – Facilities” and “Applicability-Functional Entities” sections in MOD-025, MOD-026, MOD-027, PRC-019 and PRC-024 reliability standards will be revised to address (non-generation) transmission-connected dynamic reactive resources based on the recommendations summarized in Table 1 of the SAMS white-paper “ <i>Transmission Connected Dynamic Reactive Resources – Assessment of Applicability in Reliability Standards</i> ”. The white-paper also provides the technical justifications for the recommended revisions and the associated reliability benefits. Also modify Requirements (including applicable attachments) as needed to ensure they continue to address the additional Facilities. As needed, also define new Glossary Terms for all or some of the transmission-connected dynamic reactive devices noted as items 1.a – 1.j in the Additional Considerations section of the SAMS white-paper.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
Unknown
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (e.g. Dispersed Generation Resources):
Power-electronics based transmission-connected reactive resources – also known as FACTS (Flexible AC Transmission System) devices – such as: Static Var Compensator (SVC), Static Synchronous Compensator (STATCOM), HVDC Links (LCC or VSC).
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

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
Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Transmission Owners in addition to the existing Functional Entities
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.
<i>"Transmission Connected Dynamic Reactive Resources – Assessment of Applicability in Reliability Standards"</i> white-paper approved by SAMS members.
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)?
PRC-019 SAR requested by SPCS and PRC-024 SAR requested by IRPTF
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.
No viable alternatives were found by SAMS.

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
<i>e.g.</i> 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

Standard Authorization Request (SAR)

Complete and submit this form, with attachment(s) to the [NERC Help Desk](#). Upon entering the Captcha, please type in your contact information, and attach the SAR to your ticket. Once submitted, you will receive a confirmation number which you can use to track your request.

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-025-2 Verification and Data Reporting of Generator Capability		
Date Submitted:	10/19/2020		
SAR Requester			
Name:	Shawn Patterson, Chair		
Organization:	NERC Power Plant Modeling Verification Task Force (PPMVTF)		
Telephone:	303-445-2311	Email:	spatterson@usbr.gov
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?):			
The current industry need for this standards project is that industry implementation of MOD-025-2 has not resulted in useful unit capability data being provided for planning models of generating resources and synchronous condensers (i.e., the purpose statement of the standard). The primary reliability benefit of this project will be to correct these issues such that suitable and accurate data can be established through the verification activities performed by respective equipment owners. BPS planning assessments rely on accurate data, including machine active and reactive power capability, to identify potential reliability risks and develop mitigating actions for those risks. The current MOD-025-2 verification testing activities require significant time, expertise, and coordination; however, they do not result in data that should be used by planners for modeling purposes. The current standard does allow for optional calculations to be performed to help facilitate better information sharing; however, calculations are not required nor can be used in many cases when auxiliary equipment limits or system operating conditions prohibit reaching the actual machine capability or limiters. This standards project will address these issues.			

Requested information

Other benefits of this standards project to address issues with MOD-025-2 include, but are not limited to, the following:

- Preventing over- or under-estimation of generating facility active and reactive power, which could lead to potential reliability risks or unnecessary and expensive solutions to mitigate
- Identifying limitations within a generating facility that could constrain the resource from reaching the expected active/reactive capability at any given time
- More clearly communicating the necessary data to be used for modeling the respective resources in steady-state power flow models
- Ensure that the data users are part of the verification process to ensure that the necessary and usable data is provided and utilized appropriately
- Ensure that raw test data alone is not used for resource modeling, but is analyzed, adjusted, and contextualized to account for measured system conditions
- Coordinating with PRC-019 activities to develop a composite capability curve, inclusive of equipment capabilities, limiters, and other plant limitations to develop an appropriate capability curve
- Ensuring that other means of verification (other than testing) can be more effectively leveraged to gather necessary and suitable data for verifying plant/machine capability

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

The intent of this standard revision project is to address the issues that exist with MOD-025-2 regarding verification and data reporting of generator active and reactive power capability (and any other relevant equipment capability). Currently, implementation of the standard rarely produces data that is suitable for planning models (i.e., the stated purpose of the standard). The vast majority of testing cases are limited by limits within the plant or system operating conditions that prohibit the generating resource from reaching its “composite capability curve” – the equipment capability or associated limiters. The goal of the proposed project is to:

- Ensure that testing and other verification activities produce useful data for verification of plant active and reactive power capability
- Ensure that the data is used by Transmission Planners and Planning Coordinators in an appropriate manner, with a sufficient degree of analysis prior to use
- Ensure that the data is applicable and usable by the Transmission Planner and Planning Coordinator for reliability studies
- Ensure Generator Owners appropriately identify limits within their generating resources (and synchronous condensers), and effectively communicate those limits to Transmission Planners and Planning Coordinators for the purposes of modeling these resources in reliability studies

Requested information

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

The scope of this project is to modify MOD-025-2 to ensure that data provided through verification activities performed by applicable Generator Owner or Transmission Owners produce suitable data for the purposes of developing accurate planning models in Transmission Planner and Planning Coordinator reliability studies. The project should consider, at a minimum, the following:

1. Revisions to MOD-025-2 to ensure that verification activities produce data and information that can be used by Transmission Planners and Planning Coordinators for the purposes of developing accurate and reasonable plant active and reactive capability data (including possibly representation of the “composite capability curve” inclusive of capability and limiters, where applicable).
2. Ensure that each Planning Coordinator and the area Transmission Planners develop requirements for the Planning Coordinator area real and reactive capability data verification
3. Ensure that Generator Owners provide the data specified by the Planning Coordinator and Transmission Planners for the Planning Coordinator area
4. Ensure that verification activities can apply other methods beyond only testing (or real-time data) that allow plant capability information, protection settings, PRC-019 reports, and other documentation to also complement the verification activities
5. Ensure that data provided by the applicable Generator Owners and Transmission Owners is analyzed and used appropriately by Transmission Planners and Planning Coordinators
6. Ensure that the data provided by Generator Owners, if different from tested values, is acceptable to the Planning Coordinator and Transmission Planners with the standard providing guidance on acceptable reactive capability reporting if system conditions prevent reaching actual capability.
7. Ensure alignment of the MOD-025 standard with MOD-032-1 regarding data submittals for annual case creation and PRC-019-2 regarding collection of information that can be effectively used for verification purposes. Ensure activities across standards can be applied to effectively meet the purpose of these standards, and avoid any potential overlap or duplication of activities. This is dependent on the success of bullet number 1.
8. Ensure that equipment limitations are documented and classified as expected (e.g., system voltage limit reached) or unexpected (e.g., plant tripped or excitation limiter reached unexpectedly). In cases of unexpected limitations reached, ensure that the equipment owner develops and implements a corrective action plan to address this unexpected limitation.

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 justification¹ 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 NERC PPMVTF developed <i>White Paper: Implementation of NERC Standard MOD-025-2</i>² that recommends NERC initiate a standards project to address these issues with MOD-025-2. The white paper provides a detailed description and technical justification of the gaps that exist in MOD-025-2 and how the current standard may be leading to inaccurate data being used in BPS reliability studies. Further, the NERC PPMVTF <i>Reliability Guideline: Power Plant Model Verification and Testing for Synchronous Machines</i>³ also describes in detail how testing activities per MOD-025-2 can lead to unusable data, and provides further guidance that a SDT could use to develop solutions to these issues.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project): The aforementioned NERC PPMVTF <i>White Paper: Implementation of NERC Standard MOD-025-2</i> includes an example of one Registered Entity's MOD-025 implementation costs (excluding cost of shifting the optimization of generation fleet assets due to minimum load testing requirements). The entity's average test cost was \$1,259 (897 tests) and \$4,326 per generator (261 generators). The verification testing of units generally results in transferring energy to a higher cost resource during the test period. Further, the data produced is often NOT suitable for planning studies, which does not serve the intended purpose of the standard and makes the added cost unjustified.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (e.g., Dispersed Generation Resources): The current MOD-025-2 was written around synchronous generation, although it is not specifically applicable only to synchronous generators. Therefore, the project should ensure the language is clear and concise regarding how to handle BES dispersed generating resources (e.g., wind, solar photovoltaic, and battery energy storage systems).
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): Generator Owner and Transmission Owner of synchronous condensers (asset owner that is in the best position to ascertain resource capability)

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 https://www.nerc.com/comm/PC/Power%20Plant%20Modeling%20and%20Verification%20Task%20Force/PPMVTF_White_Paper_MOD-025_Testing.pdf

³ https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_-_PPMV_for_Synchronous_Machines_-_2018-06-29.pdf

Requested information
Transmission Planner and Planning Coordinator (user of the information provided by the Generator Owner; currently has no responsibility of ensuring accurate data per current MOD-025-2 standard)
Do you know of any consensus building activities⁴ in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
The NERC PPMVTF White Paper, approved by NERC RSTC, details the challenges with MOD-025-2. The team deliberated this subject for a significant amount of time, and have identified major issues with the standard that need to be addressed by an SDT. The PPMVTF believes that a significant revision to MOD-025-2 is needed, that testing activities are useful and should be retained, but that the activities can focus on more effective means of collecting useful data for planning models. One dissenting opinion of PPMVTF membership believed the standard should be retired completely and not replaced with an alternative.
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 NERC standards development Project 2020-02 (Transmission-connected Dynamic Reactive Resources) SAR includes MOD-025-2, specifically addressing the applicability of transmission connected reactive devices in addition to generators and synchronous condensers. The SAR on PRC-019-2 submitted to NERC by the System Protection and Control Subcommittee is also related in that there is significant overlap of activities in PRC-019-2 and the development of planning models of machine capability.
This SAR could be combined with those portions of those SARs to address this problem effectively.
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.
There are two key industry reference documents on this subject: 1. NERC <i>Reliability Guideline: Power Plant Model Verification and Testing for Synchronous Machines</i>⁵ (July 2018) that provides recommended practices for synchronous machine capability testing. An appendix is devoted to MOD-025-2 testing, and highlights the challenges and inherent errors in MOD-025-2 to obtain useful data that can be applied for planning models. 2. NATF <i>Modeling Reference Document Reporting and Verification of Generating Unit Reactive Power Capability for Synchronous Machines</i>⁶ (April 2015) that describes testing activities per MOD-025-2 and means of ensuring data is sufficient for planning studies.

⁴ 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.

⁵ https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_-_PPMV_for_Synchronous_Machines_-_2018-06-29.pdf

⁶ <https://www.natf.net/docs/natf/documents/resources/planning-and-modeling/natf-reference-document-reporting-and-verification-of-generating-unit-reactive-power-capability-for-synchronous-machines.pdf>

Requested information

Neither industry reference document addresses the identified shortcomings of the standard described above and in NERC PPMVTF *White Paper: Implementation of NERC Standard MOD-025-2*.⁷ These reference materials help industry understand how to implement the standards using best practices, but do not address the reliability gaps created by the standard requirements themselves which is leading to inaccurate data being used in planning assessments.

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

⁷ https://www.nerc.com/comm/PC/Power%20Plant%20Modeling%20and%20Verification%20Task%20Force/PPMVTF_White_Paper_MOD-025_Testing.pdf

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
N/A	None identified.

For Use by NERC Only

SAR Status Tracking (Check off as appropriate).

☐ Draft SAR reviewed by NERC Staff	☐ Final SAR endorsed by the SC
☐ Draft SAR presented to SC for acceptance	☐ SAR assigned a Standards Project by NERC
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Version History

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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
3	February 22, 2019	Standards Information Staff	Added instructions to submit via Help Desk
4	February 25, 2020	Standards Information Staff	Updated template footer

Standard Authorization Request (SAR)

Complete and submit this form, with attachment(s) to the [NERC Help Desk](#). Upon entering the Captcha, please type in your contact information, and attach the SAR to your ticket. Once submitted, you will receive a confirmation number which you can use to track your request.

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 PRC-019 to address dispersed power producing resources		
Date Submitted:	4/7/2020		
SAR Requester			
Name:	Chair Jeffrey Iler & Vice Chair Bill Crossland on behalf of the		
Organization:	NERC System Protection and Control Subcommittee (SPCS)		
Telephone:	Chair: (614) 933-2373 Vice Chair: (216) 503-0613	Email:	Chair: jwiler@aep.com Vice Chair: bill.crossland@rfirst.org
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?):			
Reliability Standard PRC-019-2 addresses the reliability issue of miscoordination between generator capability, control systems, and protection functions. However, this standard was developed with a bias toward synchronous generation and does not sufficiently outline the requirements for all generation resource types. The purpose statement of the standard requires modification to be inclusive of all generation resource types. While this class of resources are currently included in the applicability of PRC-019-2, additional clarity is needed in specifying the aspects of dispersed power producing resources that should be coordinated. There are also issues within PRC-019-2 regarding synchronous generation that need to be corrected or clarified to remove ambiguity. These comprehensive updates align with the intent and spirit of the standard.			

Requested information
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?): This project will enhance reliability by maximizing a generators capability and its ability to support grid stability during system disturbances by requiring the coordination of control systems with equipment capabilities and protection functions of all generation resource types.
Project Scope (Define the parameters of the proposed project): The SDT should develop language that is relevant to all generation resource types. This will include modifications to the purpose statement, the applicability and requirements. Additionally, the SDT should consider modifying Inclusion I4 of the Bulk Electric System (BES) definition and the associated diagrams in the BES Reference Document.
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 justification¹ 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): 1. Applicable Facilities – Clarification of applicable facilities. a. Clarify Section 4.2.3.1 to state that it pertains to both the individual resources and the plant level voltage controls. [This section indicates that the individual generating units identified through Inclusion I4 of the Bulk Electric System (BES) definition are included only if voltage control for the facility is performed solely at the individual generator; thus, it is ambiguous as to whether this excludes the individual resources from the standard when the plant/facility level or park controller is being used for voltage control.]² b. Verify that static or dynamic reactive compensating devices (i.e., capacitor banks, static VAR compensators, STATCOMs, etc.) and synchronous condensers within BES generating facilities should be subject to the standard since they must be coordinated for protection and plant capability. [The language in footnote 1³ for Requirement R1 implies that reactive compensating devices are not applicable since they are not installed or activated on a generator. These devices are system level voltage regulators and have no effect on an individual inverter capability or limiter functions within an inverter control system; however, they are important to system VAR support and reliability. For example, Type 1 and Type 2 wind turbine generators (WTG) typically employ reactive compensating devices on the collector side of the generator step-up (GSU) transformer. In this case, reactive compensating devices are integral to supporting the systems reactive needs and enhances the reliability of the BES. These devices are not captured by the BES definition because they typically connect at voltages less than 100 kV; however, they should be applicable to the standard for asynchronous and non-rotating resources.]

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 Reference Section 4.10.10 of the [White Paper](#) from Project 2014-01 Standards Applicability for Dispersed Generation Resources

³ "Limiters or protection functions that are installed and activated on the generator or synchronous condenser."

Requested information

- c. Revise Inclusion I4 of the BES definition and Figures I4-1, I4-2, I4-3, and I4-4 in the BES Reference Document to accurately depict all generation resources.
- 2. **Requirement(s)** – Ensure the language is clear and inclusive of all generation resource types with respect to coordinating control systems, protection functions, and equipment capabilities.
 - d. **Controllers specific to dispersed power producing resources** – The standard is currently biased toward automatic voltage regulating (AVR) control systems used in conjunction with synchronous generation. The standard should address other control systems associated with dispersed power producing resources that are essential to reliability. Typically, inverters have a control system and the facility has a plant controller with a separate control system. The inverter has a control system that may operate in VAR control, Power Factor control, reactive power priority, or active power priority. The plant controller has a control system that may operate in Power Factor or Voltage Control modes. Coordination between any plant/park controller with individual resource control systems must be achieved to prevent unnecessary reduction of the resource.
 - e. **Momentary cessation** – “Momentary cessation” is a function within an Inverter-Based Resource (IBR) control system that reduces active and reactive current to zero when voltage is outside of a defined band.⁴ A reduction in active and/or reactive current can negatively impact reliability, especially during system perturbations, since the function prohibits the IBR from providing support to the BPS during these events.⁵ Ensuring clear language in this standard will ensure that BES generators are not unnecessarily ceasing current injection during abnormal conditions, that any cessation of current is coordinated with equipment capability, and that these functions do not pose a risk to BPS reliability.⁶ Revisions to the standard should consider methods or parameters to eliminate momentary cessation where possible, otherwise ensure it is coordinated with equipment capabilities of the inverter where it cannot be eliminated (for legacy equipment).
 - f. **Controller upgrades and/or changes (e.g., firmware)** – Specify that firmware upgrades are considered “system, equipment or setting changes” under Requirement R2 since these may impact dispersed power producing resource voltage control(s), protection, and limiters.
 - g. **Steady State Stability Limit (SSSL)** – Determine whether the “stability limits” language in Requirement R1.1.2 should be removed from the standard. [Manual SSSL theory is only applicable when a generator AVR is in manual operation mode; however, the standard specifically instructs an entity to assume the AVR is in automatic mode. This assumption is identified because it is industry standard to coordinate the underexcitation limiter with the SSSL since that is the most conservative approach for AVR operation. However, the

⁴ The voltage settings that cause momentary cessation are considered voltage protection settings within the inverter. Other functions within the inverter can cause momentary cessation to operate in a manner similar to a protective function. However, the focus for PRC-019 is on voltage-related functions.

⁵ Including dynamic active power-frequency control and reactive power-voltage control.

⁶ Momentary cessation has been observed in BPS solar PV facilities in all disturbances analyzed by NERC, including but not limited to the Blue Cut Fire, Canyon 2 Fire, Palmdale Roost, and Angeles Forest disturbances.

Requested information	
	protection settings typically coordinate with the machine capabilities and not the manual SSSL.] h. Synchronous condensers – If item ‘d’ remains in the standard, determine whether SSSL should be considered for synchronous condensers. [A synchronous condenser operates in a manner similar to a synchronous generator in terms of voltage regulation and the associated excitation control system. The electrical quantities for a synchronous condenser match the quantities specified in the manual SSSL methodology; however, the machine does not have a prime mover and cannot output real power. This drastically reduces the machines operating region since the unit will only be able to absorb or generate reactive power.] i. Stability limits for other types of generation resources – If item ‘d’ remains in the standard, verify whether a SSSL must be considered for asynchronous and non-rotating generation resources. [Current references to stability limits are all relevant to synchronous machines (AVR in manual mode, fixed excitation voltage, etc.). If consideration of stability is necessary, provide a methodology or implementation guidance for the industry to use (e.g. small signal stability, etc.)]. j. Voltage drop across dispersed power producing resource collector system – Determine whether the voltage drop across the collector system, bus, generator step-up (GSU) transformer, or other facilities should be considered for coordination. k. Time frame to perform coordination – Revise the language in Requirement R2 to remove ambiguity surrounding the timeframe for performing coordination. [The current language can be interpreted as allowing the coordination to be performed 90 days after the “implementation of systems, equipment, or setting changes.” This would allow an entity to put a unit back into service without performing coordination; thus, jeopardizing reliability. The original SDT has confirmed that the 90-day time frame was for scenarios in which an entity discovered a miscoordination.]
	Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
	Costs may include updating firmware on dispersed power producing resources, individual IBRs, park/plant controllers, and other associated equipment, and will vary depending on the approach taken to address the reliability-related risks stated above.
	Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (e.g., Dispersed Generation Resources):
	Synchronous generation and dispersed power producing resources may be impacted by the revisions.
	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):
	The team should be made up predominantly by protection engineers with a background in generation protection (synchronous/dispersed power producing resources); preferably industry experts in this field. Additionally, IBR manufacturers and Engineering, Procurement and Construction firms familiar with

Requested information
dispersed power producing resources should be included because of their inherent knowledge of the capabilities and limitations of dispersed power producing resources. Team members should have extensive understanding of generation protection concepts/schemes. In addition, they should have some knowledge of control systems (AVR, IBR's, etc.)
Do you know of any consensus building activities ⁷ in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
No
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so, which standard(s) or project number(s)?
No
Are there alternatives (e.g., guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.
The NERC SPCS initially attempted to develop Implementation Guidance (IG); however, while developing the IG, the group determined that the standard required additional clarity for IBRs.

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.
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☐ 4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
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☐ 8. Bulk power systems shall be protected from malicious physical or cyber attacks.

⁷ 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
<i>None</i>	None

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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

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4	February 25, 2020	Standards Information Staff	Updated template footer

Standard Authorization Request (SAR)

Complete and submit this form, with attachment(s) to the [NERC Help Desk](#). Upon entering the Captcha, please type in your contact information, and attach the SAR to your ticket. Once submitted, you will receive a confirmation number which you can use to track your request.

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:		VAR-002-4.1 Generator Operation for Maintaining Network Voltage Schedules	
Date Submitted:		June 10, 2020	
SAR Requester			
Name:		Allen Shriver, Chair Jeffery Billo, Vice Chair	
Organization:		Inverter-Based Resource Performance Task Force (IRPTF)	
Telephone:		Email:	
Allen: 561-904-3234 Jeffery: 512-248-6334		Allen.Schrive@NextEraEnergy.com Jeff.Billo@ercot.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?):			
The NERC Inverter-based Resource Performance Task Force (IRPTF) undertook an effort to perform a comprehensive review of all NERC Reliability Standards to determine if there were any potential gaps or improvements based on the work and findings of the IRPTF. The IRPTF identified several issues as part of this effort and documented its findings and recommendations in a white paper. The "IRPTF Review of NERC Reliability Standards White Paper" was approved by the Operating Committee and the Planning Committee in March 2020. Among the findings noted in the white paper, the IRPTF identified issues with VAR-002-4.1 that should be addressed. The purpose of VAR-002-4.1 is "to ensure generators provide reactive support and voltage control, within generating Facility capabilities, in order to protect equipment and maintain reliable operation of the Interconnection." Requirement R3 requires each Generator Operator (GOP) to notify its			

Requested information
Transmission Operator (TOP) of a status change on “the AVR, power system stabilizer, or alternative voltage controlling device within 30 minutes of the change.” Requirement R4 is similar in that it requires each GOP to notify its TOP of “a change in reactive capability due to factors other than a status change described in Requirement R3.” For dispersed power producing resources, it is not clear if a GOP is required to notify the TOP for the status change of a voltage controlling device on an individual generating unit. For example, if an IBR consisting of one hundred inverters has one inverter trip out of service, is the GOP required to notify the TOP per Requirement R3? NERC Project 2014-01 revised VAR-002 Requirement R4 to clarify that it is not applicable to individual generating units of dispersed power producing resources. The IRPTF did not identify any reason why Requirement R3 should be treated differently than Requirement R4 in this respect and recommended VAR-002-4.1 be modified to make this same clarification to Requirement R3.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?): This SAR proposes to revise VAR-002-4.1 to address ambiguities within the existing standard. The goal is to add clarity and address the ambiguity in the existing requirements.
Project Scope (Define the parameters of the proposed project): The proposed scope of this project is to clarify VAR-002-4.1 Requirement R3 in regards to whether the GOP of a dispersed power resource must notify its associated TOP of a status change of a voltage controlling device on an individual generating unit, for example if a single inverter goes offline in a solar PV resource.
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 justification¹ 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 Standards Drafting Team should clarify VAR-002-4.1 Requirement R3 in regards to whether the GOP of a dispersed power resource must notify its associated TOP of a status change of a voltage controlling device on an individual generating unit.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project): The SAR proposes to clarify VAR-002-4.1 Requirement R3. The cost impact is unknown, but it is expected to be minimal since it should only impact communication procedures.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (e.g., Dispersed Generation Resources): Dispersed power producing resources are made up of multiple individual generating units. It may be impractical, place an undue burden upon the associated GOPs and TOPs, and have no material reliability benefit to have GOPs notify TOPs in regards to the status change of a voltage controlling device on a single individual generating unit.

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
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):
Generator Operators and Generator Owners
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.
This issue was captured in the "IRPTF Review of NERC Reliability Standards White Paper" which was approved by the Operating Committee and the 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)?
N/A
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 IRPTF did not identify any alternatives since the language in VAR-002-4.1 needs clarification.

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	N/A

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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
3	February 22, 2019	Standards Information Staff	Added instructions to submit via Help Desk
4	February 25, 2020	Standards Information Staff	Updated template footer

Standard Authorization Request (SAR)

Complete and submit this form, with attachment(s) to the [NERC Help Desk](#). Upon entering the Captcha, please type in your contact information, and attach the SAR to your ticket. Once submitted, you will receive a confirmation number which you can use to track your request.

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:	PRC-002-2 Disturbance Monitoring and Reporting Requirements		
Date Submitted:	April 8, 2021		
SAR Requester			
Name:	Terry Volkmann		
Organization:	Glencoe Light and Power NCR11444		
Telephone:	612-419-0672	Email:	terrylvolkman@gmail.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?):			
The purpose of PRC-002-2 ¹ is to have adequate sequence of events recording (SER) and fault recording (FR) data available to facilitate analysis of Bulk Electric System ² (BES) disturbances.			

¹ NERC Reliability Standard PRC-002-2 Disturbance Monitoring and Reporting Requirements

(<https://www.nerc.com/ layouts/15/PrintStandard.aspx?standardnumber=PRC-002-2&title=Disturbance%20Monitoring%20and%20Reporting%20Requirements&Jurisdiction=United%20States>)

² See Glossary of Terms Used in NERC Reliability Standards (https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf)

Requested information

Requirement R1, Part 1.2 infers that the notified BES Element owner is required to have FR data without regard to the identified BES bus owner having a connected BES Element for which FR data would be required for an applicable transformer or transmission line. By virtue of this notification, the transformer or transmission line BES Element owner is burdened with an obligation to have FR data and implicitly obligates these transformer or transmission line BES Element owners to either:

1. work with other BES Element (i.e., circuit breaker) owners to provide the data and data recording specification for which the transformer or transmission line owners must rely on for compliance, or
2. the transformer or transmission line BES Element owner must install its own equipment that is duplicative to the identified BES Bus recording equipment.

Below is Requirement R1 for reference:

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.

Notifications for FR data are being sent to BES Element owners that extend well beyond the BES bus boundary described in PRC-002-2 Attachment 1 as “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.” Notifying BES Element owners beyond this boundary unnecessarily obligates the BES Element (i.e., transformer or transmission line) owner to Requirement R3, including joint owners.

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

The goal of the proposed project is to clarify the necessary notifications in Requirement R1, Part 1.2 relative to FR data, and clearly identify the BES Element owners that need to have FR data for transformers and transmission lines with the associated identified bus.

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

The scope should include modifying Requirement R1, Part 1.2 to clarify notifications, which may include but is not limited to separating the SER data and/or FR data regarding notification. Additionally, Requirement R3 should be modified so that it is abundantly clear to the applicable Transmission Owner

Requested information

and Generator Owner when their BES Element must have FR data for an applicable transformer or transmission line.

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 justification³ 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 Transmission Owner (TO) applying the method in Attachment 1 who identifies a BES bus is in the ideal position to know which BES Elements (i.e., circuit breakers, transformer and transmission line) are connected to a single BES bus that includes physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid. Additionally, the identified BES bus owner should know who owns the particular BES Element (i.e., circuit breaker) that need FR data to capture disturbances on generators, transformers and transmission lines as identified in Requirement R3. Owners of BES Elements beyond the physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid should not be notified, unless their FR data is needed to complete the identified BES bus FR data.

Requirement R1, Part 1.1 uses a method and BES bus definition⁴ outlined in Attachment 1 to identify BES buses that require SER data and/or FR data. Part 1.2 requires the notification of other BES Element owners connected to the identified BES bus under Requirement R1, Part 1.1. As currently written, a notification is required regardless of whether the identified BES bus owner has FR data for the intended BES Element (i.e., transformer or transmission line) or owns the BES Elements directly connected to the identified BES bus. Requirement R1, Part 1.2 should be modified such that only the directly connected BES Element owner to the identified BES bus at the same voltage level within the same physical location sharing a common ground grid of the identified BES bus shall have FR data.

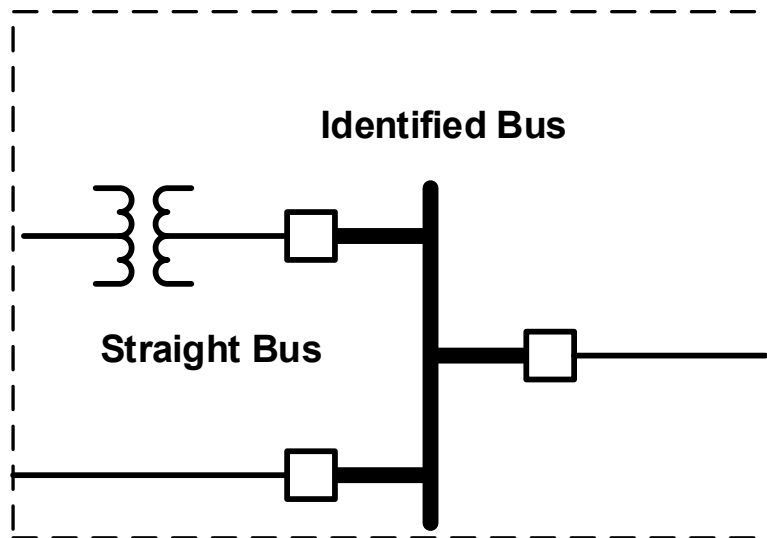
This will eliminate unnecessary notifications and obligations transformer and transmission line owners to compel other entities to have FR data when there is no authority to do so. In these cases, the other BES Element owner(s) have to rely on FR data from another entity that does not have the obligation under the standard

Additionally, clarifying the BES Element for which FR data is required will reduce auditing needs resulting from notifying BES Element owner who should not be responsible to have FR data as well as reducing the cost burden of meeting the reliability need for FR data.

³ 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.

⁴ Attachment 1, 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.

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The above figure of a straight bus is the simplest BES bus configuration contained within a common ground grid. Only the BES circuit breakers are connected to the identified BES bus. In this case it is clear concerning SER data in Requirement R2 because the circuit breaker is “directly connected.”

However, to achieve the need for FR data in Requirement R3, the identified BES bus owner notifies the transformer and transmission line owners under Requirement R, Part 1.2 thus obligating them to have FR data where the circuit breaker is directly connected and the logical BES Element to record FR data.

Under the current Requirement R3, the notified GO or TO transformer or line owner will need to contact the circuit breaker owner in hope of obtaining FR Data or install their own equipment. The GO or TO cannot compel the circuit breaker owner to have FR data. Additionally, relying on another entity that has no reliability responsibility for complying with PRC-002-2 places the transformer or transmission line owner at risk if the other entity fails to have the necessary and adequate FR data. The intent of the standard in Requirement R3 is to have FR data associated with all applicable BES Elements at a single BES bus that includes physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid of the identified BES bus. Requirement R1, Part 1.2 should only require notification to the BES Element (i.e., circuit breaker) owner directly connected with the identified BES bus.

Having the appropriate BES Elements identified at the same voltage level within the same physical location sharing a common ground grid that require SER and/or FR data will help facilitate obtaining data by only having to seek the data from those entities directly connected to the identified BES bus. However, the current standard could be interpreted that generation, transformer and transmission line owners could have FR data that is recorded at a location remote to the identified BES bus. As such, any modifications should consider alternative approaches that will achieve the intent of the standard while reducing associated cost and compliance burdens.

Requested information
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
None, the proposed modification above eliminates the unnecessary cost of being required to have FR data due to expanded notifications and the administrative burden to transformer and transmission line owners when these entities generally do not own the BES Elements that actually record the FR data.
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):
Transmission Owner and Generation Owner
Do you know of any consensus building activities ⁵ 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)?
A SAR was submitted by the NERC Inverter-based Resource Performance Task Force (IRPTF) to address potential gaps and improvements based on the work and findings of the IRPTF was authorized for posting by the NERC Standards Committee on January 20, 2021.
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.
Standard Implementation Guide or Practice Guide could provide the necessary clarity; however, these documents cannot change the strict language of the PRC-002-2 Reliability Standard. Nothing is being considered at the present time.

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.

⁵ Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

Reliability Principles	
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☒	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

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

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
None	

For Use by NERC Only

SAR Status Tracking (Check off as appropriate).	
☐ Draft SAR reviewed by NERC Staff	☐ Final SAR endorsed by the SC
☐ Draft SAR presented to SC for acceptance	☐ SAR assigned a Standards Project by NERC
☐ DRAFT SAR approved for posting by the SC	

	☐ 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
3	February 22, 2019	Standards Information Staff	Added instructions to submit via Help Desk
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Standard Authorization Request (SAR)

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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.

Requested information			
SAR Title:	PRC-002-2 Disturbance Monitoring and Reporting Requirements		
Date Submitted:	June 10, 2020		
SAR Requester			
Name:	Allen Shriver, Chair Jeffery Billo, Vice Chair		
Organization:	Inverter-Based Resource Performance Task Force (IRPTF)		
Telephone:	Allen: 561-904-3234 Jeffery: 512-248-6334	Email:	Allen.Shriver@NextEraEnergy.com Jeff.Billo@ercot.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?):			
The NERC Inverter-based Resource Performance Task Force (IRPTF) undertook an effort to perform a comprehensive review of all NERC Reliability Standards to determine if there were any potential gaps or improvements based on the work and findings of the IRPTF. The IRPTF identified several issues as part of this effort and documented its findings and recommendations in a white paper. The "IRPTF Review of NERC Reliability Standards White Paper" was approved by the Operating Committee and the Planning Committee in March 2020. Among the findings noted in the white paper, the IRPTF identified issues with PRC-002-2 that should be addressed. The purpose of PRC-002-2 is to have adequate data available to facilitate analysis of BES disturbances. Requirements R1 and R5 specify where sequence of events recording (SER) and fault recording (FR) data, and where dynamic Disturbance recording (DDR) data, respectively, are required in the Bulk Electric System (BES).			

Requested information

Requirements R1 and R5 are written with a focus on synchronous machine dominated systems with periodic review of monitoring equipment needs for the system. The BES elements with short circuit MVA in the top 20% are typically elements at baseload generating plants with multiple generating units or BES elements within a heavily meshed transmission network usually close to large load centers. Inverter-based resources (IBRs) do not contribute much fault current and are usually interconnected in remote parts of the system. As such, the short circuit MVA for the point of interconnection (POI) bus and nearby BES buses is not expected to be in the top 20%. Hence, BES buses near these resources are more likely to be omitted from requiring SER and FR data monitoring. In addition, most IBRs do not meet the nameplate rating criteria outlined in Requirement R5. With increasing penetration of IBRs, it is important that some of these resources and nearby BES elements are monitored with DDR and SER/FR devices.

Recent disturbance analyses of events involving IBRs including the Blue Cut Fire and Canyon 2 Fire have demonstrated the lack of disturbance monitoring data available from these facilities and nearby BES buses to adequately determine the causes and effects of their behavior. None of the IBRs involved in these two events met the size criteria stated in PRC-002-2 to be required to have disturbance monitoring. Additionally, none of the buses near the IBRs met the criteria in Requirement R1 for being required to have SER and FR devices since the IBRs inherently produce very little fault current. This led to difficulty in adequately assessing the events.

With the changing resource mix and increasing penetration of IBRs, PRC-002-2 does not serve its intended purpose adequately. To the extent that the standard is already requiring monitoring devices and periodic assessments, the location requirements and associated periodic assessments need to be revised. These revisions are necessary so that required data is available for the purposes of post-mortem event analysis and identifying root causes of large system disturbances.

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

This SAR proposes to revise PRC-002-2 to address gaps within the existing standard. The goal is to modify the requirements to ensure adequate data is available and periodically assessed to facilitate the analysis of BES disturbances, including in areas of the Bulk Power System (BPS) that may not be covered by the existing requirements.

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

The proposed scope of this project is as follows:

- a. Consider ways to ensure that the identification and periodic assessment of BES and/or BPS buses for which SER and FR data is required provides adequate monitoring of BES Disturbances. This may include updates to supplemental information such as the previously provided "Median Method Excel Workbook".
- b. Consider ways to ensure that the identification and periodic assessment of BES and/or BPS Elements for which DDR data is required provides adequate monitoring of BES disturbances.
- c. Consider other manners in which to add to, modify or clarify the existing requirements to ensure adequate monitoring of BES disturbances.

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 justification¹ 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):

Per Requirement R1 (which uses criteria outlined in Attachment 1), Sequence of Event Recording (SER) and Fault Recording (FR) devices are required at BES buses with high short circuit MVA values. The methodology identifies the top 20 percent of BES buses with highest short circuit MVA values and requires a subset of these buses to be monitored for SER and FR data.

However, BES elements with short circuit MVA in the top 20% are typically elements at baseload generating plants with multiple generating units or BES elements within a heavily meshed transmission network usually close to large load centers. IBRs do not contribute much fault current and are usually interconnected in remote parts of the system. As such, the short circuit MVA for the point of interconnection (POI) bus and nearby BES buses is not expected to be in the top 20%. Hence, BES buses near these resources are more likely to be omitted from requiring SER and FR data monitoring, though it is possible that monitoring in these areas is needed for disturbance analysis, as was the case in the Blue Cut Fire and Canyon 2 Fire events.

Requirement R5, identifies BES locations based on a size criteria for generating resources and other critical elements such as HVDC, IROLs and elements of UVLS program, for which Dynamic Disturbance Recording (DDR) data is required. In regard to generation resources, it includes requirements for monitoring at sites with either gross individual nameplate rating of greater than or equal to 500 MVA or gross individual nameplate rating greater than or equal to 300 MVA where gross plant/facility aggregate nameplate rating is greater than or equal to 1000 MVA.

However, most IBRs do not meet the nameplate rating criteria outlined in Requirement R5. With increasing penetration of IBRs, it is important that some of these resources and nearby BES elements are monitored with DDR devices to ensure adequate coverage for disturbance analysis while balancing cost impacts.

Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):

The SAR proposes to modify PRC-002-2 requirements. The cost impact is unknown, however, the cost of disturbance monitoring hardware is approximately \$50,000 to \$100,000 per installation if the existing onsite equipment is not already set up for monitoring and storage.

Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (e.g., Dispersed Generation Resources):

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
IBRs contribute very little short circuit MVA and are typically smaller in aggregate nameplate rating when compared to legacy synchronous resources. The criteria for selecting disturbance monitoring locations should take this into account.
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, Reliability Coordinator, Generator Owner, Transmission 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.
This issue was captured in the “IRPTF Review of NERC Reliability Standards White Paper” which was approved by the Operating Committee and the Planning Committee. Additionally, the IRPTF produced “BPS-Connected Inverter-Based Resource Performance”(see Chapter 6) and “Improvements to Interconnection Requirements for BPS-Connected Inverter-Based Resources” reliability guidelines touch on monitoring considerations for IBRs.
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)?
N/A
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 IRPTF did not identify any alternatives since there is a gap in PRC-002-2.

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.

² Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

Reliability Principles

☐	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
None	N/A

For Use by NERC Only

SAR Status Tracking (Check off as appropriate).

☐ Draft SAR reviewed by NERC Staff	☐ Final SAR endorsed by the SC
☐ Draft SAR presented to SC for acceptance	☐ SAR assigned a Standards Project by NERC
☐ DRAFT SAR approved for posting by the SC	☐ 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
3	February 22, 2019	Standards Information Staff	Added instructions to submit via Help Desk
4	February 25, 2020	Standards Information Staff	Updated template footer

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 PRC-023-4	
Date Submitted:		October 19, 2020	
SAR Requester			
Name:		Jeff Iler, Chair & Bill Crossland, Vice Chair (on behalf of)	
Organization:		NERC System Protection and Control Subcommittee	
Telephone:		Email:	
Jeff: (614) 933-2373 Bill: (216) 503-0600		Jeff: jwiler@aep.com Bill: bill.crossland@rfirst.org	
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?):			
Requirement R2, in PRC-023-4, requires applicable functional entities to set their Out of Step Blocking¹ (OOSB) elements to allow tripping for faults during the loading conditions prescribed by Requirement R1. A requirement to allow tripping in a Standard whose intent is to block tripping, has led to some entities disabling their OOSB relays. Disabling of these relays could lead to tripping during stable power swings causing an increased reliability risk. OOSB relays provide increased security by preventing relays from tripping for stable power swings. Preventing the tripping of transmission lines during these types of disturbances increases the reliability of the BES. Requirement R2 should be removed because it has been interpreted to restrict the setting of OOSB elements making compliance with PRC-026 more difficult. Attachment A exclusion 2.3 should also be removed. This exclusion is no longer needed and that exclusion has contributed to the confusion surrounding R2. Attachment A exclusion 2.3 has been			

¹ The term power swing blocking (PSB) is also used by industry to describe these elements

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interpreted as being in conflict with R2. Both R2 and Attachment A exclusion 2.3 are not needed in the Standard.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
The purpose of the proposed project provides a reliability-related benefit by eliminating PRC-023-4 Requirement R2. This will eliminate entities disabling their OOSB elements unnecessarily. It will remove an unnecessary exclusion (Attachment A – 2.3) for relays that no longer need an exclusion.
Project Scope (Define the parameters of the proposed project):
The scope includes: • Retire Requirement R2. • Remove Attachment A, Item 2.3 exclusion with regard to the use of protection systems during stable power swings. • Make comportsing changes to the standard as needed to address the retirement of Requirement R2 and to remove Attachment A, Item 2.3 exclusion. • Ensure that removing the Item 2.3 exclusion does not overlap or create a gap with intent of PRC-026 – Relay Performance During Stable Power Swings. • Making any administrative non-substantive corrections. • Modify the Supplemental Technical Reference Document, “Determination and Application of Practical Relaying Loadability Ratings Version 1”, referenced in PRC-023-4, as needed to address the retirements and removal. Specifically, the Out of Step Blocking section.
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 justification² 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 PRC-023 standard is about setting protective relays so they do not limit transmission loadability, meaning they do not trip unnecessarily during heavy loading conditions while still being capable of detecting all fault conditions.³ The intent of Requirement R2 is to ensure out-of-step blocking (OOSB) elements allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability. Requirement R2 is about ensuring OOSB elements allow blocked relay elements to trip reliably (i.e., if a three-phase fault occurs while OOSB is asserted) and not about ensuring protection systems do not limit transmission loadability. OOSB elements differentiate between power swings and three-phase faults. During a power swing, a OOSB element will typically block phase distance elements (i.e., Zone 1 & Zone 2 phase distance elements) from tripping. According to Requirement R2, a OOSB element must unblock the blocked phase distance elements for faults that occur

² 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.

³ PRC-023-4, 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.”

Requested information

during the loading conditions used to set the protective relay under Requirement R1. Also in the standard, Attachment A, Item 2.3 excludes protection systems intended for protection during stable power swings and is seen as contradictory with Requirement R2 because these protection systems are associated with the use of OOSB elements, whose primary purpose is to ensure phase distance elements don't trip during stable power swings.

The apparent intent of Requirement R2 is to ensure that OOSB elements don't pick up, time out, and block distance elements from tripping for three-phase faults during the loading conditions described in Requirement R1. The protection engineer must ensure reliable fault protection and has various tools in modern microprocessor based relays to ensure the dependable unblocking of tripping elements during faults. Applying the loadability criteria while ensuring reliable fault protection is already an underpinning of Requirement R1.⁴ For example, an engineer can apply the use of override timers⁵ that are available in modern microprocessor relays or can add such timers to existing electromechanical relay elements. An engineer can also use advanced microprocessor-based zero-setting OOSB algorithms. Applying the loadability criteria to relay settings under Requirement R1 somewhat meets the intent of Requirement R2 because Requirement R1 mandates not limiting transmission loadability while maintaining reliable protection of the Bulk Electric System for all fault conditions. Additionally, Requirement R2 restrictively dictates the boundary setting of the OOSB element that starts the OOSB timer which has the overall effect of reducing the slip rate for which the OOSB element will correctly block. This results in decreasing the security of the protection scheme and increasing the chance that a misoperation of a distance element will occur for power swings that are faster than the allowable slip rate. Requirement R2 also impacts the ability to comply with NERC Reliability Standard PRC-026 (Relay Performance During Stable Power Swings) in that it affects the application of OOSB relaying that is integral to the purpose of PRC-026, which is "[t]o ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions".

Attachment A, 2.3 was included for protection systems that intentionally trip during power swing disturbances, such as intentional islanding schemes. Florida was cited as an example of where these schemes were employed. Research has indicated that these schemes no longer exist and there is no need for a power swing tripping exclusion.

Requirement R2 was added to PRC-023 in version 2 after filing version 1 with FERC.⁶ FERC observed that Attachment A item 2 in PRC-023-1 was a requirement and that it needed to be included in the requirements section of a standard with the appropriate violation risk factors and violation severity levels.

⁴ PRC-023-4, "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."

⁵ OOSB relays with override timers will allow the OOSB blinder that starts the timer to be set beyond the loadability region prescribed by the standard. The OOSB relay would unblock after a predetermined delay should an unlikely three-phase fault occur.

⁶ See FERC Order 733 para 244 <https://www.ferc.gov/whats-new/comm-meet/2010/031810/E-5.pdf>

Requested information
The original SDT included the “warning” in Attachment A item 2, with regards to OOSB, in reference to the OOSB timer. Some OOSB schemes employ an outer and an inner impedance blinder with a timer that is used to determine the rate of change of apparent impedance to differentiate between a fault (fast change) and a swing (slow change). The timer starts timing when the impedance passes through (is less than) the outer blinder. If the impedance does not pass through the inner blinder (is less than), before the timer setting, the OOSB will declare a swing and block the phase distance elements from tripping. The SDT wanted to inform entities that they could experience loading conditions that would result in an impedance that was between the OOSB blinders for a long period of time that would result in the blocking of the phase tripping elements indefinitely. This condition could exist at any time regardless of a relay loadability requirement. Therefore, this should not be a requirement associated with PRC-023. It is good engineering practice to ensure your relays will operate properly for all conditions they are expected to experience. This should not be a requirement in a relay loadability Standard. OOSB elements are included in the Relay Performance During Stable Power Swings Standard PRC-026-1. PRC-026-1 already includes the language “while maintaining dependable fault detection” in regards to OOSB supervision. Attachment A item 2.3 excludes “Protection systems intended for protection during stable power swings”. This exclusion is referencing “Protection systems installed specifically to separate portions of the system that are experiencing stable power swings relative to each other in order to maintain desirable performance relative to voltage, frequency, and power oscillations”⁷. These Out of Step Tripping (OOST) protection systems are better addressed in the standard for power swings, PRC-026.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
Should reduce cost to Registered Entities by eliminating the compliance monitoring of a requirement that is addressed by another standard. Revising the exemption should not have a significant impact on cost.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (e.g. Dispersed Generation Resources):
Transmission facilities that use OOSB functionality and that experience significant oscillations (i.e., power swings) has the benefit of ensuring the system remains intact where separation of portions of the transmission system could occur due to power swings.
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 Owner, Generator Owner, and Distribution Provider

⁷ See Project 2010-13.1 Phase 1 of Relay Loadability: Transmission Draft 1 Relay Loadability Standard Consideration of Comments
https://www.nerc.com/pa/Stand/Project%202010131%20Phase%201%20of%20Relay%20Loadability%20Trans/Consider_Comments_1st_Draft_Relay_Loadability_Std_09Jan07.pdf

Requested information
Do you know of any consensus building activities ⁸ in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
N/A
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)?
PRC-026 – Relay Performance During Stable Power Swings (Note: Project 2015-09 – Establish and Communicate System Operating Limits is proposing modifications to PRC-026 due to revisions to the definition of System Operating Limit).
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.
N/A

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

⁸ 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	
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
N/A	

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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

Standard Authorization Request (SAR)

Complete and submit this form, with attachment(s) to the [NERC Help Desk](#). Upon entering the Captcha, please type in your contact information, and attach the SAR to your ticket. Once submitted, you will receive a confirmation number which you can use to track your request.

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:	Operational Data Exchange Simplification		
Date Submitted:	June 23, 2020		
SAR Requester			
Name:	Standards Efficiency Review Phase 2 Team (~~John Allen~~ <u>Michael Cruz-Montes</u>)		
Organization:	~~City Utilities of Springfield~~ <u>CenterPoint Energy</u>		
Telephone:	~~417-831-8972~~ <u>713-207-2132</u>	Email:	~~John.Allen@cityutilities.net~~ <u>michael.cruz-montes@centerpointenergy.com</u>

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?):

The proposed project will enhance the effective and efficient administration of operational data ~~exchange for the purpose of focusing operating personnel on~~ exchanges between Responsible Entities essential for safe, secure and reliable operations.

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

The primary purpose of this project is to simplify administrative burdens identified by the SER Phase 2 Team associated with the current IR0-010-~~23~~ and TOP-003-~~34~~ standards and limit unnecessary data retention requirements that do not contribute to BES reliability and resiliency. As written the standards may create a zero-defect expectation for each Registered Entity receiving a data specification to demonstrate perfect performance on every item in the data specification for an entire audit period. This can result in unnecessary administrative burdens for the Registered Entity to demonstrate compliance,

Requested information

including excessive data retention. If instead a risk-based approach was developed and performance was triggered upon an event or unresolved data conflicts between entities, then the purpose of the standards would be achieved in an effective and efficient manner.

Therefore, the industry would benefit from continuing the efforts of Project 2014-03 and further revising IRO-010-~~32~~ and TOP-003-~~43~~ to enhance the “data specification” approach to reduce the administrative burdens of excessive data retention, while ensuring Registered Entities with operational responsibilities continue, as under the current standards, to request and receive ~~any~~the data necessary to support the four tasks identified in IRO-010-~~32~~ and TOP-003-~~43~~ (and described in the Detailed Description section below), while protecting public disclosure of commercially sensitive information and providing a dispute resolution process. To preserve the “data specification” concept, flexibility for differences in operational environments and emerging technology must be maintained. Therefore, creating a minimum list of items to include in a data specification is not desired. However, more clarity regarding the scope of the four tasks identified in IRO-010-~~32~~ and TOP-003-~~34~~ would be beneficial and is desired. The scope of the data specification would then just reflect the information necessary to cover the scope of the applicable tasks identified in IRO-010-~~32~~ or TOP-003-~~43~~ for the individual Registered Entity. The SER Phase 2 team received some feedback from industry participants who believe the scope of a data specification would only contain routine real time operating data typically provided systematically from field devices via SCADA/ICCP. Therefore, it is also necessary to clarify for industry if it should contain other data/information and methods of transfer such as phone, instant messaging, internet-based systems, etc.

A secondary purpose of this project is to evaluate removing other data exchange requirements dispersed in other standards. The drafting team would need to evaluate those requirements after proposed changes to the IRO-010 and TOP-003 are developed to determine if they are within the scope of the four tasks and consequently within the scope of IRO-010 and TOP-003. This may require enhancing the standards to allow each Registered Entity with responsibilities to perform the tasks identified in IRO-010-~~23~~ and TOP-003-~~34~~ the ability to request and receive any information it needs from other Registered Entities to perform those tasks. The intent of the project is not to do away with specific requirements in other Reliability Standards under the assumption that the same data will be requested per a data exchange under IRO-010-3 and TOP-003-4; and the Standard Drafting Team should evaluate any potential reliability risk incurred by removing a perceived redundant requirement prior to recommending changes to requirements in other Reliability Standards.

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

The scope of the proposed project is to simplify the administrative burden with IRO-010-~~32~~, TOP-003-~~43~~ by developing risk-based compliance expectations and clarifying the four tasks identified in IRO-010-~~32~~ and TOP-003-~~43~~. The proposed project may require revisions to IRO-010-23, TOP-003-34 and associated definitions (especially Real-time monitoring and Balancing Authority analysis functions) as necessary to mitigate expectations of zero-defect compliance (e.g., setting thresholds to address telemetry availability), include provisions for dispute resolution, negotiating data exchanges where entities disagree on the necessity of data for reliability, and address confidentiality concerns. The proposed

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project will need to utilize any available industry resource necessary to maintain flexibility for various operational environments and technology. ~~The project will require revisions to IRO-010-2, TOP-003-3 and associated definitions (especially Real-time monitoring and Balancing Authority analysis functions) and (i.e., SCADA/ICCP, phone, instant messaging, internet-based systems, etc.).~~ The project may also require development of Implementation Guidance or other ERO guidance to simplify the administrative burden.

The proposed project may also require revisions to other standards as necessary to ~~clarify data use requirements or clarify expectations and~~ remove redundant data specification obligations contained in other Reliability Standards that are associated with the four reliability tasks identified in the Detailed Description below. The scope of the project should also include coordination with existing projects that have operational data exchange within their scope ~~including projects 2015-09 and 2019-06~~.

If necessary, the proposed project may also require revisions to address data and information exchanges and obligations between provider and requester that are facilitated through a third-party intermediary.

~~The proposed project may also require revisions to address the need for entities that serve as data pass through entities to recognize their role in the data and information from the provider to the requester.~~

~~If necessary, the The proposed project may also require revisions to address data and information exchanges and between obligations between provider and requester that are facilitated through a third-party intermediary.~~

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 justification¹ 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 project ~~will, at a minimum, may~~ require revisions to IRO-010-~~23~~, TOP-003-~~34~~ and associated definitions in the NERC Glossary (especially Real-time monitoring and Balancing Authority analysis functions) to clarify expectations for the “data specification” and associated tasks identified in IRO-010-~~23~~ and TOP-003-~~34~~. The revisions should continue to allow each Registered Entity with operational responsibilities to perform the tasks identified in IRO-010-~~23~~ and TOP-003-~~34~~ the ability to request and receive ~~anythe~~ information it needs to perform those tasks, while protecting public disclosure of commercially sensitive information ~~and providing a dispute resolution process for conflicts between~~

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.

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entities related to necessary data exchanges. The four tasks identified in IRO-010-~~23~~ and TOP-003-~~34~~ and associated standards are listed below.

- Operational Planning Analysis (IRO-008-2 and TOP-002-4)
- Real-time Assessments (IRO-008-2 and TOP-001-4)
- Real-time monitoring (IRO-002-5 and TOP-001-4)
- Balancing Authority analysis functions (BAL-001-2, BAL-002-3, BAL-003-1.1 and BAL-005-1)

This may necessitate revisions to the standards included above and any other standard or definition identified by the drafting team during the project as necessary to achieve the purpose of this project. The drafting team should also ~~coordinate with pre-qualified organizations to~~ ^[A1] develop Implementation Guidance and/or NERC staff to develop other ERO guidance to simplify the administrative burden as needed.

Once those activities are clarified, the drafting team should also evaluate and, if necessary, remove potentially redundant operational data exchange requirements dispersed in other standards including, but not limited to, the following:

- BAL-005-1 R2
- EOP-005-3 R13
- EOP-005-3 R14.2
- FAC-014-2 R5
- FAC-014-2 R6.1.
- IRO-008-2 R5
- IRO-008-2 R6
- IRO-017-1 R3
- TOP-001-~~54~~ R9
- TOP-001-~~54~~ R15
- VAR-002-4.1 R3
- VAR-002-4.1 R4

The project should also evaluate any other standard identified by the drafting team during the project as necessary to achieve the purpose of this project. The ~~drafting team~~ Standard Drafting Team should seek to identify opportunities to remove redundant requirements and, if necessary, retire requirements that are not needed for reliability; however, the Standard Drafting Team should not retire requirements that are not directly related to the four reliability tasks identified above. The evaluation at a minimum should consider the following questions:

- Is the purpose of the activity currently within the scope of one or more of the tasks and consequently IRO-010-~~32~~ and TOP-003-~~43~~? If so, then consider removing due to redundancy. If so, then remove as redundant.
- If minor modifications were made to IRO-010-~~32~~, TOP-003-~~43~~ and/or associated definitions (especially Real-time monitoring and Balancing Authority analysis functions), then would the

Requested information
activity be within the scope of those standards? If so, then <u>consider removing due to redundancy</u>~~revise and remove as redundant.~~ ~~Does the receiving Registered Entity have an obligation to use the information? If not so, then consider or recommend modification to existing identify the existing requirement or create a the need for new requirements while ensuring RC, BA, or TOP can acquire any needed information to perform the four reliability tasks. for them to use it. If not, then retire outright as unnecessary for reliability of the BES.~~ The drafting team should reference precedence from past projects to support this effort, including background materials developed during Project 2014-03 that describe the “data specification” concept including the petition to the FERC and the Project 2014-03 Mapping Document.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
unknown
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (e.g., Dispersed Generation Resources):
N/A
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):
All NERC Functional Entities are potentially impacted by the scope of this SAR. The recommendations are both technical and administrative in nature but meant to address inefficiencies within requirements for data collection. Therefore, the drafting team should consist of members who are familiar with both aspects.
Do you know of any consensus building activities² in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
The SER Phase 2 team hosted an industry webinar on February 22, 2019 presenting six efficiency concepts, including consolidating and simplifying information and data requirements. The presentation was followed up by an industry survey to assess support for the concepts. This concept received the second highest support from industry. In addition, an informal survey was conducted on the content of this SAR to assess industry support. The feedback from industry and SER Phase 2 team responses are located on the Standards Efficiency Review page.
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)?
~~Yes, Projects 2015-09 and 2019-06.~~

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

The Standard Drafting team should coordinate with existing projects that have operational data exchange within their scope.

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.

Yes, Implementation Guidance and/or other ERO guidance could assist with simplifying the administrative burden for the interim period while this project is being administered.

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
<i>e.g.</i> , NPCC	

For Use by NERC Only

SAR Status Tracking (Check off as appropriate).

☐ Draft SAR reviewed by NERC Staff	☐ Final SAR endorsed by the SC
☐ Draft SAR presented to SC for acceptance	☐ SAR assigned a Standards Project by NERC
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Version History

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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
3	February 22, 2019	Standards Information Staff	Added instructions to submit via Help Desk

Standard Authorization Request (SAR)

Complete and submit this form, with attachment(s) to the [NERC Help Desk](#). Upon entering the Captcha, please type in your contact information, and attach the SAR to your ticket. Once submitted, you will receive a confirmation number which you can use to track your request.

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:	Extreme Cold Weather Grid Operations, Preparedness, and Coordination		
Date Submitted:	10/6/2021		
SAR Requester			
Name:	Steven Noess & Kiel Lyons		
Organization:	NERC, as members of the 2021 FERC, NERC, Regional Entity Joint Inquiry into 2021 Cold Weather Grid Operations		
Telephone:	(404) 446-9691 (404) 446-9665	Email:	Steven.Noess@nerc.net Kiel.Lyons@nerc.net
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?):			
To enhance reliability of the BES through improved operations, preparedness, and coordination during extreme weather, as described by the Federal Energy Regulatory Commission (FERC), NERC, and Regional Entity Joint Staff Inquiry into the February 2021 Cold Weather Grid Operations. See https://www.ferc.gov/media/february-2021-cold-weather-grid-operations-preliminary-findings-and-recommendations-full. From February 8 through 20, 2021, extreme cold weather and precipitation caused large numbers of generating units to experience outages, derates or failures to start, resulting in energy and transmission emergencies (referred to as "the Event"). The total Event firm load shed was the largest controlled firm load shed event in U.S. history and was the third largest in quantity of outaged megawatts (MW) of load after the August 2003 northeast blackout and the August 1996 west coast blackout. The Event was most			

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severe from February 15 through February 18, 2021, and it contributed to power outages affecting millions of electricity customers throughout the regions of ERCOT, SPP and MISO South. Extreme cold weather is a common occurrence, and it has jeopardized the reliable operation of the bulk-power system. The February 2021 event is the fourth in the past 10 years which jeopardized bulk-power system reliability. In February 2011, an arctic cold front impacted the southwest U.S. and resulted in numerous generation outages, natural gas facility outages and emergency power grid conditions with need for firm customer load shed. In January 2014, a polar vortex affected Texas, central and eastern U.S. This 2014 event also triggered many generation outages, natural gas availability issues and resulted in emergency conditions including voluntary load shed. And in January 2018, an arctic high-pressure system and below average temperatures in the south-central U.S. resulted in many generation outages and the need for voluntary load shed emergency measures.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
The new or revised reliability standards are intended to address reliability-related findings from the 2021 joint inquiry, which in many cases are consistent with prior reports' recommendations.
Project Scope (Define the parameters of the proposed project):
The Project Scope will address nine recommendations for new or enhanced NERC Reliability Standards proposed by the Federal Energy Regulatory Commission (FERC), NERC, and Regional Entity Joint Staff Inquiry into the February 2021 Cold Weather Grid Operations. The preliminary findings and recommendations of that joint inquiry were presented at the September 23, 2021, (FERC) Open Commission Meeting. Considering the topic areas, the submitters contemplate that the Standards Committee may convene one or more standard drafting teams to address collectively the recommendations in the joint inquiry report. The drafting team(s) should also consider the final report of the joint inquiry when it is released in late 2021, as it will contain additional context and analysis that will build upon the preliminary findings and recommendations. While the inquiry team does not anticipate material changes to the Reliability Standards Recommendations or basis for them provided in the preliminary presentation, the final SAR should reflect the final recommendations in the joint inquiry report.

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 justification¹ 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):

Technical justification is found within the work of the FERC, NERC, Regional Entity Joint Staff Inquiry. The proposed deliverable is new or revised Reliability Standards to enhance reliability during extreme cold weather.

The specific recommendations from the inquiry team have recommended “implementation timeframes,” which means in this context that the new and/or revised Reliability Standards that address the recommendation have been completed through the NERC Reliability Standards Development Process and are proposed (filed) for approval within the timeframes listed within the recommendations. For these recommendations, “Implementation Timeframe” means that the proposed Reliability Standards are complete and filed by November 1, 2022, for the Winter 2022/2023 timeframes and by November 1, 2023 for the Winter 2023/2024 timeframes. Each Reliability Standards recommendation below is accompanied by one of those two implementation timeframes.

There are nine recommendations each of which is designed to support the reliable operation of the bulk power system during cold weather conditions and/or stressed system conditions, with associated timeframes as described above:

1. Generator Owners are to identify and protect cold-weather-critical components and systems for each generating unit. Cold-weather-critical components and systems are those which are susceptible to freezing or otherwise failing due to cold weather, and which could cause the unit to trip, derate, or fail to start. **(Implementation Timeframe before Winter 2023/2024).**
2. Generator Owners are to design new or retrofit existing generating units to operate to a specified ambient temperature and weather conditions (e.g., wind, freezing precipitation). The specified ambient temperature and weather conditions should be based on available extreme temperature and weather data for the generating unit’s location, and account for the effects of precipitation and accelerated cooling effect of wind. **(Implementation Timeframe before Winter 2023/2024).**
3. Generator Owners and Generator Operators are to conduct annual unit-specific cold weather preparedness plan training. **(Implementation Timeframe before Winter 2022/2023).**
4. Generator Owners that experience outages, failures to start, or derates due to freezing are to review the generating unit’s outage, failure to start, or derate and develop and implement a corrective action plan for the identified equipment, and evaluate whether the plan applies to

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.

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similar equipment for its other generating units. **(Implementation Timeframe before Winter 2022/2023).**

5. The Reliability Standards should be revised to provide greater specificity about the relative roles of the Generator Owners, Generator Operators and Balancing Authorities in determining the generating unit capacity that can be relied upon during “local forecasted cold weather,” which is language from the revised Reliability Standard TOP-003-5, R2.3.
 - Each Generator Owner/Generator Operator should be required to provide the Balancing Authority with the percentage of the total generating unit capacity that the Generator Owner/Generator Operator reasonably believes the Balancing Authority can rely upon during the “local forecasted cold weather,” including reliability risks related to natural gas fuel contracts.
 - Each Balancing Authority should be required to use the data provided by the Generator Owner/Generator Operator, combined with its evaluation, based on experience, to calculate the percentage of each individual generating unit’s total capacity that it can rely upon during the “local forecasted cold weather,” and share its calculation with the Reliability Coordinator. Each Balancing Authority should be required to use that calculation of the percentage of total generating capacity that it can rely upon to “prepare its analysis functions and Real-time monitoring,” and to “manag[e] generating resources in its Balancing Authority Area to address . . . fuel supply and inventory concerns” as part of its Capacity and Energy Emergency Operating Plans.**(Implementation Timeframe before Winter 2022/2023).**
6. In EOP-011-2, R7.3.2, Generator Owners are to account for the effects of precipitation and accelerated cooling effect of wind when providing temperature data. **(Implementation Timeframe before Winter 2022/2023).**
7. To protect critical natural gas infrastructure from manual and automatic load shedding in order to avoid adversely affecting bulk-power system reliability, Balancing Authorities’ and Transmission Operators’ (TOPs) provisions for operator-controlled manual load shedding are to include processes for identifying and protecting critical natural gas infrastructure loads in their respective areas from firm load shed. Critical natural gas infrastructure loads are natural gas production, processing and intrastate and interstate pipeline facility loads which, if de-energized, could adversely affect the provision of natural gas to bulk-power system natural gas-fired generation. **(Implementation Timeframe before Winter 2023/2024).**
8. Balancing Authorities’ operating plans (for contingency reserves and to mitigate capacity and energy emergencies) are to prohibit use of critical natural gas infrastructure loads for demand response. **(Implementation Timeframe before Winter 2022/2023).**
9. In minimizing the overlap of manual and automatic load shed, the load shed procedures of Transmission Operators, Transmission Owners (TOs) and Distribution Providers (DPs) should separate the circuits that will be used for manual load shed from circuits used for underfrequency load shed (UFLS), undervoltage load shed (UVLS) or serving critical load. UFLS/UVLS circuits should only be used for manual load shed as a last resort and for UFLS

Requested information
circuits, should start with the final stage (lowest frequency). (Implementation Timeframe before Winter 2023/2024).
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
Unknown.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (e.g., Dispersed Generation Resources):
The BES facilities impacted by this proposed project will all have unique characteristics including fuel type, location, design, construction, etc. These unique characteristics need to be addressed during drafting to achieve the intended enhancements to reliability.
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):
Reliability Coordinator, Balancing Authority, Transmission Operator, Transmission Owner, Distribution Provider, Generator Operator, and 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.
The FERC, NERC, Regional Entity Joint Staff Inquiry into the 2021 Cold Weather Grid Operations was publicly noticed by both FERC and NERC.
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 proposed Reliability Standards are intended to build upon the requirements in EOP-011-2, IRO-010-4, and TOP-003-5 that were developed by Project 2019-06, and which for U.S. entities, were approved by FERC in August 2021. Additionally, several recommendations build on existing Standards related to load shedding and the development and implementation of UFLS and UVLS programs (e.g. EOP-011-2, PRC-006-5, and PRC-010-2). These Standards should be reviewed to ensure any conflicts or overlap with current requirements are mitigated.
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.
There have been several recommendations and guidelines that have developed over the prior noted events, but the events since illustrate that they are not as widely adopted as necessary to prevent reoccurrence.

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 Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

Reliability Principles	
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☒	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☒	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

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

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
e.g., NPCC	

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SAR Status Tracking (Check off as appropriate).			
☐	Draft SAR reviewed by NERC Staff	☐	Final SAR endorsed by the SC
☐	Draft SAR presented to SC for acceptance	☐	SAR assigned a Standards Project by NERC

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Standard Authorization Request (SAR)

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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.

Requested information			
SAR Title:		FAC-008 Facility Ratings	
Date Submitted:		07-14-2021	
SAR Requester			
Name:		Ryan Walter	
Organization:		Tri-State Generation and Transmission Association, Inc.	
Telephone:		303-254-3722	Email: rwalter@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?):			
Produce Generator Owner Facility Ratings that accurately reflect the real power capability of the facility and are therefore useful for reliability-related activities (such as in contingency analysis, SOL determination, etc.).			
Additionally, provide clarification around the phrase "jointly owned" and the level of individual component ratings that are required to be shared with the other entity. This will ensure clear expectations are set such that there are no gaps or conflicts between interconnecting entities.			
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):			
As currently written, the FAC-008 Reliability Standard and associated defined terms "Facility" and "Element" have been interpreted by some to mean that only electrical components may be considered when developing Generator Facility Ratings under R1. This could lead to planning and operational entities being provided Generator Facility Ratings that are higher than the actual output the plant is capable of, which could be detrimental to reliability during actual system emergencies. Explicitly			

Requested information

allowing the inclusion of mechanical elements in the development of Facility Ratings will ensure Generators are rated to their most limiting element.

Further, the FAC-008-3 non-formal use of the term “jointly owned” is ambiguous when compared with the industry legacy use of “jointly owned” as a purely financial and contractual obligation. This lack of clarity of intent of the standard could cause risk of facility rating gaps, misunderstanding of rating overlap requirements or gaps in facility rating coordination that could be resolved by clearly defining the technical expectations of the term “jointly owned”.

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

The scope of this project would be to modify FAC-008 and any associated defined terms to address the following:

1. Clarify the term “jointly owned”, and what information is required to be shared with neighboring entities.
2. Permit inclusion of non-electrical equipment in the determination of GO Facility Ratings (R1).

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 justification¹ 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):

Requirement R1 of the FAC-008 Standard will be modified to allow Generator Owners the flexibility to include all applicable equipment at their facilities when determining their Facility Ratings. As currently written, some have interpreted requirement R1 to restrict Facility Ratings to only include electrical components. Generation facilities are often mechanically restricted by the performance capabilities of the turbines installed. By not allowing non-electrical equipment to be included, the GO may be developing and sharing Facility Ratings that are higher than the facility is actually capable. One possible solution to remedy this in the requirement is to add language permitting the inclusion of mechanical limitations, so long as the most limiting electrical component is not exceeded.

Generator Facility Ratings must be accurate to establish maximum capabilities for RC, TOP, and BA network models, resource adequacy studies, operational and contingency studies, outage reporting, and emergency response, as is reflected in FERC Order Approving Reliability Standard FAC-008-3 (Docket RD11-10-000), paragraph 10, “NERC states that the standard drafting team interpreted this directive to allow reliability entities to take rating information and prepare operating plans or planning assessments prior to real-time, which could allow for better situational awareness and improved reliability of the bulk electric system.”

¹ The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.

Requested information

The objectives of this SAR could be addressed in various ways. Here are a few ideas:

1. Alter the language within FAC-008, R1 to explicitly allow the inclusion of non-electrical components in Generator Facility Ratings documentation.
2. Generate a new NERC Defined term “Generation Facility”- This term would include the current NERC Glossary Term for “Facility”, but amend that definition to include the mechanical components of the generating plants.
 - a. R1 would then need to be modified to include this new definition where it currently utilizes the current definition of Facility.
3. Alter/expand the current definition of “Facility” to include components beyond “electrical components” as currently stated.
4. For “jointly owned” facilities, the following are potential solutions:
 - a. Add the term “electrically joined facilities” to the TO requirements, as it has been done in PRC-027-1. Here is an example:
“R3. Each Transmission Owner shall have a documented methodology for determining Facility Ratings (Facility Ratings methodology) of its solely owned, jointly owned, and electrically joined Facilities (except for those generating unit Facilities addressed in R1 and R2) that contains all of the following:”
 - b. Better define what “jointly owned” means by adding an applicable Facilities section, or a Standard Only Definition section, to the standard. For instance, the new Section could read:
Jointly Owned Facilities- a set of Element(s) at a single physical location where more than one Registered Entities are financially responsible for the repair, replacement, or installation of equipment at that site.
 - c. Better define what “jointly owned” means by creating implementation compliance guidance similar to the “CIP-002-5.1a R1 Shared Ownership of BES Facilities (CIPC)” implementation guidance.

Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):

Cost impacts for these changes should be minimal.

Entities would potentially need to reevaluate Generator Facility Ratings and associated Facility Rating documentation to include mechanical limitations.

Depending upon an entity’s current state and understanding of “jointly owned”, as it pertains to Transmission Facilities, additional resources could be required to perform facility ratings calculations and methodology changes consistent with the determined language from item 4 above.

Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (e.g., Dispersed Generation Resources):

Requested information
Generators, unlike the Transmission system of the electric grid, can be limited by both electrical and mechanical components. To correctly plan and operate the Bulk Electric System, Planning and Transmission Operations personnel need to be apprised of a generator's actual limitations regardless of limiting factor.
Coordination of Facility Ratings for formally defined "jointly owned" or "electrically joined" equipment could take time and require new coordination efforts between adjacent entities.
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 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)?
FAC-008-5, FAC-008-3 If any of the defined terms are modified, all other standards that utilize those terms will need to be assessed for compatibility.
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.
An ERO Practice Guide, Compliance Guidance or Interpretation could be helpful to address these issues.

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.
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² Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

Reliability Principles

☐	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
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Identified Existing or Potential Regional or Interconnection Variances

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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
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%			

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
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	Proect 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		

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
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 10/7/11		
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	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
		https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)							
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		

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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: %			

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
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.]		The majority of RSC member 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%			
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		

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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	
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	

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455	Project 2007-06	Project 2007-06 - System Protection Coordination - PRC-027-1	Additional Ballot	12/9/2013	12/31/2013	Quorum: 76.60% Approval: 65.71%	No Consensus 12/27/13	Affirmative	
456	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-033-1	Additional Ballot	1/10/2014	1/21/2014	Quorum: 76.92% Approval: 81.41%	Support 8/31/13	Affirmative	
457	Project 2010-01	Project 2010-01 - Training - PER-005-2	Additional Ballot	1/8/2014	1/22/2014	Quorum: 7912% Approval: 74.63%	Support 11/11/13	Affirmative	
458	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-004-3	Additional Ballot	1/10/2014	1/22/2014	Quorum: 75.22% Approval: 81.19%	Support 11/5/13	Affirmative	
459	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-010-2	Additional Ballot	1/10/2014	1/22/2014	Quorum: 75.22% Approval: 90.23%	Support 11/5/13	Affirmative	
460	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - Definition	Additional Ballot	1/16/2014	1/29/2014	Quorum: 76.12% Approval: 92.17%	Support 11/5/13	Affirmative	
461	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-002-4	Additional Ballot	1/22/2014	1/31/2014	Quorum: 76.03% Approval: 71.86%	No Consensus 11/1/13	Affirmative	Ballot Period Extended to 2/4/14
462	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-004-3	Final Ballot	1/27/2014	2/5/2014	Quorum: 83.88% Approval: 83.44%	Support 11/5/13	Affirmative	
463	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-010-2	Final Ballot	1/27/2014	2/5/2014	Quorum: 83.58% Approval: 91.51%	Support 11/5/13	Affirmative	
464	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-033-1	Final Ballot	1/27/2014	2/5/2014	Quorum: 82.49% Approval: 82.45%	Support 8/31/13	Affirmative	
465	Project 2010-01	Project 2010-01 - Training - PER-005-2	Final Ballot	1/27/2014	2/5/2014	Quorum: 84.02% Approval: 77.06%	Support 11/11/13	Affirmative	
466	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - Definition	Final Ballot	1/31/2014	2/10/2014	Quorum: 81.79% Approval: 90.12%	Support 11/5/13	Affirmative	
467	Project 2010-05.1	Project 2010-05.1 –Protection Systems: Phase 1 (Misoperations): PRC-004-3	Additional Ballot	2/21/2014	3/3/2014	Quorum: 75.06% Approval: 62.63%	Support 9/5/12	Affirmative	Ballot Period Extended to 3/11/14
468	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-002-4	Final Ballot	3/28/2014	4/7/2014	Quorum: 78.21% Approval: 77.62%	Support 3/28/14	Affirmative	
469	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	Additional Ballot	4/1/2014	4/10/2014	Quorum: 76.92% Approval: 83.40%	Support 8/31/13	Affirmative	
470	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-002-3	Additional Ballot	4/4/2014	4/14/2014	Quorum: 78.03% Approval: 82.40%		--	
471	Project 2014-04	Project 2014-04 Physical Security - CIP-014-1	Initial Ballot	4/20/2014	4/24/2014	Quorum: 88.60% Approval: 82.07%	Support 4/23/14	Abstain	
472	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	Final Ballot	4/25/2014	5/5/2014	Quorum: 80.37% Approval: 90.00%	Support--4/25/14	Affirmative	
473	Project 2013-04	Project 2013-04 - Voltage and Reactive Control - VAR-001-4, VAR-002-3	Final Ballot	4/23/2014	5/5/2014	Quorum: 83.84% Approval: 88.26%	Support--4/10/14	Affirmative	
474	Project 2014-04	Project 2014-04 - Physical Security - CIP-014-1	Final Ballot	5/1/2014	5/5/2014	Quorum: 92.53% Approval: 85.61%	Support--4/23/14	Abstain	
475	Project 2010-02	Project 2010-02 - Connecting Facilities to the Grid - FAC-001-2 and FAC-002-2	Initial Ballot	5/6/2014	5/15/2014	Quorum: 85.79%/79.08% Approval: 86.28%/78.81%	No Consensus--5/15/14	Reject	
476	Project 2012-13	Project 2012-13 - NUC - Nuclear Plant Interface Coordination	Initial Ballot	5/13/2014	5/22/2014	Quorum: 80.60% Approval: 97.36%	Support--5/20/14	Affirmative	
477	Project 2007-17.3	Project 2007-17.3 - Protection System Maintenance and Testing - Phase 3 (Sudden Pressure Relays) - PRC-005-X	Initial Ballot	5/23/2014	6/2/2014	Quorum: 85.42% Approval: 47.89%	Support	Affirmative	
478	Project 2010-13.3	Project 2010-13.3 - Phase 3 of Relay Loadability: Stable Power Swings	Initial Ballot	5/30/2014	6/9/2014	Quorum: 79.06% Approval: 17.02%	Does not Support--6/6/14	Negative	
475	Project 2010-02	Project 2010-02 - Connecting Facilities to the Grid - FAC-001-2 and FAC-002-2	Final Ballot	6/12/2014	6/23/2014	Quorum: 88.78%/86.72% 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.
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 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 Pick HTML Content 1	Final Ballot	7/7/2014	7/16/2014	Quorum: 80.73%/80.49%/80.00%/80.24%/80.24%/80.49%/80.24%/78.29%	CIP-003 No CIP-004 Yes CIP-006 Yes CIP-007 Yes CIP-008 Yes		

Last RSC Meeting

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483	Project 2014-02	http://www.nerc.com/pa/Stand/Pages/Project-2014-XX-Critical-Infrastructure-Protection-Version-5-Revisions.aspx	Final Ballot	7/7/2014	7/10/2014	Approval: 35.67%/80.76%/76.24 %/78.41%/85.32%/49.42%/82.55%/78.58%	CIP-005 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	(Sudden Pressure Relays) - PRC-005-X	Additional Ballot	9/3/2014	9/12/2014	Quorum: 84.33% Approval: 76.03%	Support--9/4/14	Affirmative	
492	Project 2014-03	Project 2014-03 - Revisions to TOP/IRO Reliability Standards	Additional Ballot	9/10/2014	9/19/2014	Quorum: 85.75%/84.96%/84.96 %/85.22%/84.96%/85.22%/85.49%/85.22%/86.28%/83.11%/83.91 % Approval: 76.12%/74.23%/75.67 %/85.49%/75.96%/78.67%/48.73%/78.87%/87.03%/93.34%/90.13 %	TOP-001-3: Negative TOP-002-4: Affirmative TOP-003-3: Affirmative IRO-001-4: No consensus however the majority indicated an Affirmative vote IRO-002-4: Negative IRO-008-2: No consensus, a majority indicated a Negative and the others indicated abstention IRO-010-2: Affirmative IRO-014-3: Negative IRO-017-1: Affirmative Implementation Plan and Definitions: Affirmative 9/18/14		
493	Project 2010-14.1	Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves	Additional Ballot	9/23/2014	10/2/2014	Quorum: 79.94% Approval: 46.73%	Negative--10/1/14		
494	Project 2010-13.3	Project 2010-13.3 - Phase 3 of Relay Loadability: Stable Power Swings	Additional Ballot	9/26/2014	10/6/2014	Quorum: 79.01% Approval: 53.02%	Affirmative--10/1/14		
495	Project 2012-13	Project 2008-02 Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS)	Additional Ballot	9/29/2014	10/8/2014	Quorum: 83.24%/84.82% Approval: 80.69%/84.05%	Affirmative--10/7/14	Affirmative	
496	Project 2012-13	Project 2013-03 Geomagnetic Disturbance Mitigation	Additional Ballot	10/1/2014	10/10/2014	Quorum: 82.93% Approval: 57.95%	Affirmative--10/7/14		
497	Project 2010-05.2	Project 2010-05.2 -- Special Protection Systems (Phase 2 of Protection Systems)	Additional Ballot	10/3/2014	10/14/2014	Quorum: 80.54% Approval: 75.79% Approval:	Affirmative--10/7/14		
498	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Additional Ballot	10/7/2014	10/16/2014	Quorum: 81.91%/82.12% Approval: 94.92%/94.37%	Affirmative--10/14/14		
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 %/84.49%/84.77%	CIP-003-6 no consensus CIP-010-2 no consensus New Definitions-Affirmative	CIP-003-6 and	

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: 93.21%/68.09%/74.25 %/79.91%/85.68%/89. 01%/91.79%/81.34%/ 96.63%/96.63%/95.52 %/85.93%/98.13%	Updated Definitions-Affirmative Implementation Plan-Affirmative Version X Materials-Affirmative Non-binding polls-Affirmative	CIP-010-2 Affirmative	
500	Project 2009-03	Project 2009-03 Emergency Operations	Additional Ballot	10/10/2014	10/20/2014	Quorum: 80.93% Approval: 70.41%	Affirmative--10/17/14		
501	Project 2014-03	2014-03 - Revisions to TOP and IRO Standards (IRO-001-4, IRO-002-4, IRO-010-2, two Definitions, and Implementation Plan)	Final Ballot	10/10/2014	10/20/2014	Quorum: 90/77%/89.97%/89.97 %/88.39%/88.39% Approval: 82.64%/85.96%/86.22 %/94.07%/91.84%	Affirmative--10/17/14		
502	Project 2014-03	2014-03 - Revisions to TOP and IRO Standards (TOP-002-4, TOP-003-3, IRO-008-2, IRO-014-3, and IRO-017-1)	Final Ballot	10/10/2014	10/20/2014	Quorum: 89.71%/88.39%/89.71 %/89.71%/89.97% 84.76%/86.55%/83.73 %/89.88%/82.58%	Affirmative--10/17/14		
503	Project 2007-11	Project 2007-11 Disturbance Monitoring	Additional Ballot	10/10/2014	10/21/2014	Quorum: 77.69% Approval: 71.38%	Affirmative--10/17/14		
504	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Additional Ballot	10/10/2014	10/22/2014	Quorum: 85.13%/83.29% Approval: 94.75%/93.98%	Affirmative--10/20/14		
505	Project 2014-03	Project 2007-17.3 (PRC-005-X) Protection System Maintenance and Testing - Phase 3 (Sudden Pressure Relays)	Final Ballot	10/20/2014	10/29/2014	Quorum: 88.25% Approval: 74.14%	Affirmative--10/28/14		
506	Project 2014-03	Project 2008-02 Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS)	Final Ballot	10/28/2014	11/6/2014	Quorum: 87.53% Approval: 83.12%	Affirmative--10/31/14		
507	Project 2007-11	Project 2007-11 Disturbance Monitoring	Final Ballot	10/28/2014	11/6/2014	Quorum: 81.89% Approval: 68.51%	Affirmative--10/31/14		
508	Project 2007-11	Project 2010-05.2 Phase 2 of Special Protection Systems	Final Ballot	10/28/2014	11/6/2014	Quorum: 85.41% Approval: 73.33%	Negative--10/14/14		
509	Project 2007-11	Project 2009-03 Emergency Operations	Final Ballot	10/28/2014	11/6/2014	Quorum: 87.19% Approval: 73.20%	Affirmative--10/17/14		
510	Project 2007-11	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Final Ballot	10/28/2014	11/6/2014	Quorum: 89.49%/87.66%/87.08 % Approval: 92.91%/92.15%/95.62 %	Affirmative--10/20/14		
511	Project 2014-03	Project 2014-02 Critical Infrastructure Protection Standards Version 5 Revisions	Final Ballot	10/28/2014	11/6/2014	Quorum: 87.56%/87.32%87.07 %/87.56%/87.80%87. 56%86.59% Approval: 83.84%/95.34%/86.00 %/95.35%91.17%/83. 88%/95.40%/92.76%	CIP-003-6 no consensus CIP-010-2 no consensus New Definitions-Affirmative Updated Definitions-Affirmative Implementation Plan-Affirmative Version X Materials-Affirmative Non-binding polls-Affirmative		
512	Project 2014-03	2014-03 - Revisions to TOP and IRO Standards	Additional Ballot	11/4/2014	11/10/2014	Quorum: 78.36% Approval: 60.21%	Affirmative--11/4/14		
513	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation	Additional Ballot	11/12/2014	11/21/2014	Quorum: 79.73% Approval: 77.29%	Affirmative--11/21/14		
514	Project 2014-03	Project 2010-13.3 Phase 3 of Relay Loadability: Stable Power Swings	Additional Ballot	11/14/2014	11/24/2014	Quorum: 79.83% Approval: 67.39%	Affirmative--10/1/14		
515	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation	Final Ballot	12/5/2014	12/16/2014	Quorum: 84.27% Approval: 78.05%	Affirmative--12/12/14		
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%	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		

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
						Approval: 81.92%/98.89%/98.86 %/88.13%/98.89%/86. 02%/89.63%/97.21%	CIP-007-7 Binding and non-binding polls –Affirmative CIP-007-7 Binding and non-binding polls –Affirmative CIP-011-7 Binding and non-binding polls –Affirmative CIP Implementation Plan- Affirmative 1/8/2015		
520	Project 2014-03	2014-03 - Revisions to TOP and IRO Standards - TOP-001-3	Final Ballots	1/15/2015	1/21/2015	Quorum: 84.70% Approval: 72.69%	Affirmative--1/6/15		
521	Project 2014-01	2014-01 - Standards Applicability for Dispersed Generation Resources - PRC-005-5	Initial Ballots	1/12/2015	1/22/2015	Quorum: 77.93% Approval: 93.74%	Affirmative--1/22/15		
522	Project 2014-01	2014-01 - Standards Applicability for Dispersed Generation Resources - PRC-001-1.1(ii), PRC-019-2, and PRC-024-2	Final Ballots	1/13/2015	1/22/2015	Quorum: 89.27%/89.30%/89.52 % Approval: 93.99%/94.03%/95.82 %	Affirmative--1/22/15		
523	Project 2014-02	2014-02 - Critical Infrastructure Protection Standards Version 5 Revisions CIP-003-7, CIP-004-7, CIP-010-3, and CIP-011-3	Final Ballot	1/23/2015	2/2/2015	Quorum: 84.15%/84.39%/84.15 %/84.39%/84.39%/83. 90%/84.39%/83.66% Approval: 79.76%/98.94%/98.94 %/86.76%/98.93%/84. 07%/90.10%/97.32%	Affirmative--1/29/15		
524	Project 2014-01	2014-01 - Standards Applicability for Dispersed Generation Resources - PRC-005-5	Final Ballot	3/2/2015	3/11/2015	Quorum: 83.52% Approval: 98.03%	Affirmative--1/22/15		
525	Project 2010-14.1	Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves	Additional Ballot	3/6/2015	3/16/2015	Quorum: 77.29% Approval: 59.30%	Negative--3/13/2015		
526	Project 2008-02.2	Project 2008-02.2 Phase 2 of Undervoltage Load Shedding (UVLS): Misoperations	Initial Ballot	3/27/2015	4/7/2015	Quorum: 79.93% Approval: 84.31%	Affirmative--3/31/15		
527	Project 2014-04	Project 2014-04 Physical Security	Initial Ballot	3/31/2015	4/9/2015	Quorum: 88.33% Approval: 89.95%	Affirmative--3/31/15		
528	Project 2008-02.2	Project 2008-02.2 Phase 2 of Undervoltage Load Shedding (UVLS): Misoperations	Final Ballot	4/17/2015	4/27/2015	Quorum: 84.86% Approval: 89.63%	Affirmative--3/31/15		
529	Project 2014-04	Project 2014-04 Physical Security	Final Ballot	4/20/2015	4/29/2015	Quorum: 92.00% Approval: 92.35%	Affirmative--3/31/15		
530	Project 2007-06	Project 2007-06 System Protection Coordination	Additional Ballot	5/6/2015	5/15/2015	Quorum: 81.79% Approval: 39.63%	Negative--5//13/15		
531	Project 2015-06	2015-06 Interconnection Reliability Operations and Coordination	Initial Ballot	6/29/2015	7/8/2015	Quorum: 75.23%/84.00% Approval: 90.35%/97.50%	Affirmative--7/7/15		
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%%	Affirmative--7/7/15		

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						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%	Affirmative--8/17/15		
535	Project 2007-06	Project 2007-06 System Protection Coordination	Additional Ballot	9/2/2015	9/11/2015	Approval: 69.26%	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: 84.34%	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	Approval: 69.76%	Abstention--9/14/15		
538	Project 2015-04	2015-04 Alignment of Terms	Final Ballot	9/4/2015	9/14/2015	Quorum: 87.16%	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	Approval: 62.55%	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: 96.81%/97.53%/97.51%/97.48%/97.51%/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%	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	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%	Negative--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%	Affirmative--8/17/15		
543	Project 2010-05.3	Project 2007-06 System Protection Coordination	Final Ballot	10/5/2015	10/14/2015	Approval: 74.61%	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%	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	Approval: 90.01%	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%	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	Approval: 47.38%/48.00%	Affirmative--11/5/15		
548	Project 2015-07	Project 2015-07 Internal Communications Capabilities	Initial Ballot	11/6/2015	11/16/2015	Quorum: 84.40%	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	Approval: 98.17%	Affirmative--11/18/15		
550	Project 2010-07.1	Project 2010-07.1 Vegetation Management	Initial Ballot	12/7/2015	12/16/2015	Quorum: 83.18%	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	Approval: 57.29%	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: 85.38%	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	Approval: 82.56%	BAL-005--Negative--1/10/16 BAL-006--Affirmative--1/10/16		

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: 70.64%/75.54%/94.30%	BAL-000--Affirmative--1/10/16 FAC-003-1--Abstention--1/10/16		
553	Project 2010-05.3	Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities	Additional Ballot	1/15/2016	1/25/2016	Quorum: 82.88%/82.18% Approval: 72.13%/68.01%	Affirmative--1/25/16		
554	Project 2010-07.1	Project 2010-07.1 Vegetation Management	Final Ballot	1/29/2016	2/8/2016	Quorum:90.03% Approval: 96.18%	Affirmative--2/1/16		
552	Project 2010-14.2.1	Project 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls -- BAL-005 and BAL-006	Final Ballot	1/29/2016	2/8/2016	Quorum: 86.35%/86.98%/86.67% Approval: 72.06%/94.61%/80.15%	Affirmative--2/3/15		
551	Project 2010-05.3	Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities	Final Ballot	2/17/2016	2/26/2016	Quorum: 88.36%/87.79% Approval: 75.68%/73.87%	Affirmative--1/25/16		
552	Project 2010-05.3	Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS)	Additional Ballot	3/9/2016	3/18/2016	Quorum: 75.55% Approval: 78.87%	Affirmative--3/10/16		
553	Project 2007-06.2	Project 2007-06.2 Phase 2 of System Protection Coordination	Initial Ballot	4/15/2016	4/25/2016	Quorum: 83.39%/83.33% Approval: 80.57%/78..39%	Affirmative--4/20/16		
554	Project 2010-05.3	Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS)	Final Ballot	4/20/2016	4/29/2016	Quorum: 81.19%/87.15% 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%	Affirmative--11/30/16		

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: 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%	Affirmative--12/2/16		
						Approval: 74.30%/72.52%			
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%	Affirmative--12/1/16		
						Approval: 87.95%/83.03%			
570	Project 2015-08	Project 2015-08 Emergency Operations EOP-004-4	Additional Ballot	12/28/2016	1/6/2017	Quorum: 79.47%	Affirmative--1/4/17		
						Approval: 93.55%			
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%	Affirmative--1/4/17		
						Approval: 83.65%/80.56%			
572	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-003-7(i) Implementation Plan and 2 Definitions	Initial Ballot	1/16/2017	1/25/2017	Quorum: 77.81%/76.71%/77.26 %/76.71%	Affirmative--1/23/17		
						Approval: 81.30%/87.87%/86.75 %/86.47%			
573	Project 2016-03	Project 2016-03 Cyber Security Supply Chain Risk Management	Initial Ballot	2/24/2017	3/6/2017	Quorum: 87.13%	Abstain--3/2/17		
						Approval: 10.36%			
574	Project 2015-08	Project 2015-08 Emergency Operations EOP-004-4	Final Ballot	1/24/2017	2/2/2017	Quorum: 84.46%	Affirmative--1/4/17		
						Approval: 93.80%			
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%	Affirmative--1/23/17		
						Approval: 78.55%/86.00%/85.81 %/85.54%			
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 %	Affirmative--6/8/17		
						Approval: 89.84%/82.92%/88.64 %			
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 %	Affirmative--6/8/17		
						Approval: 88.79%/81.40%/84.19 %			
579	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation TPL-007-2	Initial Ballot	8/2/2017	8/11/2017	Quorum: 79.87%	Affirmative--8/3/17		
						Approval: 72.67%			
580	Project 2016-04	Project 2016-04 Modifications to PRC-025-1	Initial Ballot	8/29/2017	9/8/2017	Quorum: 80.45%	Affirmative--9/1/17		
						Approval: 78.79%			
581	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-012-1 Control Center Communication Networks	Initial Ballot	8/14/2017	9/12/2017	Quorum: 80.00%	Affirmative--9/1/17		
						Approval: 42.74%			
582	Project 2015-10	Project 2015-10 Single Points of Failure TPL-001	Initial Ballot	9/8/2017	10/23/2017	Quorum: 82.71%	Abstain--10/18/17		
						Approval: 30.50%			
583	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation TPL-007-2	Final Ballot	10/20/2017	10/30/2017	Quorum: 88.74%	Affirmative--8/3/17		
						Approval: 73.35%			
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%	Affirmative--10/30/17		
						Approval: 66.78%			
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	Affirmative--11/10/17		
						Approval: 58.12%/63.17%/56.55 %/76.40%/68.59%			
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%	Affirmative--12/4/17		
						Approval: 63.91%			
587	Project 2016-04	Project 2016-04 Modifications to PRC-025-1	Additional Ballot	10/30/2017	12/13/2017	Quorum: 81.73%	Affirmative--12/4/17		
						Approval: 88.25%			
588	Project 2016-04	Project 2016-04 Modifications to PRC-025-1	Final Ballot	1/9/2018	1/18/2018	Quorum: 82.69%	Affirmative--12/4/17		
						Approval: 89.46%			
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%	Affirmative--3/7/18		

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: 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		
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		

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
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% 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%	Affirmative--4/10/19 for all standards except three. 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%/9 7.75%/96.57%	Affirmative--4/10/19 for all standards except three.		
615	Project 2018-04	Project 2018-04 Modifications to PRC-024-2	Initial Ballot	5/22/2019	5/31/2019	Quorum: 88.08% Approval: 52.28%	Abstain--5/29/19		
616	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-002-6	Additional Ballot	6/3/2019	7/17/2019	Quorum: 85.40% Approval: 87.39%	Affirmative--7/15/19		
617	Project 2019-01	Project 2019-01 Modifications to TPL-007-3	Initial Ballot	8/30/2019	9/9/2019	Quorum: 91.44% Approval: 88.81%	Affirmative--9/5/19		
618	Project 2017-01	Project 2017-01 Modifications to BAL-003-1.1	Final Ballot	10/10/2019	10/24/2019	Quorum: 92.96% Approval: 1001%	Affirmative--1/14/19		
619	Project 2018-04	Project 2018-04 Modifications to PRC-024-2	Additional Ballot	10/25/2019	11/4/2019	Quorum: 81.88% Approval: 86.67%	Affirmative--11/4/19		
620	Project 2019-01	Project 2019-01 Modifications to TPL-007-3	Final Ballot	11/13/2019	11/22/2019	Quorum: 94.52% Approval: 78.95%	Affirmative--9/5/19		
621	Project 2017-07	Project 2017-07 Standards Alignment with Registration	Initial Ballot	12/3/2019	12/12/2019	Quorum: 88.76%/89.02%/89.02 %/88.98%/89.96%/89. 06%/88.72%/87.89% Approval: 99.69%/99.36%/99.69 %/99.69%/99.59%/99. 38%/99.69%/99.68%	Affirmative--12/12/19		
622	Project 2018-04	Project 2018-04 Modifications to PRC-024-2	Final Ballot	12/4/2019	12/13/2019	Quorum: 89.26% Approval: 82.47%	Affirmative--11/4/19		
623	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-002-6	Additional Ballot	11/1/2019	12/16/2019	Quorum: 81.89% Approval: 95.98%	Affirmative--12/12/19		
624	Technical Rationale for Reliability Standards	Technical Rationale for Reliability Standards	Non-binding Poll	12/9/2019	12/18/2019	Quorum: 85.46%/82.52%/82.83 %/82.35%/82.76%/86. 55%/81.77%/86.82%/ 82.76% Approval: 84.91%/88.89%/85.12 %/86.57%/86.57%/86. 79%/89.55%/88.75%/ 77.78%	Affirmative--12/12/19		

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
625	Project 2017-07	Project 2017-07 Standards Alignment with Registration	Final Ballot	1/14/2020	1/23/2020	Quorum: 89.53%/89.8%/89.8%/89.76%/90.83%/89.84%/89.88%/88.67% Approval: 99.69%/99.69%/99.69%/99.69%/99.69%/99.6%/99.38%/99.69%/99.69%	Affirmative--12/12/19		
626	Project 2019-02	Project 2019-02 BES Cyber System Information Access Management	Initial Ballot	1/24/2020	2/3/2020	Quorum: 92.09%/92.78%/91.58% Approval: 15.37%/13.04%/22.30%	Abstain--1/31/20		
627	Project 2019-03	Project 2019-03 Cyber Security Supply Chain Risks	Initial Ballot	1/27/2020	3/11/2020	Quorum: 88.37% Approval: 50.51%	Abstain--2/26/20		
628	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-002-6	Final Ballot	3/26/2020	4/6/2020	Quorum: 87.92% Approval: 96.28%	Affirmative--12/12/19		
629	Technical Rationale for Reliability Standards	Technical Rationale for Reliability Standards	Non-binding Poll	4/10/2020	4/20/2020	Quorum: 81.93%/82.24%/80.49%/82.17%/81.44%/81.78%/81.3%/81.92%/80.93%/81.73% Approval: 86.475/87.77%/87.12%/85.48%/85.7%/87.1%/86.93%/85.8%/76.9%/79.25%	Affirmative--4/17/20		
630	Project 2019-03	Project 2019-03 Cyber Security Supply Chain Risks	Additional Ballot	6/12/2020	6/22/2020	Quorum: 78.74% Approval: 34.44%	Abstain--2/26/20		
631	Project 2015-09	Project 2015-09 Establish and Communicate System Operating Limits	Initial/Additional Ballot	7/24/2020	8/26/2020	Quorum: 81.48%/81.73%/81.35%/81.15%/80.57%/80.98%/80.43%/80.67%/91.18%/91.48% Approval: 58.50%/88.32%/79.26%/86.98%/72.82%/88.78%/88.50%/89.16%/85.21%/81.17%	Affirmative--7/24/20		
632	Project 2019-02	Project 2019-02 BES Cyber System Information Access Management	Additional Ballot	9/11/2020	9/21/2020	Quorum: 84.98%/83.82%/82.84% Approval: 32.80%/23.06%/50.49%	Abstain--9/17/20		
633	Project 2019-03	Project 2019-03 Cyber Security Supply Chain Risks	Final Ballot	10/7/2020	10/16/2020	Quorum: 83.56% Approval: 76.76%	Abstain--2/26/20		
634	Project 2015-09	Project 2015-09 Establish and Communicate System Operating Limits	Additional Ballot	11/27/2020	12/7/2020	Quorum: 82.82%/82.41% Approval: 66.61%/89.79%	Affirmative--12/4/20		
635	Project 2018-03	Project 2018-03 Standards Efficiency Review Retirements	Initial Ballot	4/3/2019	4/12/2019	Quorum: 89.93%/86.61% Approval: 95.91%/100%	Affirmative--1/4/21		
636	Project 2018-03	Project 2018-03 Standards Efficiency Review Retirements	Final Ballot	1/19/2021	1/28//21	Quorum: 91.04% Approval: 95.96%	Affirmative--1/4/21		
637	Project 2019-06	Project 2019-06 Cold Weather	Initial Ballot	3/3/2021	3/12//21	Quorum: 89.71%/89.49%/89.81% Approval: 49.39%/66.22%/64.35%	Affirmative--3/3/21		
638	Project 2016-02	Project 2016-02 Modifications to CIP Standards Virtualization	Initial Ballot	3/12/2021	3/22/2021	Quorum: 90.26%/89.94%/89.87%/89.87%/89.87%/90.16%/89.87%/89.54%/89.87%/89.54% Approval: 95.96%	Abstain--3/17/21		

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						Approval: 38.87%/48.30%/51.17 %/26.30%/42.81%/42. 32%/52.87%/53.26%/ 32.43%/47.25%/51.23 %	Abstain--5/17/21		
639	Project 2015-09	Project 2015-09 Establish and Communicate System Operating Limits	Additional Ballot	2/19/2021	4/5/2021	Quorum: 80.67% Approval: 92.35%	Affirmative--3/31/21		
640	Project 2019-06	Project 2019-06 Cold Weather	Additional Ballot	4/2/2021	4/26//21	Quorum: 87.74%/86.58%/86.26 % Approval: 77.10%/85.42%/85.20 %	Affirmative--3/3/21		
641	Project 2015-09	Project 2015-09 Establish and Communicate System Operating Limits	Final Ballot	4/29/2021	5/10/2021	Quorum: 85.76%/83.44%/86.19 %/86.45%/85.67%/86. 19%/94.42%/94.00%/ 84.57% Approval: 82.83%/92.34%/93.75 %/94.17%/93.55%/94. 18%/89.59%/87.93%/ 93.01%	Affirmative--3/31/21		
642	Project 2015-09	Project 2015-09 Establish and Communicate System Operating Limits	Final Ballot	4/29/2021	5/10/2021	Quorum: 86.43% Approval: 76.93%	Affirmative--3/31/21		
632	Project 2019-02	Project 2019-02 BES Cyber System Information Access Management	Additional Ballot	3/25/2021	5/10/2021	Quorum: 84.31%/84.62%/83.64 % Approval: 83.75%/81.39%/92.51 %	Affirmative--4/30/21		
640	Project 2019-06	Project 2019-06 Cold Weather	Final Ballot	5/18/2021	5/27/2021	Quorum: 90.65%/89.46%/89.14 % Approval: 78.26%/87.30%/87.52 %	Affirmative--3/3/21		
641	Project 2020-04	Project 2020-04 Modifications to CIP-012	Initial Ballot	4/26/2021	6/9/2021	Quorum: 89.84%/88.97% Approval: 37.31%/68.75%	Abstain--6/7/21		
642	Project 2019-02	Project 2019-02 BES Cyber System Information Access Management	Final Ballot	6/2/2021	6/11/2021	Quorum: 86.50%/86.81%/85.87 % Approval: 85.80%/83%/94.17%	Affirmative--4/30/21		
643	Project 2016-02	Project 2016-02 Modifications to CIP Standards Virtualization	Additional Ballot	8/23/2021	9/1/2021	Quorum: 87.58%/87.58%/87.83 %/87.50%/87.50%/87. 50%/87.83%/87.83%/ 87.83%/87.83%/87.83 % Approval: 36.22%/41.55%/38.09 %/20.25%/42.19%/29. 40%/49.48%/49.73%/ 33.22%/40.16%/41.43 %	Abstain--8/25/21		
644	Project 2020-03	Project 2020-03 Supply Chain Low Impact Revisions	Initial Ballot	10/1/2021	10/11/2021	Quorum: 83.56%/83.81% Approval: 29.09%/28.50%	Abstain--10/7/21		
645	Project 2020-04	Project 2020-04 Modifications to CIP-012	Additional Ballot	1/14/2022	1/24/2022	Quorum: 87.46%/87.59% Approval: 34.64%/65.77%	Abstain--1/24/22		
646	Project 2020-05	Project 2020-05 Modifications to FAC-001 and FAC-002	Initial Ballot	1/21/2022	1/31/2022	Quorum: 94.07%/94.05% Approval: 85.19%/78.97%	Affirmative--1/31/22		

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	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
					(Sorted Oldest to Newest)				

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	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
					(Sorted Oldest to Newest)				

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	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
					(Sorted Oldest to Newest)				

RSC Meeting #22-1, Agenda Item 4.3: Comment History

(As of 2/1/2022)

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	<u>Yes 4/4/11</u>
14.	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting	EOP-004-2		3/9/11	4/8/11	<u>Yes 4/8/11</u>
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	<u>Yes 4/15/11</u>
17.	Project 2010-15	Project 2010-15 - Urgent Action Revisions to CIP-005-3 - CIP-005	CIP-005		3/29/11	4/28/11	<u>Yes 4/27/11</u>
18.	Project 2009-06	Project 2009-06 - Facility Ratings - FAC-008 and FAC-009	FAC-008-3		3/17/11	5/2/11	<u>Yes 5/2/11</u>
19.	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	PRC-005-2		4/13/11	5/12/11	<u>Yes 5/9/11</u>
20.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System	BES Definition		4/28/11	5/27/11	<u>Yes 5/27/11</u>
21.	Project 2006-02	Project 2006-02 - Assess Transmission and Future Needs	TPL-001-2		4/18/11	5/31/11	<u>Yes 5/31/11</u>
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	<u>Yes 6/9/11</u>
23.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System	BES Definition		5/11/11	6/10/11	<u>Yes 6/10/11</u>
24.	NERC RoP	Rules of Procedure Development Team: BES Definition Exception Process	BES Definition Exception Process		5/11/11	6/10/11	<u>Yes 6/10/11</u>

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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	<u>Yes 6/20/12</u>
90.	N/A	Adequate Level of Reliability Revised Definition and Associated Documents	Adequate Level of Reliability (ALR)		4/25/12	6/25/12	<u>Yes 6/25/12</u>
91.	N/A	Order 754 - Request for Data or Information	Data Request		5/11/12	6/25/12	<u>Yes 6/25/12</u>
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	<u>Yes 6/27/12</u>
93.	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	PRC-005-2		5/29/12	6/27/12	<u>Yes 6/27/12</u>
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	<u>Yes 7/3/12</u>
			BAL-002-2		6/4/12	7/3/12	<u>Yes 7/3/12</u>
			BAL-012-1		6/4/12	7/3/12	<u>Yes 7/3/12</u>
			BAL-013-1		6/4/12	7/3/12	<u>Yes 7/3/12</u>
95.	Project 2007-06	Project 2007-06 - System Protection Coordination	PRC-001 and PRC-027		5/21/12	7/5/12	<u>Yes 7/5/12</u>
96.	N/A	Cost Effective Analysis Process (CEAP) for NERC ERO Standards	CEAP		5/7/12	7/6/12	<u>Yes 7/6/12</u>
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	<u>Yes 7/6/12</u>
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	<u>Yes 7/9/12</u>

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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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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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 5/6/13
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	<u>Yes 8/23/13</u>
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	<u>Yes 8/23/13</u>
165.	Project 2012-05	Project 2012-05 ATC Revisions (MOD A) - MOD-001-2	MOD-001-2	Formal	7/11/13	8/26/13	<u>Yes 8/26/13</u>
166.	Project 2010-01	Project 2010-01 - Training - PER-005-2	PER-005-2	Formal	7/19/13	9/03/13	<u>Yes 9/3/13</u>
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	<u>Yes 9/3/13</u>
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	<u>Yes 9/4/13</u>
169.	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	MOD-031-1	Formal	7/22/13	9/04/13	<u>Yes 9/4/13</u>
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	<u>Yes 9/4/13</u>
171	Project 2012-13	Project 2012-13 - NUC Five-Year Review	NUC-001-2	5-year review	7/26/13	9/9/13	<u>Yes 9/9/13</u>
172	2014-2016 RSDP	2014-2016 Reliability Standards Development Plan	Reliability Standards Development Plan	Annual Review	8/30/13	9/13/13	<u>Yes 9/13/13</u>
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	<u>Yes 9/16/13</u>
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	<u>Yes 9/16/13</u>

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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	<u>Yes 3/13/14</u>
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	<u>Yes 3/19/14</u>
203	Project 2014-03	Project 2014-03 - Revisions to TOP/IRO Reliability Standards	SAR	Formal	02/21/14	03/24/14	<u>Yes 3/24/14</u>
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	<u>Yes 3/28/14</u>
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	<u>Yes 4/9/14</u>
208	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	MOD-031-1	Formal	02/25/14	04/10/14	<u>Yes 4/10/14</u>
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	<u>Yes 4/14/14</u>
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	<u>Yes 4/16/14</u>
211	Project 2014-04	Project 2014-04 Physical Security - CIP-014-1	CIP-014-1	Formal	04/10/14	04/24/14	<u>Yes 4/24/14</u>
212	Project 2009-03	Project 2009-03 Emergency Operations – EOP-011-1	EOP-011-1	Informal	03/28/14	04/28/14	<u>Yes 4/28/14</u>

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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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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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	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	<u>Yes 9/11/15</u>
284	Project 2007-06	System Protection Coordination	PRC-027-1	Formal	7/29/15	9/11/15	<u>Yes 9/11/15</u>
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	<u>Yes 9/14/15</u>
286	Project 2007-17.4	PRC-005 FERC Order No. 803 Directive	PRC-005-6	Formal	7/30/15	9/16/15	<u>Yes 9/16/15</u>
287	Project 2010-04.1	MOD-031 FERC Order No. 804 Directives	MOD-031-2	Formal	7/31/15	9/18/15	<u>Yes 9/18/15</u>
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	<u>Yes 9/21/15</u>
289	Project 2010-07.1	Vegetation Management	FAC-003-3	Informal	8/24/15	9/28/15	<u>Yes 9/28/15</u>
290	Project 2010-05.3	Phase 3 of Protection Systems: Remedial Action Schemes	PRC-012-2	Formal	8/20/15	10/5/15	<u>Yes 10/5/15</u>
291	Project 2009-02	Real-time Reliability Monitoring and Analysis Capabilities	IRO-018-1 TOP-010-1	Formal	9/24/15	11/9/15	<u>Yes 11/9/15</u>
292	Project 2010-14.2.2	Phase 2 of Balancing Authority Reliability-based Controls	BAL-004-0	Formal	9/24/15	11/12/15	<u>Yes 11/12/15</u>
293	Project 2015-07	Internal Communications Capabilities	COM-001-3	Formal	9/25/15	11/16/15	<u>Yes 11/16/15</u>
294	Project 2007-06.2	Phase 2 of System Protection Coordination	TOP-009-1	Formal	10/6/15	11/19/15	<u>Yes 11/19/15</u>
295	Project 2010-07.1	Vegetation Management	FAC-003-3	Formal	10/30/15	12/16/15	<u>Yes 12/16/15</u>
296	Project 2015-10	Single Points of Failure SAR	TPL-001	Informal	11/12/15	12/17/15	<u>Yes 12/17/15</u>
297	Project 2010-05.3	Phase 3 of Protection Systems RAS	PRC-012-2	Formal	11/25/15	1/8/16	<u>Yes 1/8/16</u>
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	<u>Yes 1/11/16</u>

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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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	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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		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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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
396	Project 2018-04	Modifications to PRC-024-2	PRC-024-2	Formal	4/17/19	5/31/19	Yes 5/31/19
397	Project 2016-02	Modifications to CIP Standards	Virtualization White Paper	Informal	5/30/19	6/28/19	Yes 6/28/19
398	Project 2016-02	Modifications to CIP Standards	CIP-002-6	Formal	6/3/19	7/17/19	Yes 7/17/19
399	Project 2018-04	Modifications to PRC-024-2	PRC-024-2	Informal	6/27/19	7/26/19	Yes 7/26/19
400	Project 2019-03	Cyber Security Supply Chain Risks	CIP-005-6 CIP-010-3 CIP-013-1	Informal	7/2/19	8/1/19	Yes 8/1/19
401	SER	CIP SER	CIP Standards	Formal	7/3/19	8/26/19	Yes 8/26/19
402	Project 2019-04	Modifications to PRC-005-6	PRC-005-6 SAR	Formal	7/30/19	8/28/19	Yes 8/28/19
403	Project 2019-05	Modifications to PER-003-2	PER-003-2	Informal	8/1/19	8/30/19	Yes 8/30/19
404	Project 2016-02	Modifications to CIP Standards	CIP-005	Informal	8/9/19	9/26/19	Yes 9/26/19
405	EMP	Electromagnetic Pulses Task Force Draft Strategic Recommendation	EMP	Informal	8/30/19	9/30/19	Yes 9/30/19
406	Project 2018-04	Modifications to PRC-024-2	PRC-024-2	Formal	9/20/19	11/4/19	Yes 11/4/19
407	Project 2019-06	Cold Weather SAR	SAR	Formal	10/4/19	11/5/19	Yes 11/5/19
408	Project 201707	Standards Alignment with Registration	FAC-002-3 IRO-010-3 MOD-031-3 MOD-033-2 NUC-001-4 PRC-006-4 TOP-003-4	Formal	10/29/19	12/12/19	Yes 12/12/19
409	Project 2016-02	Modifications to CIP Standards	CIP-002-6	Formal	11/1/19	12/16/19	Yes 12/16/19
410	Project	Technical Rationale for Reliability	IRO-001-4 IRO-002-6	Informal	11/4/19	12/18/19	Yes 12/18/19

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		Standards	IRO-006-East-2 IRO-008-2 IRO-009-2 IRO-010-2 IRO-014-3 IRO-017-1 IRO-018-1(i)				
411	Project 2019-02	BES Cyber System Information Access Management	CIP-004-6	Formal	12/20/19	2/3/20	Yes 2/3/20
412	Project 2019-03	Cyber Security Supply Chain Risks	CIP-005-6 CIP-010-3 CIP-013-1	Formal	1/27/20	3/11/20	Yes 3/11/20
413	Project 2019-06	Cold Weather SAR	SAR	Formal	2/19/20	3/19/20	Yes 3/19/20
414	Project	Technical Rationale for Reliability Standards	IRO-001-4 IRO-002-6 IRO-006-East-2 IRO-008-2 IRO-009-2 IRO-010-2 IRO-014-3 IRO-017-1 IRO-018-1(i)	Informal	4/10/20	4/20/20	Yes 4/20/20
415	Project 2020-01	Modifications to MOD-032-1	MOD-032-1	Informal	3/24/20	4/24/20	Yes 4/24/20
416	Project 2020-02	Transmission-connected Resources SAR	MOD-025 MOD-026 MOD-027 PRC-019 PRC-024	Informal	3/30/20	5/13/20	Yes 5/13/20
417	Project 2019-06	Cold Weather SAR	SAR	Informal	4/22/20	5/21/20	Yes 5/21/20
418	SER	Operational Data Exchange Simplification SAR	SAR	Survey	3/12/20	5/27/20	Yes 5/28/20
419	Project 2020-03	Supply Chain Low Impact Revisions	SAR	Informal	4/3/20	6/3/20	Yes 6/3/20
420	Project 2020-04	Modifications to CIP-012	SAR	Informal	4/8/20	6/11/20	Yes 6/11/20
421	Project 2019-03	Cyber Security Supply Chain Risks	CIP-005-6 CIP-010-3 CIP-013-1	Formal	5/7/20	6/22/20	Yes 6/22/20
422	Project 2019-04	Modifications to PRC-005-6	PRC-005-6	Formal	6/2/20	7/8/20	Yes 7/8/20
423	Project 2015-09	Establish and Communicate System Operating Limits	CIP-014-3 FAC-003-5 FAC-011-4 FAC-013-3 FAC-014-3 PRC-002-3 PRC-026-2 TOP-001-6	Formal	6/19/20	8/3/20	Yes 8/3/20

RSC Meeting #22-1, Agenda Item 4.3: Comment History

(As of 2/1/2022)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
			IRO-008-3				
424	2021-2023	Reliability Standards Development Plan	Reliability Standards Development Plan	Informal	8/11/20	9/9/20	Yes 9/9/20
425	Project 2019-03	Cyber Security Supply Chain Risks	CIP-005-7 CIP-010-4 CIP-013-2	Formal	7/28/20	9/10/20	Yes 9/10/20
426	Project 2019-02	BES Cyber System Information Access Management	CIP-004-6	Formal	8/6/20	9/21/20	Yes 9/17/20
427	Project 2015-09	Establish and Communicate System Operating Limits	CIP-014-3 FAC-003-5 FAC-011-4 FAC-013-3 FAC-014-3 PRC-002-3 PRC-026-2 TOP-001-6 IRO-008-3	Formal	10/23/20	12/7/20	Yes 12/7/20
428	Project 2020-05	Modifications to FAC-001-3 and FAC-002-2	SAR	Informal	11/12/20	12/11/20	Yes 12/11/20
429	Project 2018-03	Standard Efficiency Review Retirements	FAC-008-4	Formal	11/30/20	1/13/21	Yes 1/13/21
430	Project 2020-06	Verifications of Models and Data for Generators SAR	MOD-026-1 MOD-027-1	Formal	12/16/20	1/14/21	Yes 1/14/21
431	Project 2019-04	Modifications to PRC-005-6 SAR	PRC-005-6	Formal	1/14/21	2/26/21	Yes 2/26/21
432	Project 2019-06	Cold Weather	EOP-011-2 IRO-010-4 TOP-003-5	Formal	1/27/21	3/12/21	Yes 3/12/21
433	Project 2019-06	Cold Weather	EOP-011-2 IRO-010-4 TOP-003-5	Formal	4/2/21	4/26/21	Yes 4/26/21
434	Project 2017-01	Modifications to BAL-003 White Paper	BAL-003-2	Informal	3/29/21	4/27/21	Yes 4/27/21
435	2020 Periodic Review Standing Review Team	Standards Grading	Standards Grading	Formal	3/22/21	5/5/21	Yes 5/5/21
436	Project 2019-02	BES Cyber System Information Access Management	CIP-004-X CIP-011-X	Formal	3/25/21	5/10/21	Yes 5/10/21
437	Project 2020-04	Modifications to CIP-012	CIP-012	Formal	4/26/21	6/9/21	Yes 6/9/21
438	2021 Standards Grading	2021 Periodic Review Standards Review Team – Standards Grading	21 Eligible Standards	Informal	6/4/21	7/19/21	Yes 7/19/21

RSC Meeting #22-1, Agenda Item 4.3: Comment History

(As of 2/1/2022)

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RSC Meeting #22-1, Agenda Item 4.3: Comment History

(As of 2/1/2022)

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Note: RSC past comment forms are posted on the NPCC Website under “[Standards - Regional Standards Comments](#).”



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