RSC Meeting
December 8, 2022

Report Items:

- NPCC Office Update
- NERC Standards Process Improvement Opportunities

NPCC Office Update

- Office remains in New York
- NPCC's Bylaws require the NPCC office to be in Manhattan County
- Maintain an Office space for 1/3 of Workforce
- 10TH Floor Lease Expires June 2024
- 4th Floor Lease --- 13 years (2036)
- Anticipated Move in 2nd Quarter 2023.

NERC Standards Process Improvements

- Standard Development Process
  - Improve Agility to Address Urgent Reliability Needs
  - Maintain Due Process, Openness and Balance of Interests
- Standards Process Stakeholder Engagement Group (SPSEG)
  - NERC BOT, MRC, NERC Standing Committees, (SC, CCC, RSTC,RISC) and NERC Staff
- SPSEG Recommendations for Incremental Process Improvements
  - NERC Rules of Procedure
  - NERC Standards Processes Manual --- ROP Appendix 3A
- Whitepaper --- Enhancing NERC's Standards Process

NERC Standards Process Improvements

- Streamline the Standard Authorization Process (SAR)
  - Revise SAR Form to Drive Clarity on Reliability Issues
  - Create Single Drafting Team for Standard Development Project
  - Eliminate Prescriptive Language
- Streamline Standard Balloting
  - Tiered Comment Period Structure
  - Eliminate Final Ballot Requirement to Confirm Approval
- Review the Registered Ballot Body Criteria

NPCC REGIONAL STANDARDS COMMITTEE

AGENDA FOR MEETING #22-5

December 8, 2022, 10:00 a.m. – 2:00 p.m. EDT **WebEx Meeting**

Dial-In: 415-655-0003 (USA) / 416-915-6530 (Canada)
Guest Code: 24392561939
Password: RCmBPRJ73*3 (72627757 from phone)
WebEx Link

For Reference:
Glossary of Terms Used in NERC Reliability Standards, dated March 29, 2022
NPCC Glossary of Terms, dated August 10, 2021

Introductions, Safety Message 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/Endorsement

3.1 FERC Activities
3.2 RSC Vice-Chair Nomination and Election
3.3 RSC Scope of Work
3.4 RSC Work Plan
3.5 RSC 2023 Meetings
3.6 Roadmap for Future Revisions to Directory #1 (Endorsement)

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 @ 12:15 PM	10/7/22 (F)	10/7/22 (A)
Project 2017-01 Modifications to BAL-003-1.1 David Lemmons from Greybeard Compliance Services @ 12:30 PM	9/7/22 (I)	9/7/22 (F)
Project 2019-04 Modifications to PRC-005-6 Giuseppe Giannuzzi from HQ @ 1:30 PM	8/25/21 (F)	

Project 2020-04 Modifications to CIP-012 Robert Krackle from Southern Company @ 1:00 PM	11/29/22 (F)	11/29/22 (A)
Project 2020-06 Verifications of Models and Data for Generators Latrice Harkness @ 1:45 PM	1/18/22 (F)	1/18/22 (F)
Project 2021-01 Modifications to MOD-025 and PRC-019	11/14/22 (F)	11/14/22 (I)
Project 2021-02 Modifications to VAR-002	1/13/23 (F)	1/13/23 (I)
Project 2021-03 CIP-002 Transmission Owner Control Centers	12/21/22 (F)	
Project 2021-04 Modifications to PRC-002-2 Ben Wu @ 1:15 PM	11/14/22 (F)	11/14/22 (A)
Project 2021-05 Modifications to PRC-023 Ben Wu @ 1:15 PM	12/5/22 (F)	12/5/22 (I)
Project 2021-06 Modifications to IRO-010 and TOP-003	12/15/22 (F)	12/15/22 (I)
Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination Venona Greaff from Oxy and Alison Oswald @ 12:45 PM	9/1/22 (A)	9/30/22 (F)
Project 2021-08 Modifications to FAC-008	9/21/22 (F)	
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#8 System Restoration --- TFCO Review

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

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 no 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

9.5 FERC and NERC Encourage NAESB to Convene Gas-Electric Forum
FERC, NERC Encourage NAESB to Convene Gas-Electric Forum to Address Reliability Challenges

9.6 2022 State of Reliability Report
Report (nerc.com)

10.0 Future RSC Meetings and Conference Calls

10.1 RSC 2022 Meeting Dates

February 9th, WebEx
May 11th-12th, WebEx
August 10-11th WebEx or Toronto
October 12th-13th WebEx or NYPA
December 8th 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 Assistant Corporate Secretary, Andrew J. Fawbush, Esq. at 904-598-6133.

NPCC REGIONAL STANDARDS COMMITTEE

AGENDA FOR MEETING #22-4

October 12, 2022, 10:00 a.m. – 2:00 p.m. EDT **WebEx Meeting**
DER VER Forum October 13, 2022, 9:00 a.m. – 12:00 p.m. EDT **WebEx Meeting**

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

Day 1 - RSC Business:
Guest Code: 24350475383
Password: Zc7e9pTFE?8 (92739783 from phone)
WebEx Link

Day 2 - DER VER Forum:
Guest Code: 24343720867
Password: Yq2eMFM655* (97236366 from phone)
WebEx Link

For Reference:
Glossary of Terms Used in NERC Reliability Standards, dated March 29, 2022
NPCC Glossary of Terms, dated August 10, 2021

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.	Adrian Pardo	Avangrid	Guest	1
5.	Almir Memic	Eversource	Guest	1
6.	Austin Bond	Eversource	Guest	1
7.	Catherine Ethier	Ontario Energy Board	Guest	1
8.	Chantal Mazza	Hydro Quebec	2	1
9.	Chris Moir	OPG	Guest	1
10.	Constantin Chitescu	OPG	5	1
11.	Damian Interrante	Central Hudson Gas & Electric	1	1
12.	Dan Kopin	VELCO	Guest	1
13.	Dave Kwan	Ontario Power Generation	4	1
14.	Emilia Snyder	Eversource	Guest	1
15.	Erin Wilson	NB Power	1	1
16.	Harish Vijay Kumar	IESO	2	1
17.	Herb Schrayshuen	Power Advisors, LLC	Guest	1
18.	Jason Chandler	Con Edison	Guest	1
19.	Jeff Streifling	NP Power	1	1
20.	Jill Searle	Nova Scotia Power	Guest	1
21.	James Grant	NYISO	2	1

22.	Joel Charlebois	AESI	7	1
23.	John Hastings	National Grid	1	1
24.	John Pearson	ISO-NE	2	1
25.	Joshua London	Eversource	1	1
26.	Julia Ziemelis	Eversource	Guest	1
27.	Junji Yamaguchi	Hydro Quebec	1	1
28.	Kristina Henderson	Avangrid	Guest	1
29.	Lincoln Burton	Con Edison	3	1
30.	Lodie White	FERC	Guest	1
31.	Michele Shafer	The United Illuminating Company	1	1
32.	Michael Foley	Con Edison	4	1
33.	Michael Jones	National Grid	3	1
34.	Nicolas Turcotte	Hydro Quebec	2	1
35.	Quintin Lee	Eversource	1	1
36.	Randy Buswell	VELCO	1	1
37.	Sheraz Majid	Hydro One	1	1
38.	Salvatore Spagnolo	NYPA	4	1
39.	Sean Bodkin	Dominion	4	1
40.	Siobhan Kean-Revie	Orange and Rockland	3	1
41.	Timothy Kucey	PSEG	4	1
42.	Stephanie Ullah-Mazzuca	Orange and Rockland		
43.	Timothy Kucey	PSEG	4	1
44.	Tracy MacNicoll	Utility Service	Guest	1
45.	Vijay Puran	NYDPS	Guest	1
46.	William Temple	Orange and Rockland	Guest	1
47.	Norm Dang	IESO	Guest	1
48.	David Lemmons	Greybeard Compliance Service	Guest	1
49.	Giuseppe Giannuzzi	Hydro Quebec	Guest	1
50.	Tony Hall	LGE	Guest	1
51.	Robert Krackle	Southern Company	Guest	1
52.	Alison Oswald	NERC	Guest	1
53.	Matthew Harvard	SPP	Guest	1

Introductions, Safety Message and Chair's Remarks
Gerry Dunbar provided remarks on the latest industry activities.

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

Agenda Items:

1.0 Review of Agenda
Gerry Dunbar reviewed the meeting agenda with the group.

2.0 RSC Meeting Minutes (Approval Item)
Approval of the October 12, 2022, RSC meeting minutes – No revision is necessary to the draft RSC meeting minutes that were provided in the agenda package
Quintin Lee made the motion for approval.
Sean Bodkin seconded the motion.
The October 12, 2022, RSC meeting minutes were approved

3.0 Items Requiring RSC Discussion

3.1 FERC Activities

Kal Ayoub updated the group on the FERC and DOE joint technical conference on Supply Chain Risk Management, incentives for Advanced Cybersecurity investment, and demonstration of potential data/calculation workflows under FERC Order No. 881's Ambient-Adjusted Rating (AAR) requirements.
Federal Register :: Incentives for Advanced Cybersecurity Investment; Cybersecurity Incentives
Demonstration of Potential Data/Calculation Workflows Under FERC Order No. 881's Ambient-Adjusted Rating (AAR) Requirements | Federal Energy Regulatory Commission

3.2 DER/VER Guidance Document Version #3 Appendix J Open Process

DER/VER Guidance Document Appendix J is currently open for industry comment process until November 7, 2022. At the conclusion of the open process, NPCC Standards Staff will review and respond to all industry comments. Ruida Shu will send out an email endorsement to the RSC members to seek endorsements so the document can be sent to RCC for final endorsement at the December 6, 2022, meeting.

3.3 Roadmap for Future Revisions to Directory #1

A 'Roadmap' providing guidance for future revisions of Directory #1 has been drafted and reviewed by the TFCO and TFCP. The Roadmap highlights current industry issues and suggests enhancements to the criteria that address resource adequacy metrics, energy sufficiency in all hours, gas/electric interdependency and extreme weather. The Roadmap has been provided to the RSC and RCC for comment and will be presented to each committee for endorsement in December.

3.4 PRC-006-NPCC-2 UFLS Discussion
Gerry Dunbar reviewed issues surrounding PRC-006-NPCC-2 UFLS with the RSC group.

3.5 RSC 2023 Meetings
We will have some proposed dates for next year for RSC members to review during the December 2022 RSC meeting.

3.6 RSC Scope of Work and Work Plan
Sheraz Majid and Mike Jones volunteered to help update and revise the RSC Scope of Work and Work Plan.

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 @ 12:15 PM NC	10/7/22 (F)	10/7/22 (A)
Project 2017-01 Modifications to BAL-003-1.1 David Lemmons from Greybeard Compliance Services @ 12:30 PM	9/7/22 (I)	9/7/22 (F)
Project 2019-04 Modifications to PRC-005-6 Giuseppe Giannuzzi from HQ @ 12:45 PM	8/25/21 (F)	
Project 2020-03 Supply Chain Low Impact Revisions Tony Hall @ 1:00 PM	8/19/22 (F)	8/19/22 (I)
Project 2020-04 Modifications to CIP-012 Robert Krackle from Southern Company @ 1:15 PM	11/16/22 (F)	11/16/22 (A)
Project 2020-06 Verifications of Models and Data for Generators Alison Oswald @ 1:45 PM	7/6/22 (F)	7/6/22 (F)
Project 2021-01 Modifications to MOD-025 and PRC-019	11/14/22 (F)	11/14/22 (I)
Project 2021-02 Modifications to VAR-002	4/6/22 (I)	
Project 2021-03 CIP-002 Transmission Owner Control Centers		
Project 2021-04 Modifications to PRC-002-2 Ben Wu/Ruida Shu	11/9/22 (F)	11/9/22 (A)
Project 2021-05 Modifications to PRC-023 Ben Wu/Ruida Shu	9/15/22 (F)	9/15/22 (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 Matthew Harward from SPP @ 1:30 PM	9/1/22 (A)	9/30/22 (F)
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		

Project 2016-02:
CIP-007 barely passed.
CIP-005 and CIP-010 are not passed.
Concerns regarding IRA and ERC.
The drafting team will meet tomorrow afternoon October 13, 2022.

Project 2017-01:
BAL-003 was posted for ballot and comments.
The ballot is about 40 percent approval.
The requirements can be addressed through other standards but it is not currently.

Project 2019-04:
The next SDT meeting is tomorrow October 13, 2022.
The SDT is in the process of reviewing the technical rationale document.
The goal is to post the project (initial posting for phase II) for comment and ballot by the end of the year.
The posting will include the protection system definition.

Project 2020-03:
Project is passed with 66.8% approval.
Allow vendor electric remote access in section 6
The standard drafting team added vendor electric remote access in section 6.3.
The final ballot will start on October 26, 2022.

Project 2021-07:
Phase I of the project passed the final ballot.
There are four recommendations from the NERC FERC Cold Weather Report are addressed by Phase I.
Phase II project started, the SDT meeting started October 11, 2022, and the team started addressing the remaining 6 recommendations from NERC FERC Cold Weather Report.
Phase II deadline is September 2023.
The next drafting team meeting is on Thursday October 13, 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 <u>NPCC Non-Standards</u>

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

A Joint Planning and Operations Working Group is currently reviewing Directory #1. The Working Group anticipates posting Directory#1 in January.

5.1.2 Directory#8 System Restoration --- TFCO Review

The TFCO is reviewing comments received on a revised draft of Directory #8.

5.1.3 Directory #5 Reserve --- Clarification ---- Approved.

The RCC approved a TFCO Criteria Clarification for Directory #5 Requirement R6. The Clarification addressed sustainability of reserve and has been archived on the NPCC website.

6.0 <u>RSC Member Items of Interest</u>

6.1 RSC Roster

7.0 <u>Standards Activity Post NERC BOT Approval</u>

(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 <u>NERC Meetings</u>

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

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

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 <u>NERC Items of Interest</u> (Since last RSC Meeting)

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

9.1.1 There have been two 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

9.5 FERC and NERC Encourage NAESB to Convene Gas-Electric Forum
FERC, NERC Encourage NAESB to Convene Gas-Electric Forum to Address Reliability Challenges

9.6 2022 State of Reliability Report
Report (nerc.com)

10.0 Future RSC Meetings and Conference Calls

10.1 RSC 2022 Meeting Dates

February 9th, WebEx
May 11th-12th, WebEx
August 10-11th WebEx or Toronto
October 12th-13th WebEx or NYPA
December 8th General Meeting or WebEx

The meeting is adjourned at 2:20 PM.

NPCC Distributed Energy Resources/Variable Energy Resources Forum

October 13, 2022, 9:00 a.m. – 12:00 p.m. EDT WebEx Meeting

Dial-In: 415-655-0003 (USA) / 416-915-6530 (Canada)
Guest Code: 24343720867
Password: Yq2eMFM655* (97236366 from phone)
WebEx Link

Attendance:

	Name	Organization	Comments
1	Gerry Dunbar	NPCC	
2	Ruida Shu	NPCC	
3	Aaron Hornick	NPCC	
4	Abdualah Aljankawey	NB Power	
5	Aditya Menon	Hydro One	
6	ahmed mousa	PSEG	
7	Al McMeekin	NERC	
8	Andrey Oks	NPCC	
9	Anil Rauniyar	NPCC	
10	Austin Bond	Eversource	
11	Ben Eng	NPCC	
12	Benjamin Loebick	UI	
13	Brad Woods	Texas RE	
14	Brett Feldman	RI Energy	
15	Carleton Simpson	PUC NH	
16	Casey Darling	Central Hudson	
17	Catherine Ethier - OEB	OEB	
18	Chantal Mazza	Hydro Quebec	
19	Charles Dickerson	NPCC	
20	Charlie Smith	ESIG	
21	Chris Moir	OPG	
22	Christian Garneau	Regie	
23	Constantin Chitescu	OPG	
24	Damian Interrante	Centra Hudson	
25	Dan Kopin	VELCO	
26	Daniel Schwarting	ISO-NE	
27	David Conroy	RLC-Eng	
28	Dean Sorensen	National Grid	
29	Deketa Wall	NPCC	
30	Dick Brooks (REA)	Reliable Energy Analytics	
31	Douglas Vitale	NPCC	
32	Eddy Lim (FERC)	FERC	

33	EDWARD ROEDEL	UI	
34	Emilia Snyder Eversource	Eversource	
35	Erin Wilson	NB Power	
36	F.Wong	Regie	
37	Feras Shehadeh	WSP	
38	Gabriel Dion (HQ)	Hydro Quebec	
39	Gene Ng	Hydro One	
40	Geneva McSheffery	NB Power	
41	Hantz Presume	VELCO	
42	Harish Vijay Kumar	IESO	
43	Harman Paink	AESI	
44	Hongling Sun	Hydro One	
45	Irene Lu	National Grid	
46	James Oddy	FERC	
47	Jason Chandler	Con Edison	
48	Jason Pause	DPS.NY	
49	Jeffrey Streifling	NB Power	
50	Jim Grant	NYISO	
51	Jean Morneau	Hydro One	
52	Joel Charlebois	AESI	
53	John Baudanza	National Grid	
54	John Hastings	National Grid	
55	John Idzior	Reliability First	
56	John Pearson	ISO-NE	
57	John Penaranda	Hydro One	
58	Jones, Michael W.	National Grid	
59	Joshua London - Eversource	Eversource	
60	Kim McKinley	NB Power	
61	Kurtis Chong	IESO	
62	Lincoln Burton	Con Edison	
63	Ling Zheng	Con Edison	
64	Louis Legault	Regie	
65	Maria G.	Regie	
66	Mark Henry	Texas RE	
67	Megan Lund	IESO	
68	Michael Lombardi	NPCC	
69	Michael Ridolfino (CHG&E)	Central Hudson	
70	Michele Shafer	NYSEG	
71	Mike Foley	Con Edison	
72	Mike Sylvester	National Grid	
73	Mujahid Mian	NPCC	
74	Neeraj Lal	NPCC	
75	Nicola Parrotta	TMLP	
76	Nima Kalathil	National Grid	
77	Patrick Scully	Maine,gov	

78	Per-Anders Lof	National Grid	
79	Peter Van Huynh	NS Power	
80	Phil Jonat, WSP	WSP	
81	Pramila	NYISO	
82	Quintin Lee	Eversource	
83	Rafael Sahiholamal	NPCC	
84	Randy Buswell	VELCO	
85	Randy Crissman	NYPA	
86	Randy Davis	Maine.gov	
87	Riley Allen	Vermont.gov	
88	Rizki Del Olmo	PSEG	
89	Robert Eisenhuth	PSEG	
90	Scott Nied	NPCC	
91	Sean Sampson	WSP	
92	shayan rizvi	NPCC	
93	Sheila Keane	NESCOE	
94	Shengen Chen	RLC-Eng	
95	SHERAZ MAJID	Hydro One	
96	Siobhan Keane-Revie	ORU	
97	Tasha Hescock	Utility Services	
98	Ted Zhou	Hydro One	
99	Thomas Teafatiller	Reliability First	
100	Thomas zhao	Hydro One	
101	Tom Burns	Central Hudson	
102	Tony Napikoski UI	UI	
103	Tony Purgar	Reliability First	
104	Tracy MacNicoll	Utility Services	
105	Vijay Puran	DPS.NY	
106	Walid Ommary	Hydro One	
107	WARREN KING	Hydro One	
108	Werner Pieterse	IESO	
109	William Vesely	Con Edison	
110	Wai Wong	National Grid	
111	Yves Albert	NB Power	
112	Zhu, Chuanjiang (Chelsea)	National Grid	

Day Two NPCC Regional Standards Committee Meeting – DER VER Forum:

October 13, 2022, 9:00 a.m. – 12:00 p.m. (all times EDT)

11.0 Distributed Energy Resources (DER) Variable Energy Resources (VER) Forum Topics

11.1 Welcome and Safety Message: Gerry Dunbar, NPCC Director Reliability Standards and Criteria (9:00 am - 9:05 am)

11.2 Antitrust Compliance Guidelines, Public Notice, and Meeting Protocols: Ruida Shu, NPCC Manager of Reliability Standards (9:05 am – 9:10 am)

11.3 NPCC VER/DER Outreach Efforts: Gerry Dunbar, NPCC Director Reliability Standards and Criteria (9:10 am – 9:15 am)

11.4 Operational Challenges of DER Integration at the Transmission-Distribution Interface – John Penaranda, Grid Operations Manager, Hydro One Networks (9:15 am – 9:55 am)

11.5 Planning New England's Transmission Grid for 2040 and 2050 – Daniel Schwarting, Manager, Transmission Planning, ISO-New England (9:55 am – 10:35 am)

Break (10:35 am – 10:40 am)

11.6 Leveraging Existing Planning Process to Prepare for the Energy Transition – Megan Lund, Manager – Transmission Planning Southwest & East, Independent Electricity System Operator (10:40 am – 11:20 am)

11.7 Transmission, a Key Enabler of the Energy Transition – Charlie Smith, Executive Director, Energy Systems Integration Group (11:20 am – 12:00 pm)

11.8 Closing – Gerry Dunbar

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 Assistant Corporate Secretary, Andrew J. Fawbush, Esq. at 904-598-6133.

Distributed Energy Resources and Variable Energy Resources Forum Disclaimer Statement

1. General

Any information presented [at NPCC forums] is for informational purposes only. NPCC accepts no responsibility for the accuracy of such presentations, or for your reliance on any information contained within the content available through such forums. Discussions represent a wide range of views and interests of the participating individuals and organizations. Statements made during discussions do not necessarily reflect those of NPCC.

2. Vendors

Information presented is for stakeholder informational purposes only and does not imply NPCC's endorsement or approval. NPCC does not promote technology, tools, products, services, or vendors that may be used by entities within the electric industry. Questions or concerns about vendors or the services or products they offer must be directed to the vendor. It is the responsibility of the owner, operator, or the user of the bulk power system to research the services the vendors offer. Those that utilize the services of vendors assume full responsibility for claims directly or indirectly arising thereunder and NPCC is not responsible or liable for any claim or harm, directly or indirectly, that transpires from the use of any information.

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.

Meeting Logistics

Participants will be muted upon entry, and you are encouraged to use the "Chat" feature of the WebEx if you wish to ask a question. The questions will be answered by the presenter at the end of each presentation. NPCC DER/VER Forum will be recorded, the recording and meeting material will be posted on the DER Forum section of the NPCC website.

Thank you for your cooperation.

Update on FERC Activities

Kal Ayoub, Deputy Director, Division of Cyber Security

December 8, 2022

The views expressed in this presentation are my own and do not represent those of the Commission or any individual Commissioner.

FERC Reliability-Related Activity

- Implementing Recommendations of FERC-NERC Inquiry on 2021 Cold Weather Event
- Security and Reliability-Related Issuances
- 2022 Report on Lessons Learned from the FERC-led Cybersecurity Audits
- FERC Technical Conferences
- Joint Federal–State Task Force on Electric Transmission

FERC-NERC Cold Weather Inquiry: NAESB Gas-Electric Forum

- ***July 29, 2022,*** Chairman Glick and Mr. Robb recommended that NAESB convene a forum to address Recommendation 7.
- ***Recommendation 7:*** FERC should consider establishing a forum. . . .to identify concrete actions (consistent with the forum participants' jurisdiction) to improve the reliability of the natural gas infrastructure system necessary to support bulk-power system reliability.
- ***Goals***:
  - ✓ Concrete actions to increase reliability of the natural gas infrastructure system necessary to support [the] Bulk Electric System;
  - ✓ Plans for implementing actions;
  - ✓ Deadlines for implementing actions; and
  - ✓ Identifying entities responsible for implementing actions.
- ***NAESB Gas-Electric Forum meetings***: September 23, 2022; October 21, 2022; November 8, 2022; and December 1, 2022. Meetings are open to the public.

2021 FERC-NERC Cold Weather Inquiry: Cold Weather Reliability Standards

- October 28, 2022 – NERC filed Extreme Cold Weather Grid Operations, Preparedness, and Coordination Reliability Standards for approval in Docket No. RD23-1. Comments are due December 1.
- Revisions address the reliability-related findings of the Joint Inquiry into the February 2021 Cold Weather Outages in Texas and South-Central United States and five of the recommendations for new or enhanced Reliability Standards proposed in the Joint Report.
- Represents the first phase of a two-phase effort to implement Recommendation 1 of the 2021 inquiry.
- The proposal:
  - Revised Reliability Standards EOP-011-3 Emergency Operations and adds a new EOP-012-1
    Extreme Cold Weather Preparedness and Operations;
  - Adds three definitions; and
  - Retires EOP-011-2 Emergency Preparedness and Operations.

Security and Reliability-Related Issuances

- **Order accepting FY2023 Business Plans and Budgets and directing a Compliance filing**, issued November 2, 2022 (Docket No. RR22-4-000).

- **Orders focused on inverter-based resources (IBRs),** issued November 17, 2022**:**
  - An order directing NERC to develop a plan to register the entities that own and operate IBRs (RD22-4);
  - A Notice of Proposed Rulemaking (NOPR) to direct NERC to develop reliability standards for IBRs that cover data sharing, model validation, planning and operational studies, and performance requirements (RM22-12);
    - **Comments on the NOPR are due on February 6, 2023; Reply Comments are due on March 6, 2023**
  - An order approving reliability standards that are related to IBRs, which NERC proposed earlier this year (RD22-5).

Lessons Learned from CIP Reliability Audits

- FERC staff issued its annual report on lessons learned from the non-public CIP audits of registered entities. It found that most cybersecurity protection measures adopted by entities met the mandatory requirements of the CIP reliability standards.
- The report recommends cybersecurity practices that include processes, procedures and technical controls to mitigate risks.
  - Re-evaluate policies, procedures, and controls for low-impact cyber systems and associated cyber assets (CIP-003);
  - Address risks posed by bulk electric system cyber assets that have reached the manufacturer-determined end of life or service and no longer are supported by vendors (CIP-007);
  - Deploy a comprehensive malicious code prevention program for all cyber assets within a bulk electric system cyber system (CIP-007);
  - Implement comprehensive vulnerability assessment processes for applicable cyber assets (CIP-010); and
  - Review and validate controls used to mitigate software vulnerabilities and malicious code on transient cyber assets managed by a third party (CIP-010).

Technical Conferences

- ***New England Winter Gas-Electric Forum*** was held on September 8, 2022. AD22-9-000. The Commissioner-led forum discussed the electricity and natural gas challenges facing the New England Region.

- ***Annual Commissioner-led Reliability Technical Conference*** will be held on November 10, 2022. AD22-10-000. The conference will discuss policy issues related to the reliability and security of the Bulk-Power System. Panel I will explore Managing the Electric Grid to Advance Reliability; and Panel II will explore Managing Cyber Security Threats, CIP Reliability Standards and best practices for the Bulk-Power System.

Technical Conferences

- **Establishing Interregional Transfer Capability Transmission Planning and Cost Allocation Requirements Workshop** will be held on December 5-6, 2022. AD23-3-000. The workshop will discuss whether and how the Commission could establish a minimum requirement for interregional transfer capability for public utility transmission providers in transmission planning and cost allocation processes.

- ***Supply Chain Risk Management Technical Conference*** will be held on December 7, 2022. AD22-12-000. DOE's Office of Cyber Security, Energy Security, and Emergency Response (CESER) and FERC's Office of Electric Reliability will hold a technical conference to discuss supply chain security challenges related to the Bulk-Power System, ongoing supply chain-related activities, and potential measures to secure the supply chain for the grid's hardware, software, computer, and networking equipment.

Joint Federal-State Task Force on Electric Transmission

- ***Announced*** (June 17, 2021, in Docket No. AD21-15). The purpose is to encourage cooperation and communication between federal and state regulators on electric transmission related issues.
- ***The First meeting*** (November 10, 2021) focused on incorporating state perspectives into regional transmission planning.
- ***The Second meeting*** (February 16, 2022) focused on categories and types of transmission benefits that should be considered in transmission planning and cost allocation and its principles.
- ***The Third meeting*** (May 6, 2022) focused on examining barriers to the efficient, expeditious, and reliable interconnection of new resources through the FERC-jurisdictional interconnection processes.
- ***The Fourth meeting*** (July 20, 2022) focused on Interregional Transmission Planning and Project Development
- ***The Fifth meeting*** (November 15, 2022) focused on addressing regulatory gaps and challenges in oversight of transmission development.

Recordings of these meetings are available at Joint Federal-State Task Force on Electric Transmission.

Questions?

2023 Scope of Work for the Regional Standards Committee

The NPCC Regional Standards Committee ("RSC") aligns its activities with the NPCC and NERC Strategic Plans and is charged with:

(a) Managing and maintaining the NPCC Regional Standards Development Process.
(b) Managing and maintaining the process for NPCC Criteria and Directory Development.
(c) Providing consolidated NPCC Regional review and comments to existing and proposed NERC Standards in accordance with the NERC Reliability Standards Development Processes.
(d) Reviewing FERC Orders and Notice of Proposed Rulemakings ("NOPRs") related to Reliability Standards.
(e) Reviewing any new and revised NERC Reliability Standard Audit Worksheet ("RSAW"), as may be requested by the NPCC Compliance Committee ("CC") and submit comments to NERC as appropriate.
(f) Providing consolidated NPCC Regional review and comments to the existing and proposed NERC Standards Development Processes Manual and to the NERC Rules of Procedure as they relate to Standards Development.
(g) Determining the need for, and development of, NERC and Regional Standards, Variances to NERC Standards, modifications to NPCC Criteria and Directories, and/or interpretations and clarifications thereof.
(h) In coordination with the NPCC CC, address issues identified through the NPCC Regional Feedback Mechanism to continually improve standards and NERC documents which includes Guidelines and other technical material.
(i) In coordination with the Reliability Coordinating Committee ("RCC"), address issues identified through the "Distributed Energy Resource ("DER") BES Impact Reporting Form", conduct, maintain, and further develop the process as necessary.
(j) Providing a forum for information with the goal of sharing best practices on reliability issues associated with industry standards, guidance and/or regulations. In addition, forum topics may include emerging issues such as building electrification, electric vehicle charging, and transmission integration.
(k) After receiving comments from NPCC stakeholders, the RSC will be responsible for coordinating consensus and the NPCC Standards Program Area Staff will submit Regional comments to NERC.

The RSC is an open and balanced committee inclusive of all stakeholders that provide for, or are materially impacted by, the reliability of the NERC Bulk Electric System and the NPCC Bulk Power System as defined by Criteria A-10. The RSC meetings are open to all stakeholders who want to participate, and meeting materials will be publicly posted on the NPCC Website.

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

The RSC will coordinate its work through the NPCC Standards Program Area Staff which will submit standards related comments pursuant to the NERC Standards Development Processes Manual and the NERC Rules of Procedure.

The RSC will be chaired and assisted by NPCC Standards Program Area Staff along with Co-Vice chairs elected by the RSC from among the members of the RSC at the time the vote is taken. Chair and Co-Vice Chair appointments will be submitted to the NPCC Board of Directors for final approval. The Co-Vice chairs will serve a term of two years. The Vice-Chair term may be extended through a motion and subsequent vote by the committee.

Members of the RSC will be nominated by their respective companies. NPCC RSC leadership (RSC Chairperson and Co-Vice Chairpersons) will review and consider the approval of all nominations to the RSC. The nominations will include contact information and qualifications to serve on the committee highlighting the ability of the nominee to work with their subject matter experts and sufficiently represent their organization's viewpoint on the Committee. Each of the NPCC Sectors as defined in the NPCC Amended and Restated Bylaws will be open to representation on the RSC in accordance with the NPCC Amended and Restated Bylaws.

Subcommittees and ad hoc Working Groups will be formed upon request of the RSC by NPCC Standards Program Area Staff. All associated scopes or charters developed, will be approved by the RSC.

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

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

RSC Members should consider not only what is best for their company but also what is in the best interest of the broader industry and NERC Bulk Electric System and NPCC Bulk Power System reliability.

RSC Members should make every effort to attend scheduled meetings and when not available are required to identify and provide a qualified proxy participant. RSC business cannot be conducted in the absence of a quorum, and it is essential that each RSC Member make a commitment to be present. A determination to recommend removal of an RSC member shall be considered by the NPCC RSC leadership if that member is excessively absent and provides no proxy for regularly scheduled meetings. In this case the NPCC Member Representative will be notified of the intent to remove the member from the Roster prior to the formal removal of that member.

A. NPCC Regional Standards Process Responsibilities

The RSC is responsible for managing the Regional standards process for the development of

ERO Regional Standards, Violation Risk Factors (“VRFs”), Violation Severity Levels (“VSLs”), definitions, Regional Interconnection-wide variances (e.g., Quebec’s UFLS), interpretations and clarifications in accordance with the NPCC Regional Standard Processes Manual and the NPCC Amended and Restated Bylaws pertaining to quorum and voting rules. The RSC is responsible for promoting and pursuing the quality of all standards-related materials.

The RSC will be available to advise the NPCC BOD on NERC standards related matters.

B. NPCC Criteria and Directory Process Responsibilities

The RSC provides oversight for the development of NPCC Criteria and Directories within each document. The RSC will provide guidance to all NPCC Committees, Task Forces and Working Groups regarding NPCC documents including Criteria, Directories, Procedures, Guidelines, and the Cost Effectiveness Procedure. The RSC will also maintain and oversee the Directory Development and Revision Manual and related processes. Distributed Energy Resource (“DER”) BES Impact reporting activities will be coordinated with the Reliability Coordinating Committee (“RCC”).

The RSC will be available to advise the NPCC BOD on NPCC Criteria and Directory related matters.

C. NERC Reliability Standards Responsibilities

The RSC will:

- Provide a forum for NPCC review, coordination, and submission of regional comments to existing or proposed NERC Reliability Standards when posted for NERC “Open Process Review.”
- Provide a forum for NPCC to participate, solicit and provide Regional comments on Standard Authorization Requests (“SARs”) and their respective Reliability Standards in accordance with the NERC Standard Development Processes Manual.
- Provide a forum for NPCC to participate in and be kept aware of emerging risks from the NERC Reliability Issues Steering Committee (“RISC”) and Reliability and Security Technical Committee (“RSTC”).
- Provide a forum for NPCC to participate, solicit and provide Regional comments to the Periodic Review Process for standards.
- Identify prospective reliability issues associated with new or revised NERC Reliability Standards and their potential impact on the NPCC Region, (e.g., Regional differences).
- Propose solutions to standards development issues, emerging reliability risks and guide the development of the NERC Reliability Standards through comments and coordination of NPCC participation on the SAR, Periodic Review and Reliability Standard Drafting Teams.
- Engage participants across the NPCC membership during the standard commenting process to achieve broad Regional consensus.
- Followup on proposed and adopted changes to the NERC Standard Development Processes Manual and Rules of Procedure as they apply to Reliability Standards and provide NPCC members with information to achieve a common understanding of the

processes.

- Coordinate the activities of NPCC members on Standard Drafting Teams and encourage NPCC representation on all Standard Drafting Teams.
- Coordinate with the NPCC CC on input to CMEP Implementation Guidance documents in accordance with the CC process for submitting implementation guidance to NERC.
- Participate in the NERC Standards Efficiency Review and coordinate Regional participation in related efforts.
- Conduct DER and VER forums to promote best practices and information sharing as NPCC experiences increased penetration of DER and VER.
- Conduct outreach with State and Provincial Governmental authorities to provide an industry point of contact for regulatory mandates.
- Promote the targeted reliability activities in the NPCC Strategic Plan and the ERO Long term strategy focus areas.

D. FERC Activities Affecting Standards

The RSC will review and discuss FERC Orders and Notice of Proposed Rulemakings ("NOPRs") relating to ERO and Regional Reliability Standards.

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

E. Non-Jurisdictional

The RSC will conduct activities as necessary to promote reliable integration of new resources including but not limited to DER and VER. The focus of the RSC activities is to inform stakeholders of new technologies, planning techniques, operational impact and opportunities to leverage the characteristics of new technologies to provide and enhance essential reliability services. Provide support for Regional de-carbonization goals by monitoring NPCC Criteria and Directory development and revision for reliability, security, and resilience issues as well as impediments to meeting decarbonization goals. Additionally, the RSC will develop, and revise guidance documents and procedures related to these new technologies.

NPCC Board of Directors Meeting
XX_XX, 2023
Draft for Approval, Agenda Item XX

Northeast Power Coordinating Council, Inc.
Regional Standards Committee
Work Plan for Calendar Years 2023-2024

The following Regional Standards Committee ("RSC") Work Plan activities for the calendar years of 2023-2024 will be consistent with the NPCC 2023 and 2024 Business Plans and Budgets, 2023-2026 Working Draft Strategic Plan, and continues to support the Distributed and Variable Energy Resource Forums along with other reliability activities related to de-carbonization goals in the Region. The Work Plan supports the 2023 ERO Enterprise Work Plan Priorities and the ERO Reliability Standards Development activities including ongoing standards periodic reviews, standards development, standards efficiency reviews, and standards grading.

NPCC Reliability Standards Committee Program Responsibilities (related to Standards)

The RSC's work will be informed by the Strategic Reliability Focus Areas defined in the 2023-2026 Working Draft NPCC Strategic Plan. Those focus areas are: 1) Enhancing System Resilience and Assuring Energy Sufficiency 2) Reliably Integrating the Resources brought forward by Societal Decarbonization 3) Addressing Cyber and Physical Threats.

1. Monitor NERC's Reliability Issues Steering Committee ("RISC") risk profiles and other reliability related issues and priorities. Review the 2023 ERO Reliability Risk Priorities Report for NERC and NPCC Standards and Criteria development, or for the development of guidelines or other reliability solutions. Coordinate NPCC's input into those decisions.
2. Coordinate and provide input to the development and prioritization of ERO reliability standards within the NERC Reliability Standards Development Plan through active Regional participation with the Periodic Review Standing Review Team or successor group or related activity.
3. Provide ongoing input to the NERC Standards Periodic Review Template used to determine the effectiveness of standards.
4. Continue to coordinate Regional input for cost effectiveness activities conducted during NERC's Standards Development program.
5. Oversee, and participate in the Regional Standards Development Process and base any development, revision, or retirement of NPCC Regional Reliability Standards on the continued reliability related needs of the Region or continent-wide ERO standards and initiate any future revision(s) which may be necessary.
6. Coordinate any NPCC Regional Standards development activity with NERC Standards development activity to avoid duplication and ensure resources are available for efficient and effective standards development and implementation.
7. Engage in the NERC Compliance Guidance Policy process. Support the inputs through the NPCC Compliance Committee ("CC") by providing technical and policy related opinions as necessary.
8. Coordinate NPCC participation in reviews and revisions of NERC Standards when addressing reliability directives from FERC and any Provincial Governmental Authority directives.
9. Participate in any NERC Task Forces, Working Groups, and Subcommittees which may drive NERC and NPCC standards development activities.
10. Conduct thorough reviews of all NERC Standards being developed or revised and coordinate timely consensus-based comments within the NPCC Region based on reliability needs, results-based requirements, and Periodic Reviews activities by leveraging the expertise of the NPCC RSC and Task Forces.
11. Develop and submit Standard Authorization Requests ("SARs") for revisions when necessary to improve Standards and address reliability related issues for approved or draft Standards.
12. Develop, as needed, any Interconnection Wide Regional variances for NERC Reliability Standards and NPCC Regional Standards in accordance with the NPCC Regional Standard Process Manual.

13. Develop ballot recommendations or provide a list of reliability or compliance issues to RSC members and NERC Registered Ballot Pool entities within NPCC for all NERC Standards under development.
14. Review and develop ballot recommendations for any future NERC formal interpretations to Standards.
15. Provide guidance to NPCC Regional Standard Drafting Teams in critical areas of results-based Standards, Violation Severity Levels, and Violation Risk Factor development as well as ensuring quality.
16. Respond to FERC and Provincial filings and interrogatories on issues related to Regional and NERC Standards as requested. Coordinate formal NPCC input to NERC filings and petitions.
17. Serve as a liaison for the Northeast Region to the NERC RISC for all new and emerging reliability risks related to the development or revision of standards.
18. Coordinate input for the Northeast Region to the NERC Reliability and Security Technical Committee (“RSTC”) as necessary.
19. Participate in or observe the proceedings of various NERC groups to contribute to the continued improvement of NERC Standards and processes. These groups include but are not limited to:
    a. NERC Standards Committee (“SC”)
    b. NERC Standards Committee Process Subcommittee (“SCPS”)
    c. NERC Project Management Oversight Subcommittee (“PMOS”)
    d. NERC SAR and Standards Drafting Teams (“SDTs”)
    e. NERC RISC
    f. NERC RSTC
20. Develop proposals for standards, variances, and standard clarifications utilizing Regional technical resources as assigned by the NPCC Reliability Coordinating Committee, or RSC.
21. Work with the NPCC Compliance Committee and Staff to develop the necessary compliance elements of the Regional Standards, for example, Violation Severity Levels (“VSLs”).
22. Revise, as necessary, and implement the NPCC Cost Effective Analysis Procedure and apply it to Directories being revised or developed, as needed. Promote and participate in any NERC cost effectiveness analysis activities conducted during formal industry comment periods of the ERO draft continent-wide Standards.
23. Ensure that the appropriate NPCC Task Forces review NERC Standards-related issuances and provide input to support development of a NPCC consensus opinion based on cost effectiveness.
24. Solicit technically qualified candidates from NPCC stakeholder companies to participate on each of the NERC Standard Drafting Teams. Ensure sufficient regional representation exists on the drafting teams.
25. Promote among NPCC stakeholders, and State and Provincial regulators issues related to BES reliability and Standards development.
26. Participate in NPCC Compliance and Reliability Conferences.
27. Participate in the revision and redrafting of the NERC Rules of Procedure and other documents related to standard development as the NERC documents come up for review and /or modification.
28. Coordinate implementation of the NERC Standards development processes and NPCC Regional Standard processes and recommend revisions as necessary.
29. Coordinate with the RCC, all activities related to input received from the “Distributed Energy Resources BES Impact Reporting Form.”
30. Provide oversight, and further develop as may be necessary, the process, information, and promotion of the “Distributed Energy Resources BES Impact Reporting Form.”
31. Conduct DER/VER Forum Meetings as required.
32. Develop revisions to and maintain NPCC DER/VER Guidance document(s) and processes.
33. Coordinate and work with State and Provincial Governmental Authorities to address reliability and resilience related issues associated with DER/VER, and energy storage as decarbonization goals are pursued.

NPCC Regional Standards Committee Program Responsibilities (related to Criteria and Directories)

1. Coordinate NPCC Directory Development activities with the regulatory authorities in the U.S. and applicable Provincial Governmental Authorities.
2. Identify the need for new or modified NPCC Criteria and Directories, Guidelines and Procedures pursuant to Section 313 of the NERC ROP responsibilities.
3. Revise and maintain the NPCC Directory Development and Revision Manual & Process for the Review

and Approval of Criteria, Guidelines, and Procedures as needed to identify incremental reliability benefit and cost effectiveness as directed by the NPCC Board of Directors and Full Members.

4. Coordinate Criteria and Directories requirements with Regional and NERC Standards requirements to ensure no inconsistencies or duplication exists and identify potential areas for improvements.
5. Develop filings for the Directories for the New York State Public Service Commission to fulfill obligations for the "Carve-out" outlined in Order 672 for mandatory adherence to more stringent Regional criteria for New York State.
6. Develop filings of Directories as required with the Provincial Governmental Authorities as per the various Memorandums of Understanding.
7. Announce development activities pertaining to the NPCC Reliability Directories and NPCC guidance documents which will enable users, owners, and operators of the Bulk Power System in the Region to be aware of and apply the NPCC Regionally specific criteria.

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

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

45-day formal comment period with ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting (SAR submitted by NERC RS)	June 14, 2017
Standards Committee approved Standard Authorization Request (SAR) for posting (SAR submitted by NWPP FRSG)	October 18, 2017
SAR posted for comment (SAR submitted by NERC RS)	June 16, 2017 – July 18, 2017
SAR posted for comment (SAR submitted by NWPP FRSG)	November 2, 2017 – December 1, 2017
Reliability Standard BAL-003-2	November 5, 2019

Anticipated Actions	Date
45-day formal comment period with ballot	July 25, 2022
45-day formal comment period with additional ballot	TBD
10-day final ballot	TBD
Board adoption	TBD

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

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

Term(s):

The BAL-003-3 Standard Drafting Team (SDT) proposes that the currently-approved Texas RE Regional definition of **Governor** to be made part of the NERC Glossary of Terms generally.

Governor – The electronic, digital or mechanical device that implements Primary Frequency Response of generating units/generating facilities or other system elements.

The BAL-003-3 Standard Drafting Team (SDT) proposes that the currently-approved Texas RE Regional definition of **Primary Frequency Response** to be made part of the NERC Glossary of Terms generally:

Primary Frequency Response – The immediate proportional increase or decrease in real power output provided by generating units/generating facilities in response to system Frequency Deviations. This response is in the direction that stabilizes frequency.

These terms are also used in other standards, as indicated below. The BAL-003-3 SDT is obligated to review other standards in which these terms are used to determine if reliability gaps or redundancies are created by the proposed revision to the defined terms. The BAL-003-3 SDT has determined that the proposed definitions do not change the reliability intent of other requirements or definitions. The following is the standard using the terms Governor and Primary Frequency Response:

BAL-001-TRE – Primary Frequency Response in the ERCOT Region: The BAL-003 SDT determined that the proposed definition revision will not create any redundancies or gaps in reliability.

A. Introduction

1. **Title: Frequency Response and Frequency Bias Setting**

2. **Number:** **BAL-003-~~2~~3**

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

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. ~~Balancing Authority~~Responsible Entity

   4.1.1.1. Balancing Authority

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

   4.1.1.2. Frequency Response Sharing Group

   4.1.2 Generator Operator

   4.1.3 Generator Owner

5. **Effective Date:** See Implementation Plan for BAL-003-3~~2~~.

B. Requirements and Measures

R1. Each Responsible Entity shall achieve an annual ~~Frequency Response Sharing Group (FRSG) or Balancing Authority that is not a member of a FRSG shall achieve an annual~~ Frequency Response Compliance Measure (FRCM) (as calculated and reported in accordance with Attachment A) that is greater than or ~~-~~equal to 1 ~~or more negative than its Frequency Response Obligation (FRO)~~ to ensure that sufficient Frequency Response is provided by each Responsible Entity ~~FRSG or BA that is not a member of a FRSG~~ to maintain Interconnection Frequency Response equal to or more negative than the Interconnection Frequency Response Obligation. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

M1. Each ~~Frequency Response Sharing Group or Balancing Authority that is not a member of a Frequency Response Sharing Group~~ Responsible Entity shall have evidence such as dated data plus documented formula in either hardcopy or electronic format that it achieved an annual FRCM (in accordance with the methods and data specified by the

ERO in Attachment A~~) with data from FRS Form 1 reported to the ERO as specified in Attachment A)~~ that is greater than or equal to 1 ~~or more negative than its FRO~~ to demonstrate compliance with Requirement R1.

R2. Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting shall implement the Frequency Bias Setting determined in accordance with Attachment A, as validated by the ERO, into its Area Control Error (ACE) calculation during the implementation period specified by the ERO and shall use this Frequency Bias Setting until directed by the ERO to change ~~by the ERO~~. *[Violation Risk Factor: Medium][Time Horizon: Operations Planning]*

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

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

3.1 Less than zero at all times, and

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

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

R4. Each Balancing Authority that is performing Overlap Regulation Service shall modify its Frequency Bias Setting in its ACE calculation, in order to represent the Frequency Bias Setting for the combined Balancing Authority Area, to be equivalent to either: *[Risk Factor: Medium][Time Horizon: Operations Planning]*

- The sum of the Frequency Bias Settings ~~as shown on FRS Form 1 and FRS Form 2 for the participating Balancing Authorities~~ as validated by the ERO for the participating Balancing Authorities, or

- The Frequency Bias Setting as validated by the ERO ~~shown on FRS Form 1 and FRS Form 2~~ for the entirety of the participating Balancing Authorities' Areas.

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

R5. Each Balancing Authority shall develop, review and maintain annually, and implement an Operating Process as part of its Operating Plan to determine its Frequency Response requirements and make preparations to have Frequency Response equal to or greater than (in absolute value) the Balancing Authority's Frequency Response Obligation available for maintaining system reliability. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M5. The Balancing Authority will have the following documentation to show compliance with Requirement R5:

- a dated Operating Process;
- evidence to indicate that the Operating Process has been reviewed and maintained annually; and
- evidence, such as Operating Plans or other operator documentation, that demonstrate that the entity determines in its Operating Plans its Frequency Response available and that Frequency Response is equal to or greater than (in absolute value) its Frequency Response Obligation.~~Authority shall have evidence such as a dated operating log, database or list in hard copy or electronic format showing that when it performed Overlap Regulation Service, it modified its Frequency Bias Setting in its ACE calculation as specified in Requirement R4 to demonstrate compliance with Requirement R4.~~

R6. Each Generator Operator shall operate each generating unit/generating facility that is connected to the interconnected transmission system with frequency responsive controls in service when the generating unit/generating facility is online and released for dispatch[1], unless the Generator Operator has notified the Balancing Authority as soon as practical but within 30 minutes of the discovery of a Governor status change (in--service, out--of--service) of a Governor. *[Violation Risk Factor = Medium] [Time Horizon = Real-time Operations]*

[1] That the generator is not being operated in start-up, shutdown, or testing mode pursuant to a Real-time communication or a procedure that was previously provided to the Balancing Authority.

M6. The Generator Operator shall have evidence to show that it notified its associated Balancing Authority any time it failed to operate a generator in the frequency responsive mode when the generating facility was online and released for dispatch.

R7. Each Generator Owner shall have its Governor capability on each resource set with a droop of no more than five (5) percent and a deadband not more than 0.036 Hz. Exceptions to these setting requirements are allowed if the Generator Owner has notified its Balancing Authority that: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

- The droop setting is greater than five (5) percent or the deadband is greater than 0.036 Hz; or
- The resource as designed does not have frequency response capability.

M7. Each Generator Owner shall have evidence that it set its Governor in accordance with Requirement R7. Examples of evidence include, but are not limited to, Governor test reports, Governor setting sheets, performance monitoring reports or documentation that shows the Generator Owner has provided information to the Balancing Authority information to address the exceptions allowed.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: “Compliance Enforcement Authority” means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention: The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The Balancing Authority shall retain data or evidence to show compliance with Requirements R1, R2, R3 and R4 and R5, Measures M1, M2, M3, M4 and M~~4~~5 for the current year plus the previous three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The Frequency Response Sharing Group shall retain data or evidence to show compliance with Requirement R1 and Measure M1 for the current year plus the previous three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- The Generator Operator shall retain evidence of notifications made to the Balancing Authority for the current and previous calendar years for Requirement R6 and Measure M6.
- Each Generator Owner shall retain evidence of its settings for Requirement R7 and Measure M7.
- If a Balancing Authority or Frequency Response Sharing Group is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.
- The Compliance Enforcement Authority shall keep the last audit records and all subsequent requested and submitted records.

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

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

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1.	The ~~Balancing Authority's, or Frequency Response Sharing Group's,~~Responsible Entity's FRCM was less ~~negative~~ than ~~its FRO by at most~~ 100% by at most 15%~~ or 15 MW/0.1 Hz, whichever one is the greater deviation from its FRO~~.	The ~~Balancing Authority's, or Frequency Response Sharing Group's~~Responsible Entity's, FRCM was less ~~negative~~ than 100 % ~~its FRO~~ by more than 15% but by at most 30%~~ or 30 MW/0.1 Hz, whichever is the greater deviation from its FRO~~.	The ~~Balancing Authority's, or Frequency Response Sharing Group's~~Responsible Entity's, FRCM was less ~~negative~~ than 100% ~~its FRO~~ by more than 30% but by at most 45%~~ or 45 MW/0.1 Hz, whichever one is the greater deviation from its FRO~~.	The ~~Balancing Authority's, or Frequency Response Sharing Group's~~Responsible Entity's, FRCM was less ~~negative~~ than 100 % ~~its FRO~~ by more than 45%~~ or by more than 45 MW/0.1 Hz, whichever is the greater deviation from its FRO~~.
R2.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting failed to implement the validated Frequency Bias Setting value into its ACE calculation within the implementation period specified but did so within 5 calendar days from the implementation period specified by the ERO.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting implemented the validated Frequency Bias Setting value into its ACE calculation in more than 5 calendar days but less than or equal to 15 calendar days from the implementation period specified by the ERO.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting implemented the validated Frequency Bias Setting value into its ACE calculation in more than 15 calendar days but less than or equal to 25 calendar days from the implementation period specified by the ERO.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting did not implement the validated Frequency Bias Setting value into its ACE calculation in more than 25 calendar days from the implementation period specified by the ERO.

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

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		validated or calculated value.	validated or calculated value.	The Balancing Authority failed to change the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services.
R5.	The Balancing Authority developed and implemented an Operating Process to determine its Frequency Response requirements and plans to have Frequency Reserve equal to or greater than the Balancing Authority Frequency Response requirements but failed to maintain the Operating Process annually.	N/A	The Balancing Authority developed an Operating Process to determine its Frequency Response requirements and plans to have Frequency Reserve equal to or greater than the Balancing Authority's Frequency Response requirements but failed to implement the Operating Process.	The Balancing Authority failed to develop an Operating Process to determine its Frequency Response requirements and plans to have Frequency Reserve equal to or greater than the Balancing Authority's Frequency Response requirements.
R6.	N/A	N/A	N/A	The Generator Operator did not operate with the frequency responsive controls in service and did not make the required notification within 30 minutes of the discovery of a status change of the frequency responsive controls.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R7.	N/A	N/A	The Generator Owner operated its Governor with droop and/or deadband settings outside those specified and did not notify the Balancing Authority.	The Generator Owner does not have documented Governor settings.

D. Regional Variances

None.

E. Associated Documents

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

~~FRS Form 1~~

~~FRS Form 2~~

Link to the Implementation Plan

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

Version History

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

Version	Date	Action	Change Tracking
1.1	August 25, 2015	Added numbering to Introduction section, corrected parts numbering for R3, and adjusted font within section M4.	Errata
1.1	November 13, 2015	FERC Letter Order approved errata to BAL-003-1.1. Docket RD15-6-000	Errata
2	November 5, 2019	NERC Board of Trustees adopted BAL-003-2	New
2	July 15, 2020	FERC Letter Order approved errata to BAL-003-2. Docket RD20-9-000	
3	November 5, 2019	NERC Board of Trustees adopted BAL-003-3.	Complete Revision under Project 2017-01 Phase II
3	July 15, 2020	FERC Order issued approving BAL-003-3.	

Attachment A

BAL-003-~~2~~3 Frequency Response and Frequency Bias Setting Standard

Supporting Document

Overview of IFRO, FRO, SEFRD, FRM, FRCM, and FBS Calculations

There are several calculations needed to implement the Frequency Response and Frequency Bias Setting Standard. The Interconnection Frequency Response Obligation (IFRO) and Frequency Response Obligation (FRO) calculations are performed by the ERO annually. The Single Event Frequency Response Data (SEFRD), Frequency Response Measure (FRM), Frequency Response Compliance Measure (FRCM), and Frequency Bias Setting (FBS) calculations are performed by the individual BAs and/or FRSGs. The FBS, Most Severe Single Contingencies (MSSCs), and annual load and resource data are submitted by the BAs and evaluated by the ERO. These values are determinants in ERO calculations of IFRO for each interconnection and determination of FRO and minimum FBS for each Balancing Authority.

These calculations are performed at differing points in the annual Operating Year (OY) cycle. The chronology of the determination and use of these calculations is as follows: determination of the IFRO, determination of the individual Balancing Authority FROs and minimum FBSs, publication of frequency events through the OY, determination of SEFRDs, determination of FRM and FRCM, and determination of FBS.

Interconnection Frequency Response Obligation

The ERO, in consultation with regional representatives, has established a target reliability criterion for each Interconnection called the ~~Interconnection Frequency Response Obligation~~ (IFRO). ~~Preliminary~~ Illustrative values for OY 2022 are provided below. Certain values are assessed annually according to the methodology which is detailed in the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*.

Interconnection	**Eastern**	**Western**	**~~ERCOT~~Texas**	**~~HQ~~Quebec**	Units
Max. Delta Frequency (MDF)	**0.420**	**0.280**	**0.405**	**0.947**	
Resource Loss Protection Criteria (RLPC)[1]	**~~3,209~~3,740**	**~~2,850~~3,069**	**~~2,750~~2,805**	**2,000**	MW
Credit for Load Resources (CLR)[1]			**~~1,209~~1,136**		MW
Current IFRO (OY 2022~~18~~)	**-~~1,09~~15**	**-~~858~~1096**	**-~~381~~412**	**-~~179~~211**	MW/0.1 Hz
~~First Step target IFRO~~[1]Estimated Final target IFRO	**-~~915~~890**	**-~~1018~~1096**	**-~~380~~412**	**-211**	MW/0.1 Hz
~~Second Step target IFRO[1, 2]~~	**~~-815~~**				

~~Final target IFRO[1, 2]~~	~~-787~~

Table 1: Interconnection Frequency Response Obligations (base year 2022~~17~~)

IFRO = -(RLPC – CLR)/Max Delta Freq/10

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

   CLR: A load reduction program that meets all of the following requirements shall be utilized by an Interconnection to reduce the IFRO:

   1.1. *1.1 Is requisite to prevent activation of first stage of an Interconnection's Under-Frequency Load Shedding Program (UFLS) for any resource loss less than or equal to the Interconnection's Resource Loss Protection Criteria (RLPC);*

   1.2. *Is non-proportional and automatically activated;*

   1.3. *Activates within 1 (one) second of the trigger frequency being reached;*

   1.4. *Exclusively reserved for Frequency Response during normal operations and does not participate in UFLS, Undervoltage Load Shedding (UVLS), or any other Ancillary Service, such as Contingency Reserve, and is not used for any other operator-initiated normal operations; and*

   1.5. *Available at least 95% of the time and is reviewed as part of the ERO analysis that determines the IFRO.*

Annual reductions

~~T~~to an ~~reduce risk, the Eastern I~~interconnection's IFRO due to a change to the RLPC, CLR and/or the Maximum Delta Frequency (MDF) will be limited to no greater than 10 percent of the existing~~stepped down annually from the 2017 value of -1,015 MW/0.1 Hz in -100 MW/0.1 Hz increments. If during the step down process, I~~interconnection's IFRO or -100MW/.10Hz, whichever is less negative. Multiple year reductions may be necessary to meet the final target IFRO. If during the step-down process the Interconnection's ~~Frequency Response Measure~~ (FRM) as calculated by ~~declines by more than 10 percent,~~ the ERO declines by more than 10 percent, the ERO will ~~halt~~delay ~~the~~ subsequent reduction in IFRO until such time that a determination can be made as to the cause of the ~~degradation~~disproportionate performance.

Balancing Authority Frequency Response Obligation ~~and Frequency Bias Setting~~

For a multiple Balancing Authority interconnection, the I~~nterconnection~~ FRO shown in Table 1 is allocated based on the Balancing Authority annual load and annual generation as measured in MWh. The ~~FRO~~ allocation of IFRO to determine the FRO for each BA is calculated using the ~~will be based on the~~ following ~~method~~formula:

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

Where:

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

Balancing Authorities that form, merge or transfer load or resource must notify the ERO of the change in footprint and corresponding changes in allocation prior to the change such that the net obligation to the Interconnection remains the same and so that FBS and FRO can be adjusted.

Annually, the ERO reviews the load and resource data submitted for all Balancing Authorities for each Interconnection in the format requested by the ERO. After such annual review, the ERO will post the following information for each Balancing Authority for the upcoming year:

- Minimum FBS
- FRO

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

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

Frequency Event Selections and Postings

The OY annual list of events for each interconnection are selected by the ERO using the Procedure for ERO Support of Frequency Response and FBS Standard. Events that trigger UFLS will not be selected as BAL-003 events. The ERO will publish the annual list for each interconnection in accordance with the timeline below. If the ERO posts the official list of events after the date specified in the timeline below, Balancing Authorities and FRSG(s) will be given 30 days from the date the ERO posts the official list of events to submit the required data.

ERO Posting and Data Submittal Form

The ERO shall alert responsible entities each year of the appropriate method for data submittal, including for example, a Section 1600 Data Request for Information under the Rules of Procedure, if approved by the NERC Board of Trustees.

The ERO publication of the official list of events is included in the form to be used for annual data submittal. The submittal includes data needed for the determination of Interconnection RLPCs and IFROs, as well as calendar year Balancing Authority specific data needed for determination of the respective Balancing Authorities' FROs and minimum bias settings.

Interconnection RLPC and Minimum Bias Data Submittal Data Items:

- Largest potential resource loss within the Balancing Authority Area for the next ~~o~~Operating ~~y~~Year as detailed in the "Procedure for ERO Support of Frequency Response and Frequency Bias Settings Standard"
- Second largest potential resource loss within the Balancing Authority Area for the next ~~o~~Operating ~~y~~Year as detailed in the "Procedure for ERO Support of Frequency Response and Frequency Bias Settings Standard"
- The largest resource loss within the Balancing Authority Area that results from a RAS action initiated by a multiple contingency (N-2) event as detailed in the "Procedure for ERO Support of Frequency Response and Frequency Bias Settings Standard"
- CLR – this value will be used to adjust the Interconnection IFRO
- Balancing Authority Area resource (MWh) for the previous calendar year – this value will be used in the formula described above to determine the BA FRO
- Balancing Authority Area Net Energy for load (MWh) for the previous calendar year – this value will be used in the formula described above to determine the BA FRO
- Balancing Authority Area Integrated Hourly Peak load (MW) for the previous calendar year – this value will be used to determine the minimum (in absolute value) bias setting. The (absolute value) minimum is 0.9% of the annual BA peak load.

Desired FBS - may be set to a value between 100% to 125% of the Balancing Authority FRM if this value is more negative than the minimum Frequency Bias based on Peak Demand. If not more negative, then the Frequency Bias must be the minimum Bias based on Peak Demand.

For Balancing Authorities which supply or receive Overlap Regulation Service, the partnered Balancing Authority and the amount of overlap are to be provided.

The ERO submittal form also is used to collect data for each event as described in the following sections.

Single Event Frequency Response Data

The Balancing Authority will calculate its FRM and FRCM values from SEFRD, defined as: "the data from an individual event in a Balancing Authority area that is used to calculate its Frequency Response, expressed in MW/0.1Hz."

The SEFRD needed for evaluation is, at a minimum, the following Balancing Authority's Energy Management System (EMS) scan rate data items for the period 1 minute prior through 5 minutes after the ERO-supplied event time (t0):

- Actual frequency (F_A)
- Net Interchange Actual (N_{AI}) – for single BA interconnections, this value may be zero (0)
- Net resource or load loss – for single Balancing Authority interconnections, this value is needed for each event; for multiple Balancing Authority interconnections, this value is only to be reported by the Balancing Authority (or pro rata by multiple Balancing Authorities if a jointly owned unit) which sustained the resource loss. Lost load values are to be specified as a negative amount; lost resource values are to be specified as a positive amount.

Balancing Authorities may choose to apply certain adjustments to their calculations to account for factors such as nonconforming loads. For any such adjustments used, the SEFRD shall include the EMS scan rate data for the period 1 minute prior to through 5 minutes after the ERO-supplied event time (t0). The types of adjustments that are allowed are:

- non-conforming loads (load values specified as a negative amount),
- pumped hydro operation (load values specified as a negative amount, resource values specified as a positive amount),
- jointly owned unit dynamic schedules (import values specified as a negative amount, export values specified as a positive amount), and
- transferred frequency response (receipt values specified as a negative amount, delivered values specified as a positive amount).

For each of these adjustments, a given adjustment must be made for either all events or none of the events in an evaluation year.

All events provided by the ERO need to be included in the annual evaluation to determine the annual FRCM. A Balancing Authority may exclude an event only if, during any part of the event evaluation period:

- its tie-line data or its Frequency data was corrupt,
- its EMS was unavailable, or
- its Balancing Authority was completely islanded from the remainder of the interconnection.

Determination of Balancing Authority Event Time (t_0) and Data Alignment

Because a particular BA's EMS scan can occur anywhere within a 2-- to -6- second window, the ERO specified event time (t_0) may not exactly align with a given BA's EMS scan. For each event, the Balancing Authority must review its frequency scan data and determine the last frequency scan prior to the frequency deviation (decline for a resource loss, spike for a load loss). The Balancing Authority should set the time of that scan as the Balancing Authority's event time (t_0) for that event. The time of the Balancing Authority's event time (t_0) should be within one scan of the frequency deviation.

In addition to the determination of the Balancing Authority's t_0, a review of the other data items collected should be made to determine if a time shift is needed ~~of~~for any of these items relative to the times of the frequency scans. These shifts may be needed due to data transfer lags (e.g., dynamic signals transferred between Balancing Authorities via ICCP). If such a shift is needed, data item scans should be shifted to align to the times of the frequency scans.

Determination of the pre-event sample period (commonly known as the A space) and the post-event sample period (commonly known as the B space) shall be measured from the Balancing Authority determined event time (t_0).

Single Event Frequency Response Measure

Pre-event values (A value scans) for each data item used (actual frequency, net actual interchange, contingency loss, non-conforming loads, pumped hydro operation, jointly owned unit dynamic schedules, and/or transferred frequency response) will be the EMS data scans over the 16-second period before the Balancing Authority's event time (t_0) up to but excluding the Balancing Authority's event time (t_0).

The A value will be the average of the selected scans for that item. For low frequency events, the pre-event frequency value (frequency A value) will be calculated as the minimum of 60.000 Hz or average actual starting frequency. For high frequency events, the pre-event frequency value (frequency A value) will be calculated as the maximum of 60.000 Hz or average actual frequency.

Post-event (B value scans) for each data item used will be the EMS data scans over 20 to 52 seconds after the Balancing Authority's event time (t0). For each item used, the B value for that item will be the average of the selected scans for that item.

The number of scans for each average value in the computation of A and B values will be dependent on the data scan rate of the Balancing Authority's EMS. Calculation of the A value should contain data from at least three distinct time points and the calculation of the B value should contain data from at least five distinct time points.

The pre-event MW value is the average of the A values (scan values) of all of the data items (except frequency) used. Each of the data items must use the sign convention as noted in the listings above. Similarly, the post-event MW value is the average of the B values (scan values) of all of the data items (except frequency) used, again using the appropriate sign convention for each item.

The total MW change is determined by subtracting the average post-event MW value from the average pre-event MW value. Similarly, the frequency change is determined by subtracting the average post-event frequency value (frequency B value) from the average pre-event frequency value (frequency A value).

The Single Event Frequency Response Measure (event FRM) is determined by dividing the total MW change by the total frequency change.

If a Balancing Authority uses the transferred frequency response adjustment, an additional calculation will be needed. BAs will need to calculate the event FRMs without incorporating transferred frequency response adjustments. This "FRM w/o Trfr" value is needed to calculate the Balancing Authority's Bias Setting, but it is not used to calculate the Balancing Authority's event FRCMs. The event FRMs including transferred frequency response are the values used to calculate event FRCMs.

Single Event Frequency Response Compliance Measure

The FRCM for each event is the ratio of FRM to FRO (FRM divided by FRO).

For FRSGs, the FRSG FRM for each event is calculated by dividing the sum the active Balancing Authorities' FRMs by the sum of the active Balancing Authorities' FROs. If a Balancing Authority is an FRSG participant and meets the requirements for excluding an event, e.g. loss of telemetry during event, the FRSG shall exclude the Balancing Authority's FRO and FRM from the FRSG's calculation of FRCM for the excluded event. For any event in which more than 50% of the Balancing Authority participants' data is excluded, the FRSG shall exclude that event for the FRSG.

Annual (OY) Frequency Response Measure and Frequency Response Compliance Measure

The Balancing Authority's FRM for the OY is determined by taking the median of the individual event FRM values.

The Balancing Authority's FRCM for the OY is determined by taking the median of the individual event FRCM values. An FRSG or a Balancing Authority providing Overlap Regulation Service will provide individual event FRCMs for the aggregate of its active participants.

Balancing Authority Fixed Frequency Bias Setting

A Balancing Authority in an Interconnection with multiple Balancing Authorities using a fixed FBS sets its FBS to the more negative value than:

- Any number the Balancing Authority chooses between 100 percent and 125 percent of its Frequency Response Measure
- Balancing Authority Minimum Frequency Bias Setting as determined by the ERO

Balancing Authority Variable Frequency Bias Setting

A Balancing Authority in an Interconnection with multiple Balancing Authorities using a ~~fixed~~variable FBS sets its FBS such that it is:

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

Balancing Authority and Frequency Response Group Reporting

Each Balancing Authority reports its previous year's FRM (both with and without transferred frequency response adjustment), FRCM Frequency Bias Setting and Frequency Bias type (fixed or variable) to the ERO each year to allow the ERO to validate the revised FBS. In addition, each Balancing Authority will report its two largest potential resource losses and any applicable N-2 RAS events in the format specified by the ERO.

- Once the data listed above is fully posted, the ERO will announce the implementation period for changing the FBS.~~Calculate a group NI_A and measure the group response to all events in the reporting year on a single FRS Form 1, or~~
- ~~Submit a joint Form 1 with the "FRSG" tab completed for the aggregate performance of the participating Balancing Authorities.~~

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

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

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

- ~~Frequency Bias Setting~~
- ~~Frequency Response Obligation (FRO)~~

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

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

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

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

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

~~**Frequency Response Measure**~~

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

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

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

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

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

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

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

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

Timeline for Balancing Authority Frequency Response and Frequency Bias Setting Activities

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

- Facilitate the assignment of Balancing Authority FRO
- Calculate Balancing Authority FRCM
- Determine Balancing Authority F~~requency~~ B~~ias~~ S~~ettings~~

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

* If the 4th quarter posting of events for evaluation of FR~~S~~M and FRCM ~~Form 1s~~ is delayed, the ERO may adjust the other timelines in this table ~~by a similar amount~~.

** Data specification~~Procedure~~ will be maintained on the ~~for~~ ERO website; for example Procedure for ERO Support of Frequency Response and Frequency Bias ~~Setting~~ Standard or its successor.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Industry Outreach

Project 2019-04 Modifications to PRC-005

Giuseppe Giannuzzi, P. Eng. (SDT Member)
Hydro-Québec

December 8, 2022

RELIABILITY | RESILIENCE | SECURITY




Agenda

Agenda

- Project Background
- Reliability Standard PRC-005-6 Revisions
- Next Steps
- Q&A

Special thanks to Laura Anderson for the preparation of this Industry Outreach presentation

Standard Drafting Team

Name	Entity
Brian Kasmarzik	Quanta-Technology
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Michael Gerken	Eversource
Giuseppe Giannuzzi	Hydro-Québec
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Cesar Huerta	AEP
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Randy Rhinier	Duke Energy
Sudhir Thakur	Constellation
Kevin Thompson	ITC
Devon Tremont	Taunton Municipal Lighting Plant
Zhibo Wang	BC Hydro

Background

- Background
  - In June of 2016, Xcel Energy submitted a Request for Interpretation (RFI) to NERC seeking clarification on what equipment should be included in the scope of an entity's Protection System Maintenance Program relative to NERC Reliability Standard PRC-005-6. Xcel Energy noted that many modern generator excitation systems have the capability to respond to electrical quantities and initiate trip signals to either the generator lockout or generator output breaker. Xcel Energy asked whether a protection function (if enabled) that is embedded in a generator's excitation system or voltage regulator would meet the definition of Protection System, and therefore be included in the scope of PRC-005-6. The RFI was rejected by the NERC Standards Committee at the recommendation of NERC staff, the standards developer, and leadership of the PRC-005-6 drafting team (DT) for the following reason:

Background

- *"The generator excitation systems and voltage regulators described in Xcel Energy's RFI are capable of monitoring electrical quantities, such as voltage or current, and responding to those quantities, by causing a trip of the generator in response to these signals. Therefore, it is clear that these embedded protective functions, if enabled, would be included in the scope of Reliability Standard PRC-005-6 as set out in the Applicability section of the standard."*

- Despite this perceived clarity, the North American Generator Forum (NAGF) received feedback from members indicating that significant confusion still remains throughout the industry regarding the applicability of protective functions inside synchronous generator excitation systems to PRC-005. Consequently, in May 2019, the NAGF submitted a Standard Authorization Request (SAR) to NERC requesting revisions be made to PRC-005-6 that would provide clear and unambiguous language within the standard pertaining to the applicability of protective functions within an Automatic Voltage Regulators (AVR) and any maintenance requirements (activities and intervals) associated with those protective functions.

Background

- In response to industry comments received from three postings of the SAR, the Standard Drafting Team has considered the following in modifying PRC-005-6:
  - Clarify that BES protective functions enabled within analog/digital AVRs, excitation systems, and BES protective functions enabled within 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, and include updates to associated maintenance tables as necessary.
  - Include new DC supplies (e.g., lithium ion, flow) for Protection Systems in the maintenance tables.
  - Include entities registered as UFLS-Only Distribution Providers in the Applicability section to be consistent with changes made to the NERC's FERC-approved Risk-Based Registration.

Background

- Update the PRC-005-6 Supplementary Reference and FAQ to align with all revisions made to the standard.
- Revise the Applicability section of the standard.

PRC-005-6 Revisions

- The Standard Drafting Team recognized the need to modify the definition of Protection System.
- Modifications are necessary to provide clarity on the inclusion of components of control systems which measure and utilize similar quantities as protective relays and perform similar functions as protective relays.

PRC-005-6 Revisions

- The working draft of the proposed new definition of Protection System is (one or more of the following components):
  - Protective relays, or components of control systems, which respond to measured electrical quantities and provide protective functions;
  - Communications systems necessary for correct operation of protective functions;
  - Voltage and current sensing devices providing inputs necessary for the correct operation of protective functions;
  - Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply); or
  - Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

PRC-005-6 Revisions

- Measured Electrical Quantities
  - The Standard Drafting Team recognized the need for clarity in the phrase “respond to electrical quantities” due to the fact that nearly all measured quantities are converted to electrical signals prior to input into protection and control systems.
  - Measured electrical quantities are those that represent Primary AC or DC voltage and current for applicable Facilities, such as:
    - Generating unit terminal voltage and current,
    - Excitation voltage.
  - Included are any quantities derived from voltage and current measurements, such as:
    - Frequency,
    - Real and Reactive Power, and
    - Phase angles.

PRC-005-6 Revisions

- Protective Functions
  - The SDT used the following criteria to establish which functions meet the criteria of protective functions for inclusion in the definition:
    - Functions that are implemented to initiate or prevent the automatic isolation of Facilities:
      - To protect power system Elements,
      - To maintain stability, or
      - In response to detected faults.
  - Functions not applicable to the definition include those which do not initiate or prevent automatic isolation, such as:
    - Limiters or functions which only provide indication; or
    - Devices which do not respond to the aforementioned scenarios, such as:
      - those detecting malfunctions of an excitation system, or
      - automatic switching of capacitor banks for the purpose of voltage-control.

PRC-005-6 Revisions

- Evaluation of Functions
  - The SDT performed an analysis of IEEE device numbers using the criteria above as an example of the analysis to determine which functions should be considered for inclusion in Protection Systems.
  - The results of the example analysis were consistent with the analysis performed by the SPCWG in *SPCS Order 758 Sudden Pressure Relay Report,* which was performed in response to FERC Order No. 758 to determine which protective functions not included in the Protection System definition should be considered for inclusion in PRC-005.
  - A list of all IEEE device numbers, including a description of each device, is included in Appendix A.
  - Each device was evaluated to determine applicability, the results of which can be seen in Appendix B.

1.IEEE Standard C37.2, 2008

Next Steps

- Collaborate with Project 2021-01 Modifications to MOD-025 and PRC-019 regarding defining "Protection System."
- SDT meetings schedule TBD
- February 2023 Standards Committee to request approval for 45-day initial comment period with 10-day ballot.
- Point of Contact
  - Laura Anderson, Standards Developer
    - laura.anderson@nerc.net or call 404-446-9671

Questions and Answers

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 an additional 45-day formal comment period with ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	March 18, 2020
SAR posted for comment	April 8, 2020
45-day formal comment period with ballot	April 26 – June 9, 2021
55-day formal comment period with ballot	November 2021

Anticipated Actions	Date
45-day formal comment period with ballot	October 2022
10-day final ballot	December 2022
Board adoption	February 2023

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-~~1~~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-~~1~~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-~~1~~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 ~~of~~, 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 protection~~method(s) used to mitigate the risks posed by unauthorized disclosure and unauthorized modification 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~~method(s) used to mitigate the ~~Responsible Entity applied security protection~~risk(s) posed by loss of data used for ~~transmitting~~ Real-time Assessment and Real-time monitoring while such data is being transmitted between Control Centers;

1.3. Identification of method(s) used to recover communication links used to transmit Real-time Assessment and Real-time monitoring data between Control Centers;

~~1.2.~~1.4. Identification of where the Responsible Entity implemented method(s) as required in Parts 1.1 and 1.2; and

~~1.3.~~1.5. If the Control Centers are owned or operated by different Responsible Entities, identification of the responsibilities of each Responsible Entity for ~~applying security protection to the transmission of Real-time Assessment and Real-time monitoring data between those Control Centers.~~ implementing method(s) as required in Parts 1.1 and 1.2.

~~Evidence~~

M1. Examples of evidence may include, but ~~is~~are not limited to, documented plan(s) that meet the ~~security~~mitigation objective of Requirement R1 and documentation demonstrating the implementation of the plan(s).

Part 1.1

- identification of points where the encryption/decryption of the data occurs at either a transport, network, or application layer
- physical access restrictions to unencrypted portions of the network

Part 1.2

- network diagram showing redundancy of paths between Control Centers
- procedures explaining the use of alternative systems or methods for providing for the availability of the data
- service level agreements with carriers containing high availability provisions
- availability or uptime reports for equipment supporting the transmission of Real-time Assessment and Real-time monitoring data

Part 1.3

- Contract, memorandum of understanding, meeting minutes, agreement or other information outlining the methods used for recovery
- Methods for the recovery of links such as standard operating procedures, CIP-009 recovery plan(s), or similar technical recovery plans

- Documentation of the process to restore assets and systems that provide communications

Part 1.4

- Descriptions or logical diagrams indicating where the implemented methods reside
- Identification of points within the infrastructure where the implemented methods reside
- Agreements outlining the implemented methods if provided by a third party

Part 1.5

- Contract, memorandum of understanding, meeting minutes, agreement or other documentation outlining the responsibilities of each entity

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 its plan(s) for Requirement R1; Or The Responsible Entity failed to implement ~~any Part~~three or more Parts of its plan(s) for Requirement R1, except under CIP Exceptional Circumstances.

D. Regional Variances

None.

E. Associated Documents

- Implementation Plan.
- Technical Rationale for CIP-012-~~1.~~2.

~~Implementation Guidance.~~

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;	
1	February 17,2020	Effective Date	7/1/2022
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

This is the first draft of the proposed standard for a formal 45-day comment period.

Completed Actions	Date
Standards Committee approved Standards Authorization Request (SAR)	September 24, 2020
SAR posted for comment	December 16, 2020 – January 14, 2021
~~**Anticipated Actions**~~	~~**Date**~~
45-day initial formal comment period with ballot	May 20 – July ~~5~~6, 2022
45-day additional formal comment period with ballot	~~October –~~ November 21, 2022 – January 18, 2023

Anticipated Actions	Date
10-day final ballot	~~December 2022~~January 2023
NERC Board adoption	~~February~~ May 2023

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:** Verification of Dynamic Models and Data for BES Connected Facilities

2. **Number:** MOD-026-2

3. **Purpose:** To verify that the dynamic models and associated parameters used to assess Bulk Electric System (BES) reliability represent the in-service equipment of BES Facilities including generating Facilities, transmission connected dynamic reactive resources, and high-voltage direct current (HVDC) terminal equipment.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Generator Owner

   4.1.2. Transmission Planner

   4.1.3. Planning ~~Authority~~ Coordinator

   4.1.4. Transmission Owner that owns a Facility listed in Section 4.2.4 or 4.2.5

   4.2. Facilities: For the purpose of this standard, the term "applicable ~~units~~Facility" or "Facility" shall mean any one of the following:

   4.2.1 Individual generating ~~resource identified through~~ unit meeting the criteria set by Inclusion I2 of the BES definition.

   4.2.2 Generating plant/Facility ~~identified through~~ meeting the criteria set by Inclusion I2 of the BES definition.

   4.2.3 Generating plant/Facility of dispersed power producing resources ~~identified through~~ meeting the criteria set by Inclusion I4 of the BES definition.

   4.2.4 Dynamic reactive resources ~~identified through~~ meeting the criteria set by Inclusion I5 of the BES definition with a gross (individual or aggregate) nameplate rating greater than 20 MVA including, but not limited to:

   4.2.4.1 Synchronous condenser; and

   4.2.4.2 Flexible alternating current transmission system (FACTS) devices.

   4.2.5 HVDC terminal equipment including:

   4.2.5.1 Line commutated converter (LCC); and

   4.2.5.2 Voltage source converter (VSC).

5. **Effective Date:** See Project 2020-06 Verification of Dynamic Models and Data for BES Connected Facilities Implementation Plan

~~**6. Standard-Only Definitions:**~~

~~**6.1.** Verification refers to the static process of checking documents and files, and comparing them to model parameters, model structure, or equipment settings.~~

~~**6.2.** Validation refers to the dynamic process of testing or monitoring the in-service equipment behavior, and then using the testing or monitoring results and comparing them to the model simulated response.~~

B. Requirements and Measures

R1. Each Transmission Planner and its Planning ~~Authority~~ Coordinator, shall jointly develop dynamic model verification[1] requirements and processes. The dynamic model verification requirements and processes shall be made available to the Generator Owner and Transmission Owner by the Transmission Planner, and include at a minimum the following: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

1.1. Acceptable positive sequence dynamic models, format, and level of detail;

1.2. Acceptable electromagnetic transient (EMT) models, format, and level of detail~~[1]~~;[2]

1.3. Acceptance criteria used by the Transmission Planner to determine disposition ~~in~~ under Requirement R8 including~~-~~, at a minimum~~-~~, the following:

1.3.1. model parameterization checks;

1.3.2. model usability, initialization, and interoperability; and

1.3.3. model submittal requirements.~~[2]~~[3]

1.4. Process for Generator Owner or Transmission Owner to provide verified models to the Transmission Planner;

1.5. Process by which verified model(s) are submitted to the applicable Planning ~~Authority~~Coordinator, after the model(s) meets acceptance criteria of Part 1.3; and

1.6. Process for Generator Owner or Transmission Owner to obtain the model(s) contained in the Transmission Planner's database for an existing Facility owned by the Generator Owner or Transmission Owner within 90 days of receiving a written request.

M1. Each Transmission Planner and each Planning ~~Authority~~ Coordinator must provide dated evidence such as document(s), webpage(s), or web portal(s) outlining the model

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[1] For the purposes of this Reliability Standard, the term "verification" refers to the static process of checking documents and files, and comparing them to model parameters, model structure, or equipment settings.

~~[1] Detailed EMT modeling requirements are developed by the Transmission Planner to ensure consistent EMT models are provided based on the types of studies being performed and the specific EMT simulation tools being used.~~

[2] Detailed EMT modeling requirements are developed by the Transmission Planner to ensure consistent EMT models are provided based on the types of studies being performed and the specific EMT simulation tools being used.

~~[2]~~[3] Model submittal requirements needed by the Transmission Planner may include, but are not limited to, required data files and inclusions needed in the model report.

requirements and processes that are jointly developed. Each Transmission Planner shall also have evidence showing it made available to the Generator Owner ~~or~~ and Transmission Owner the model requirements and processes in accordance with Requirement R1.

Synchronous Facility

R2. For synchronous generation identified in Section 4.2.1 or 4.2.2 or a synchronous condenser identified in Section 4.2.4.1, each Generator Owner or Transmission Owner shall provide a verified positive sequence dynamic model(s)~~,~~ with associated parameters, and accompanying information that represent the in-service equipment of the Facility to its Transmission Planner, in accordance with ~~the periodicity in~~ MOD-026-2 Attachment 1. The verified model(s) and accompanying information shall include at a minimum the following: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. Manufacturer, model number (if available), and type of generator/synchronous condenser, excitation system hardware, and Protection System(s) ~~of~~ specified in Part 2.3;

2.2. Model(s) representing the generator/synchronous condenser, and associated excitation system including voltage regulator, impedance compensation, power system stabilizer, ~~excitation limiters,~~ and outer-loop controls which impact dynamic volt/volt-ampere reactive (VAR) performance;

2.3. Model(s) representing enabled excitation limiters and enabled Protection Systems that directly trip the prime mover or generator/synchronous condenser. Protection Systems that shall be modeled include phase over- and under-voltage, stator ~~and~~ -phase overcurrent, voltage restrained time overcurrent, field overcurrent, loss of field, out-of-step, phase-distance, and volts per hertz protection; and

2.4. Validation[4] of the positive sequence dynamic model(s) of Part 2.2 response using the recorded response for a dynamic ~~volt or VAR~~ reactive power or voltage event from either a staged test or a measured system disturbance.

M2. Each Generator Owner or Transmission Owner must provide dated evidence for each applicable ~~unit~~ Facility that model(s) were verified in accordance with Requirement R2 and that it provided the verified model(s) and accompanying information to its Transmission Planner in accordance with the periodicity.

R3. For synchronous generation identified in Section 4.2.1 or 4.2.2, each Generator Owner shall provide a verified positive sequence dynamic model(s)~~,~~ with associated parameters, and accompanying information that represent the in-service equipment of the Facility to its Transmission Planner, in accordance with ~~the periodicity in~~ MOD-026-2 Attachment 1. The verified ~~model(s)~~model(s) and accompanying information

[4] For the purposes of this Reliability Standard, the term "validation" refers to the dynamic process of testing or monitoring the in-service equipment behavior, and then using the testing or monitoring results and comparing them to the model simulated response.

shall include at a minimum the following: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Manufacturer, model number (if available), type of ~~turbine~~prime mover, type of governor, ~~mode of operation~~type of control, and Protection System(s) of Part 3.3;

3.2. Model(s) representing the ~~turbine~~prime mover, governor control system, ~~load controller, and other outer loop controls that override the governor response or modes of operation that limit frequency response~~and any other controls which impact the dynamic active power or frequency performance due to a system disturbance (e.g. load controller), but excluding automatic generation control;

3.3. Model(s) representing enabled Protection Systems that directly trip the ~~turbine~~ prime mover or generator. Protection Systems that shall be modeled include over- and ~~under-speed, and over- and~~ under-frequency elements. In addition, model(s) representing enabled prime mover over- and under-speed trip functions that directly trip the prime mover/generator; and

3.4. Validation of the positive sequence dynamic model(s) of Part 3.2 response using the recorded response for a dynamic active power or frequency event from either a staged test or a measured system disturbance in which perceived frequency deviates per Attachment 1, Note 1.

M3. Each Generator Owner or Transmission Owner must provide dated evidence for each applicable ~~unit~~ Facility that model(s) were verified in accordance with Requirement R3 and provided the verified model(s) and accompanying information to its Transmission Planner in accordance with the periodicity.

Inverter Based Resource Facility

R4. For inverter based resources (IBRs) identified in Section 4.2.3, FACTS devices identified in Section 4.2.4.2, and VSC HVDC identified in ~~section~~ Section 4.2.5.2, each Generator Owner or Transmission Owner shall provide a verified positive sequence dynamic model(s)~~,~~ with associated parameters, and accompanying information that represent the in-service equipment of the Facility to its Transmission Planner, in accordance with ~~the periodicity in~~ MOD-026-2 Attachment 1. The verified ~~model(s)~~model(s) and accompanying information shall include at a minimum the following: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Manufacturer, model number, and software/firmware version number of the IBR unit(s)[~~3~~5] and power plant controller;

4.2. Model(s) representing the IBR unit(s), and associated reactive power control system[~~4~~6] including the IBR unit's electrical control, power plant controller, auxiliary reactive resources, and other equipment which impacts plant voltage and reactive power dynamic response;

[~~3~~5] IBR unit includes the inverter, converter, wind turbine generator, or HVDC converter.

[~~4~~6] Reactive power control system includes voltage reference control, reactive power reference control, and power factor control modes.

4.3. Model(s) representing enabled protections[~~5~~7] and limiting functions,[~~6~~8] that either directly trip IBR unit(s) or plant, or limit active/reactive output of the IBR unit or plant; and

4.4. Validation[9] of the positive sequence dynamic model(s) of Part 4.2 response using the recorded response for a dynamic ~~volt or VAR~~ reactive power or voltage event from either a staged test or a system disturbance.

M4. Each Generator Owner or Transmission Owner must provide dated evidence for each applicable ~~unit~~ Facility that model(s) were verified in accordance with Requirement R4 and provided the verified model(s) and accompanying information to its Transmission Planner in accordance with the periodicity.

R5. For inverter based resources (IBRs) identified in Section 4.2.3, LCC HVDC identified in Section 4.2.5.1, and VSC HVDC identified in Section 4.2.5.2, each Generator Owner or Transmission Owner shall provide a verified positive sequence dynamic model(s)~~,~~ with associated parameters, and accompanying information that represent the in-service equipment of the Facility to its Transmission Planner, in accordance with ~~the periodicity in~~ MOD-026-2 Attachment 1. The verified ~~model(s)~~model(s) shall include at a minimum the following: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

5.1. Manufacturer, model number, and software/firmware version number of the IBR unit(s), power plant controller;

5.2. Model(s) representing the IBR unit(s), and associated active power/frequency control including the IBR unit's electrical control, power plant controller, and other equipment which impacts plant active power or grid frequency dynamic response;

5.3. Model(s) representing enabled protections[~~7~~10] and limiting functions, that either directly trip IBR unit(s) or plant, or limit active/reactive output of the IBR unit or plant; and

5.4. Validation of the positive sequence dynamic model of Part 5.2 response using the recorded response for a dynamic active power or frequency event from either a staged test or a measured system disturbance in which the power plant controller's or other Facility active power controller's perceived frequency deviates per Attachment 1, Note 1.

M5. Each Generator Owner or Transmission Owner must provide dated evidence for each applicable ~~unit~~ Facility that model(s) were verified in accordance with Requirement R5 and provided the verified model(s) and accompanying information to its Transmission Planner in accordance with the periodicity.

[~~5~~7] Protection functions that shall be modeled include at a minimum ~~ac~~ AC over- and under-voltage protection.

[~~6~~8] Limiting functions include active/reactive power limiting, active/reactive current limiting, or other limiting functions as may be involved in active/reactive power prioritization and disturbance ride-through.

[9] For the purposes of this Reliability Standard, the term "validation" refers to the dynamic process of testing or monitoring the in-service equipment behavior, and then using the testing or monitoring results and comparing them to the model simulated response.

[~~7~~10] Protection functions that shall be modeled include at a minimum over- and under-frequency protection.

R6. For ~~applicable units of~~ inverter based resources (IBRs) ~~per~~ identified in Section 4.2.3, FACTS devices per Section 4.2.4.2, LCC HVDC ~~per~~ identified in Section 4.2.5.1, and VSC HVDC ~~per~~ identified in 4.2.5.2, each Generator Owner or Transmission Owner shall provide a verified EMT model(s)~~,~~ with associated parameters~~,~~ and accompanying information that represent the in-service equipment of the Facility to its Transmission Planner, in accordance with ~~the periodicity in~~ MOD-026-2 Attachment 1. The verified ~~model(s)~~model(s) and accompanying information shall include at a minimum the following: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

6.1. Attestation from respective original equipment manufacturer(s) (OEM) stating the structure of IBR unit model(s), power plant controller model, and auxiliary control devices model(s) represent the equipment supplied by the OEM.[~~8~~11] If an attestation from an OEM is not obtainable, the Generator Owner or Transmission Owner shall document the reason;

6.2. Device test[~~9~~12] results demonstrating a comparison of the IBR unit's response and the IBR unit's EMT model response for large signal disturbances. If device test results are not obtainable, the Generator Owner or Transmission Owner shall document the reason;

6.3. Facility EMT model ~~and~~ with associated parameters representing the IBR unit(s), collector system, auxiliary devices, power plant controller, main transformer(s), and enabled protections and controls that either directly trip IBR unit(s) or plant, or limit active/reactive output of the IBR unit or plant;[~~10~~13]

6.4. Validation of the Facility EMT model response using the recorded response for a dynamic ~~volt or VAR~~ reactive power or voltage event,[~~11~~14] and for a dynamic active power or frequency event in which the power plant controller's or other Facility active power controller's perceived frequency deviates per Attachment 1, Note 1, resulting from either a staged test or a system disturbance; and

6.5. Documentation comparing the response of positive sequence dynamic model(s) of Requirement R4 and R5 to the response of Facility EMT model of Requirement R6 for large signal disturbances.

M6. Each Generator Owner or Transmission Owner must provide dated evidence for each applicable ~~unit~~ Facility that model(s) were verified in accordance with Requirement R6 and provided the verified model(s) and accompanying information to its Transmission Planner in accordance with the periodicity.

[~~8~~11] The attestation shall include the equipment make, model number, software/firmware version number, and confirmation that all inverter control modes, control blocks, and protections are represented in the model.

[~~9~~12] A device test that is hardware specific may include a factory type test, hardware in the loop test, or other ~~manufacture~~ manufacturer test to ensure the EMT model's large signal response emulates the supplied equipment to the extent possible.

[~~10~~13] Enabled protections and controls that act on voltage, frequency, and/or current, or act on quantities derived from voltage, frequency, and/or current, which directly trip the IBR unit(s) or plant, or limit active/reactive output of the IBR unit or plant. Examples of protections include IBR unit DC reverse current, DC bus over- and under-voltage, DC voltage unbalance, DC overcurrent, AC over- and under-voltage protection (instantaneous and RMS), AC overcurrent, over- and under-frequency protection, feeder (equivalent) AC over- and under-voltage, feeder (equivalent) over- and under-frequency, PLL (or equivalent) loss of synchronism, and phase jump tripping.

[~~11~~14] LCC HVDC facilities are excluded from the dynamic voltage or VAR event portion of the requirement.

General Requirements

R7. Each Generator Owner or Transmission Owner shall provide an updated verified model(s)~~,~~, or a ~~mutually agreed upon~~ plan ~~with its Transmission Planner~~ to verify the model~~(s)~~(s), in accordance with one or more of Requirements ~~R2–R6~~ R2, R3, R4, R5, or R6[~~12~~15] to its Transmission Planner within 180 calendar days of making a hardware, software, firmware, control mode, or setting change to in-service equipment specified in Part 2.2, 2.3, 3.2, 3.3, 4.2, 4.3, 5.2, 5.3, or 6.3 that alters the equipment response characteristic, in accordance with MOD-026-2 Attachment 1. [~~13~~]*[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M7. Each Generator Owner or Transmission Owner must provide dated evidence such as an updated model or a ~~mutually agreed upon~~ plan ~~with its Transmission Planner~~ to verify the model including transmittal date within 180 calendar days of making changes to in-service equipment (e.g., email message, postal receipt, upload via web portal, etc.) in accordance with Requirement R7.

R8. Each Transmission Planner shall review ~~the verified model and accompanying information, an updated verified model provided~~ materials submitted under Requirement ~~R7, or a written response provided under Requirement R9, provided by a Generator Owner or Transmission Owner~~R2-R7 or R9, and provide ~~a~~ written response to the submitter within ~~90~~ 120 calendar days from receiving ~~the verified model information~~each submission. The written response shall include one of the following: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

- Notification of acceptance: the model and accompanying information meet the acceptance criteria established in Requirement R1, or
- Notification of denial: the model and accompanying information does not meet acceptance criteria established in Requirement R1, or information submitted is incomplete. The notification of denial shall include an explanation and supporting evidence.

M8. Each Transmission Planner must provide dated evidence such as review date of submitted model and accompanying information, review disposition (notification of acceptance or denial), and dated response to the submitter (e.g., email message, postal receipt, etc.) within 90 calendar days of receipt in accordance with Requirement R8.

R9. Each Generator Owner or Transmission Owner receiving a notification of denial under Requirement R8 or a request from its Transmission Planner for a model review due to identified model or accompanying information deficiencies shall provide a written response to its Transmission Planner within 90 calendar days of receiving a notification or request, in accordance with the periodicity in MOD-026-2 Attachment

[~~12~~15] If an updated verification is performed, the 10 year period as outlined in MOD-026 Attachment 1 is reset.

[~~13~~] ~~This includes a hardware, software, firmware, control mode, or setting change to in-service equipment that alters the equipment response characteristics.~~

1. The written response shall contain one of the following: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

- An updated verified model and accompanying information in accordance with Requirements R2–R6,
- A ~~mutually agreed upon~~ plan ~~with its Transmission Planner~~ to verify the model in accordance with Requirements R2–R6, or
- Technical justification and supporting evidence for maintaining the current model.

M9. Each Generator Owner or Transmission Owner must provide dated evidence such as a response (e.g., email message, postal receipt, etc.) containing the information identified in Requirement R9 within 90 calendar days following receipt of notification of denial or request for model review.

C. Compliance

1. **Compliance Monitoring Process**

   1.1. **Compliance Enforcement Authority:** "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

   1.2. **Evidence Retention:** The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

   The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

   - Each Transmission Planner and Planning ~~Authority~~ Coordinator shall keep data or evidence of Requirement R1 since the most current revision date for each of the model processes and requirements.
   - Each Generator Owner and Transmission Owner shall keep data or evidence of Requirement R2 and R3 since the transmission date of the most current verified model(s) provided to the Transmission Planner.
   - Each Generator Owner and Transmission Owner shall keep data or evidence of Requirement R4 and R5 since the transmission date of the most current verified model(s) provided to the Transmission Planner.
   - Each Generator Owner and Transmission Owner shall keep data or evidence of Requirement R6 since the transmission date of the most current verified model(s) provided to the Transmission Planner.
   - Each Generator Owner and Transmission Owner shall keep data or evidence of Requirement R7 since the transmission date of the most current verified model(s) provided to the Transmission Planner.
   - Each Transmission Planner shall keep data or evidence of Requirement R8 for a rolling 36 calendar months.
   - Each Generator Owner shall keep data or evidence of Requirement R9 for a rolling 36 calendar months.

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

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Transmission Planner's dynamic model verification requirements and processes failed to include one of the items in Requirement 1, Parts 1.1 through 1.6.	The Transmission Planner's dynamic model verification requirements and processes failed include two of the items in Requirement 1, Parts 1.1 through 1.6.	The Transmission Planner's dynamic model verification requirements and processes failed to include three of the items in Requirement 1, Parts 1.1 through 1.6.	The Transmission Planner's dynamic model verification requirements and processes failed to include four or more of the items in Requirement 1, Parts 1.1 through 1.6. OR The Transmission Planner and Planning ~~Authority~~ Coordinator failed to jointly develop dynamic model verification requirements and processes. OR The Transmission Planner failed to make available dynamic model verification requirements and processes to the Generator Owner and Transmission Owner.
R2.	The applicable entity provided a verified model(s), with associated parameters, and accompanying information to its Transmission Planner after the date required, but within	The applicable entity provided a verified model(s), with associated parameters, and accompanying information to its Transmission Planner between 91 and 180 calendar days after the date required.	The applicable entity provided a verified model(s), with associated parameters, and accompanying information to its Transmission Planner between 181 and 270 calendar days after the date required.	The applicable entity provided a verified model(s), with associated parameters, and accompanying information to its Transmission Planner more than 270 calendar days after the date required.

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
	90 calendar days after the date required. OR The applicable entity provided a verified model(s) that failed to include one of the items in Requirement R2, Parts 2.1 through 2.4.	OR The applicable entity provided a verified model(s) that failed to include two of the items in Requirement R2, Parts 2.1 through 2.4.	OR The applicable entity provided a verified model(s) that failed to include three of the items in Requirement R2, Parts 2.1 through 2.4.	OR The applicable entity provided a verified model(s) that failed to include four of the items in Requirement R2, Parts 2.1 through 2.4. OR The applicable entity failed to provide a verified model.
R3.	The applicable entity provided a verified model(s)-, with associated parameters, and accompanying information to its Transmission Planner after the date required but within 90 calendar days after the date required. OR The applicable entity provided a verified model(s) that failed to include one of the items in Requirement R3, Parts 3.1 through 3.4.	The applicable entity provided a verified model(s)-, with associated parameters, and accompanying information to its Transmission Planner between 91 and 180 calendar days after the date required. OR The applicable entity provided a verified model(s) that failed to include two of the items in R3, Parts 3.1 through 3.4.	The applicable entity provided a verified model(s)-, with associated parameters, and accompanying information to its Transmission Planner between 181 and 270 calendar days after the date required. OR The applicable entity provided a verified model(s) that failed to include three of the items in Requirement R3, Parts 3.1 through 3.4.	The applicable entity provided a verified model(s)-, with associated parameters, and accompanying information to its Transmission Planner more than 270 calendar days after the date required. OR The applicable entity provided a verified model(s) that failed to include four of the items in Requirement R3, Parts 3.1 through 3.4. OR The applicable entity failed to provide a verified model.
R4.	The applicable entity provided a verified model(s)-, with	The applicable entity provided a verified model(s)-, with	The applicable entity provided a verified model(s)-, with	The applicable entity provided a verified model(s)-, with

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	associated parameters, and accompanying information to its Transmission Planner after the date required but within 90 calendar days after the date required. OR The applicable entity provided a verified model(s) that failed to include one of the items in Requirement R4, Parts 4.1 through 4.4.	associated parameters, and accompanying information to its Transmission Planner between 91 and 180 calendar days after the date required. OR The applicable entity provided a verified model(s) that failed to include two of the items in Requirement R4, Parts 4.1 through 4.4.	associated parameters, and accompanying information to its Transmission Planner between 181 and 270 calendar days after the date required. OR The applicable entity provided a verified model(s) that failed to include three of the items in Requirement R4, Parts 4.1 through 4.4.	associated parameters, and accompanying information to its Transmission Planner more than 270 calendar days after the date required. OR The applicable entity provided a verified model(s) that failed to include four of the items in Requirement R4, Parts 4.1 through 4.4. OR The applicable entity failed to provide a verified model.
R5.	The applicable entity provided a verified model(s)-, with associated parameters, and accompanying information to its Transmission Planner after the date required but within 90 calendar days after the date required. OR The applicable entity provided a verified model(s) that failed to include one of the items in Requirement R5, Parts 5.1 through 5.4.	The applicable entity provided a verified model(s)-, with associated parameters, and accompanying information to its Transmission Planner between 91 and 180 calendar days after the date required. OR The applicable entity provided a verified model(s) that failed to include two of the items in Requirement R5, Parts 5.1 through 5.4.	The applicable entity provided a verified model(s)-, with associated parameters, and accompanying information to its Transmission Planner between 181 and 270 calendar days after the date required. OR The applicable entity provided a verified model(s) that failed to include three of the items in Requirement R5, Parts 5.1 through 5.4.	The applicable entity provided a verified model(s)-, with associated parameters, and accompanying information to its Transmission Planner more than 270 calendar days after the date required. OR The applicable entity provided a verified model(s) that failed to include four of the items in Requirement R5, Parts 5.1 through 5.4.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				OR The applicable entity failed to provide a verified model.
R6.	The applicable entity provided a verified model(s), with associated parameters, and accompanying information to its Transmission Planner after the date required but within 90 calendar days after the date required. OR The applicable entity provided a verified model(s) that failed to include one of the items in Requirement R6, Parts 6.1 through 6.5.	The applicable entity provided a verified model(s), with associated parameters, and accompanying information to its Transmission Planner between 91 and 180 calendar days after the date required. OR The applicable entity provided a verified model(s) that failed to include two of the items in Requirement R6, Parts 6.1 through 6.5.	The applicable entity provided a verified model(s), with associated parameters, and accompanying information to its Transmission Planner between 181 and 270 calendar days after the date required. OR The applicable entity provided a verified model(s) that failed to include three of the items in Requirement R6, Parts 6.1 through 6.5.	The applicable entity provided a verified model(s), with associated parameters, and accompanying information to its Transmission Planner more than 270 calendar days after the date required. OR The applicable entity provided a verified model(s) that failed to include four or more of the items in Requirement R6, Parts 6.1 through 6.5. OR The applicable entity failed to provide a verified model.
R7.	The applicable entity provided an updated verified model(s) or a ~~mutually agreed upon~~ plan to verify the model(s) in accordance with one or more of Requirements R2, R3, R4, R5, or R6 to its Transmission Planner between 181 and 210 calendar days from making a	The applicable entity provided an updated verified model(s) or a ~~mutually agreed upon~~ plan to verify the model(s) in accordance with one or more of Requirements R2, R3, R4, R5, or R6 to its Transmission Planner between 211 and 240 calendar days of making a	The applicable entity provided an updated verified model(s) or a ~~mutually agreed upon~~ plan to verify the model(s) in accordance with one or more of Requirements R2, R3, R4, R5, or R6 to its Transmission Planner between 241 and 270 calendar days of making a	The applicable entity failed to provide an updated verified model(s) or a ~~mutually agreed upon~~ plan to verify the model(s) in accordance with one or more of Requirements R2, R3, R4, R5, or R6 to its Transmission Planner within 270 calendar days of making a

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	change to in-service equipment that altered the equipment response.	change to in-service equipment that altered the equipment response.	change to in-service equipment that altered the equipment response.	change to in-service equipment that altered the equipment response.
R8.	The Transmission Planner reviewed materials submitted under Requirement R2-R7 or R9, but provided ~~a~~ written response to the submitter, between ~~91 to 120~~ 121 to 150 calendar days after receiving ~~the verified model information~~each submission.	The Transmission Planner reviewed materials submitted under Requirement R2-R7 or R9, but provided ~~a~~ written response to the submitter, between ~~121 to 150~~ 151 to 180 calendar days after receiving ~~the verified model information~~each submission.	The Transmission Planner reviewed materials submitted under Requirement R2-R7 or R9, but provided ~~a~~ written response to the submitter, between ~~151 to 180~~ 181 to 210 calendar days after receiving ~~the verified model information~~each submission.	The Transmission Planner ~~failed to provide a~~ reviewed materials submitted under Requirement R2-R7 or R9, but provided written response to the submitter~~, within 180~~ greater than 210 calendar days after receiving ~~the verified model information~~each submission. OR The Transmission Planner reviewed materials submitted under Requirement R2-R7 or R9, and provided ~~a~~ written response with notification of denial, indicating that the model was unacceptable, but did not include an explanation and supporting evidence. OR The Transmission Planner failed to review materials submitted under Requirement R2-R7 or R9, and failed to provide written response to

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				the submitter for each submission.
R9.	The applicable entity provided a written response to the Transmission Planner between 91 to 120 calendar days after receiving a notification of denial or request to perform model review.	The applicable entity provided a written response to the Transmission Planner between 121 to 150 calendar days after receiving a notification of denial or request to perform model review.	The applicable entity provided a written response to the Transmission Planner between 151 to 180 calendar days after receiving a notification of denial or request to perform model review.	The applicable entity failed to provide a written response to the Transmission Planner within 180 calendar days after receiving a notification of denial or request to perform model review. OR The applicable entity's written response failed to contain one of three optional responses described in Requirement R9.

D. Regional Variances

None.

E. Associated Documents

~~Link to for~~ Project 2020-06 Verification of Models for BES Connected Facilities Implementation Plan~~.~~

Project 2020-06 MOD-026-2 Technical Rationale

Project 2020-06 Mapping Document

Version History

Version	Date	Action	Change Tracking
1	February 7, 2013	Adopted by NERC Board of Trustees	New
1	March 20, 2014	FERC Order issued approving MOD-026-1. (Order becomes effective for R1, R3, R4, R5, and R6 on 7/1/14. R2 becomes effective on 7/1/18.)	
1	May 7, 2014	NERC Board of Trustees adopted revisions to VSLs in Requirement R6.	Revisions
1	November 26, 2014	FERC issued a letter order approved revisions to VSLs in Requirement R6.	
2	TBD	Adopted by NERC Board of Trustees	

MOD-026-2 Attachment 1 Model Verification Periodicity		
Row Number	**Verification Condition**	**Required Action**
1	Establishing the initial verification date for an applicable ~~unit~~Facility. (Applies to Requirements R2, R3, R4, R5, and R6)	Transmit the verified model and accompanying information to the Transmission Planner in accordance with the Implementation Plan. ~~Row 7 (equivalent unit verification condition) applies when calculating generation fleet compliance during the implementation period.~~
2	Initial verification for a newly commissioned Facility. (Applies to Requirements R2, R3, R4, R5, and R6)	Transmit the verified model and accompanying information to the Transmission Planner within 365 calendar days after the commissioning date.
3	Subsequent verification for an applicable ~~unit~~Facility. (Applies to Requirements R2, R3, R4, R5, and R6)	Transmit the verified model and accompanying information to the Transmission Planner on or before the 10-year anniversary of the most recent transmittal date.
4	Applicable ~~unit~~ Facility with installed and operating recording equipment does not experience a frequency excursion as applicable per Note 1 by the date otherwise required to meet the dates per Rows 1, 2, 3, 5, or 6. (Applies to Requirements R3 and R5)	Requirement R3 or R5 is met with a written statement transmitted to the Transmission Planner. Transmit the verified model and accompanying information to the Transmission Planner on or before 365 calendar days after a frequency excursion per Note 1 occurs and the recording equipment captures the applicable ~~unit's~~ Facility's real power response as expected.

MOD-026-2 Attachment 1 Model Verification Periodicity		
Row Number	**Verification Condition**	**Required Action**
5	For an existing applicable ~~unit~~ Facility with a change to in-service equipment as described under Requirement ~~R8~~R7. (Applies to Requirement ~~R8~~R7)	Transmit the verified model and accompanying information or a ~~mutually-agreed-upon~~ plan to verify the model to the Transmission Planner within 180 calendar days after making the change to in-service equipment. If ~~mutually-agreed-upon~~ a plan to verify the model is provided to the Transmission Planner, then Row 6 also applies.
6	The Generator Owner or Transmission Owner has provided a ~~mutually agreed upon~~ plan ~~with its Transmission Planner~~ to verify the model. (Applies to Requirements R7 and R9)	Transmit the updated verified model and accompanying information to the Transmission Planner within ~~180~~ 365 calendar days after the ~~verification date specified in the mutually agreed upon plan~~submittal of the plan to verify the model.

MOD-026-2 Attachment 1 Model Verification Periodicity		
Row Number	**Verification Condition**	**Required Action**
7	Existing ~~applicable~~ generating unit or synchronous condenser that is equivalent to another unit(s) at the same physical location. AND Each ~~applicable~~ unit has the same MVA nameplate rating. AND The nameplate rating is ≤ 350 MVA. AND Each ~~applicable~~ unit has the same components and settings. AND The model for one of these equivalent ~~applicable~~ units has been verified. (Applies to Requirements R2, R3, R4, R5, and R6)	Document circumstance with a written statement and include with the verified model, documentation~~-~~, and data provided to the Transmission Planner for the verified equivalent unit. Verify the model(s) of a different equivalent unit during each 10-year verification period. ~~Applies to Row 1 when calculating generation fleet compliance during the implementation period.~~
8	New or existing applicable unit or Facility does not include an active closed loop voltage or reactive power control function. (Requirement R2 or R4 exemption)	Requirement R2 or R4 is met with a written statement to that effect transmitted to the Transmission Planner.

MOD-026-2 Attachment 1 Model Verification Periodicity		
Row Number	**Verification Condition**	**Required Action**
9	Applicable ~~unit~~ Facility is not responsive to~~both over- and under-~~ frequency excursion events during normal operation. (The applicable Facility does not operate in a frequency control mode, except during normal start up and shut down, that would result in a prime mover/governor and load control or active power/frequency control mode response.) OR New or existing applicable ~~unit~~ Facility does not have an installed frequency control system or has a disabled frequency control system. (Requirement R3 or R5 exemption) If the applicable Facility is operating in a frequency control mode that is responsive to a frequency excursion event in only one direction (over- or under-frequency), then R3 and R5 are still applicable.	Requirement R3 or R5 is met with a written statement to that effect transmitted to the Transmission Planner. Perform verification per the periodicity specified in Row 2 for a "Newly commissioned Facility" (or new equipment) only if responsive control mode operation for connected operations is established.

MOD-026-2 Attachment 1 Model Verification Periodicity		
Row Number	**Verification Condition**	**Required Action**
10	Existing applicable ~~unit~~ Facility has a current average net capacity factor over the most recent three calendar years, beginning on January 1 and ending on December 31, of 5% or less. (Requirement R2, R3, R4, R5, or R6 periodicity exemption of Row 1 or Row 3; does not exempt obligation under Requirement R7 or R9.)	Requirement R2, R3, R4, R5, or R6 are met with a written statement to that effect transmitted to the Transmission Planner annually. If the current average net capacity factor over the most recent three calendar years exceeds 5%, then within 365 calendar days model verification must be performed to meet the required action of Row 1 or Row 3. For the definition of net capacity factor, refer to Appendix F of the GADS Data Reporting Instructions on the NERC website.
11	Commissioning date of the applicable Facility is before January 1, ~~2015~~2020; OR OEM is no longer ~~in~~ doing business in North America; OR OEM no longer supports model(s) for in-service equipment at the Facility. (Requirement R6 exemption)	Requirement R6 is met with a written statement to that effect transmitted to the Transmission Planner. If the OEM that commissioned the Facility was acquired, merged, or operating under a different name, the new company would be considered the OEM.

MOD-026-2 Attachment 1 Model Verification Periodicity		
Row Number	**Verification Condition**	**Required Action**

NOTE 1:

Unit model verification frequency excursion criteria:

- ≥ 0.05 hertz deviation (nadir point) from scheduled frequency for the Eastern Interconnection with the applicable ~~unit~~ Facility operating in a frequency responsive mode
- ≥ 0.10 hertz deviation (nadir point) from scheduled frequency for the ERCOT and Western Interconnections with the applicable ~~unit~~ Facility operating in a frequency responsive mode
- ≥ 0.15 hertz deviation (nadir point) from scheduled frequency for the Quebec Interconnection with the applicable ~~unit~~ Facility operating in a frequency responsive mode

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

This is the first draft of the proposed standard for a formal 45-day comment period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 20, 2021
SAR posted for comment	March 4 – April 2, 2021

Anticipated Actions	Date
45-day formal or informal comment period with ballot	September – November 2022
45-day formal or informal comment period with additional ballot	February – April 2023
10-day final ballot	May 2023
Board adoption	August 2023

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:** Verification ~~and Data Reporting of Generator~~ of Real and Reactive Power Capability ~~and Synchronous Condenser Reactive Power Capability~~for BES Facilities

2. **Number:** ~~MOD-025-2~~MOD-025-3

3. **Purpose:** To ensure that accurate information on ~~generator gross and net~~ Bulk Electric System (BES) Facility Real and ~~Reactive Power capability and synchronous condenser~~ Reactive Power capability is available for planning models used to assess ~~Bulk Electric System (~~BES~~)~~ reliability.

4. **Applicability:**

   4.1. Functional ~~entities~~Entities:

   4.1.1 Generator Owner

   4.1.2 Transmission Owner ~~that owns synchronous condenser(s)~~

   4.1.3 Transmission Planner

   4.2. Facilities: For the purpose of this standard, the term, "applicable Facility" or "Facility" shall mean any one of the following:

   4.2.1 Individual generating ~~unit greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System.~~resource identified through Inclusion I2 of the BES definition.

   ~~Synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric **4.2.2**System.~~

   4.2.2 ~~**4.2.3**~~Generating plant/~~Facility greater than 75 MVA (gross aggregate nameplate rating) directly connected to the Bulk Electric System.~~Facility identified through Inclusion I2 of the BES definition.

   4.2.3 Generating plant/Facility of dispersed power producing resources identified through Inclusion I4 of the BES definition.

   4.2.4 Dynamic reactive devices identified through Inclusion I5 of the BES definition with a gross (individual or aggregate) nameplate rating greater than 20 MVA including, but not limited to:

   4.2.4.1 Synchronous condenser; and

   4.2.4.2 Flexible alternating current transmission system (FACTS) devices.

   4.2.5 HVDC terminal equipment including:

   4.2.5.1 Voltage source converter (VSC).

5. **Effective Date:** see Project 2021-01 Modifications to MOD-025 and PRC-019 Implementation Plan.

~~**5.1.** In those jurisdictions where regulatory approval is required[1]:~~

~~**5.1.1** By the first day of the first calendar quarter, two calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable Facilities.~~

~~**5.1.2** By the first day of the first calendar quarter, three calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable Facilities.~~

~~**5.1.3** By the first day of the first calendar quarter, four calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable Facilities.~~

~~**5.1.4** By the first day of the first calendar quarter, five calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable Facilities.~~

~~**5.2.** In those jurisdictions where regulatory approval is not required[2]:~~

~~**5.2.1** By the first day of the first calendar quarter, two calendar years following Board of Trustees approval, each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable Facilities.~~

~~**5.2.2** By the first day of the first calendar quarter, three calendar years following Board of Trustees approval, each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable Facilities.~~

~~**5.2.3** By the first day of the first calendar quarter, four calendar years following Board of Trustees approval, each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable Facilities.~~

~~[1] Wind Farm Verification - If an entity has two wind sites, and verification of one site is complete, the entity is 50% complete regardless of the number of turbines at each site. A wind site is a group of wind turbines connected at a common point of interconnection or utilizing a common aggregate control system.~~

~~[2] Wind farm verification - If an entity has two wind sites, and verification of one site is complete, the entity is 50% complete regardless of the number of turbines at each site. A wind site is a group of wind turbines connected at a common point of interconnection or utilizing a common aggregate control system.~~

~~**5.2.4** By the first day of the first calendar quarter, five calendar years following Board of Trustees approval, each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable Facilities.~~

B. ~~Note: The verification percentage above is based on the number of applicable units owned.~~Requirements and Measures

R1. Each Generator Owner shall ~~provide~~ verify the Real Power and Reactive Power capability of its applicable Facilities and inform its Transmission Planner ~~with verification of the Real Power capability of its applicable Facilities~~ as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. Verify the Real Power capability~~.~~, if applicable, of its ~~generating units~~ applicable Facilities in accordance with Attachment 1.

1.2. ~~Submit a completed Attachment 2~~ Verify the Reactive Power capability ~~(or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test; or (ii) the date the data is selected for verification using historical operational data.~~

~~**R2.** Each Generator Owner shall provide its Transmission Planner with verification of the Reactive Power capability of its applicable Facilities as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*~~

~~**2.1.** Verify,~~ of its applicable Facilities in accordance with Attachment 1~~, (i) the Reactive Power capability of its generating units and (ii) the Reactive Power capability of its synchronous condenser units.~~.

1.3. Submit the following information, in accordance with Attachment 2, to the Transmission Planner within 30 calendar days after the verification date:

1.3.1. One-line diagram representing the Facility;

1.3.2. Composite capability curve and associated PQ data table; and

1.3.3. Documentation showing the engineering basis, verification methodology and/or applicable data for the verification method.

~~**2.2.** Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test; or (ii) the date the data is selected for verification using historical operational data.~~

~~**R3.** Each Transmission Owner shall provide its Transmission Planner with verification of the Reactive Power capability of its applicable Facilities as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*~~

~~**3.1.** Verify, in accordance with Attachment 1, the Reactive Power capability of its synchronous condenser units.~~

~~**3.2.** Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test; or (ii) the date the data is selected for verification using historical operational data.~~

~~B. Measures~~

M1. ~~Each Generator Owner will~~ Each Generator Owner shall have evidence that it ~~performed the verification, such as a completed Attachment 2 or the Generator Owner form with the same information or dated information collected and used to complete attachments, and will~~ verified Real Power and Reactive Power capability of each Facility, such as completed attachments or summary report(s); and have evidence that it submitted the information within ~~90~~ 30 calendar days after the verification date to its Transmission Planner~~; such as dated electronic mail messages or mail receipts~~ in accordance with Requirement R1.

R2. Each Transmission Owner shall verify the Real Power and Reactive Power capability of its applicable Facilities and inform its Transmission Planner as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. Verify the Real Power capability, if applicable, of its applicable Facilities in accordance with Attachment 1.

2.2. Verify the Reactive Power capability of its applicable Facilities, in accordance with Attachment 1.

2.3. Submit the following information per Attachment 2 to the Transmission Planner within 30 calendar days after the verification date:

2.3.1. One-line diagram representing the Facility;

2.3.2. Composite capability curve and associated PQ data table; and

2.3.3. Documentation showing the engineering basis, verification methodology and/or applicable data for the verification method.

M2. ~~Each Generator Owner will have evidence that it performed the verification, such as a completed Attachment 2 or the Generator Owner form with the same information, or dated information collected and used to complete attachments and will~~ Each Transmission Owner shall have evidence that it verified Real Power and Reactive Power capability of each Facility, such as completed attachments or summary report(s); and have evidence that it submitted the information within ~~90~~ 30 calendar days after the verification date to its Transmission Planner~~; such as dated electronic mail messages or mail receipts~~ in accordance with Requirement R2.

~~**M3.** Each Transmission Owner will have evidence that it performed the verification, such as a completed Attachment 2 or the Transmission Owner form with equivalent information or dated information collected and used to complete attachments, and will have evidence that it submitted the information within 90 days to its Transmission Planner; such as dated electronic mail messages or mail receipts in accordance with Requirement R3.~~

R3. Each Transmission Planner shall review the information submitted by each Generator Owner or Transmission Owner in accordance with Requirement R1, R2, or R4 and provide a written response within 90 calendar days containing one of the following: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

- Notification that the Transmission Planner has not identified any technical concerns with the Real and Reactive Power capability information submitted by the Generator Owner or Transmission Owner; or
- Notification that the Transmission Planner has identified a technical concern, including the basis for the technical concern.

M3. Each Transmission Planner shall have evidence, such as a summary of items reviewed and dated correspondence of the notification, that it reviewed the information submitted and provided notification to the Generator Owner or Transmission Owner within 90 calendar days in accordance with Requirement R3.

R4. Each Generator Owner or Transmission Owner receiving a notification of a technical concern under Requirement R3 shall provide a written response to its Transmission Planner within 90 calendar days containing one of the following: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

- Updated capability information in accordance with Requirements R1 or R2;
- A mutually agreed upon plan with its Transmission Planner to update the capability information in accordance with Requirements R1 or R2; or
- Technical justification and supporting evidence for maintaining the existing capability information in accordance with Requirements R1 or R2.

M4. Each Generator Owner or Transmission Owner shall have evidence that it responded to the Transmission Planner within 90 calendar days in accordance with Requirement R4.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

~~The Regional Entity shall serve as the Compliance enforcement authority unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional entity approved by FERC or other applicable governmental authority shall serve as the CEA.~~

~~**1.2. Evidence Retention**~~

1.0. Evidence Retention: The following evidence retention ~~periods~~ period(s) identify ~~a~~ 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 ~~compliance~~ audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

~~The Generator Owner and Transmission Owner shall each keep the~~ The applicable entity shall keep data or evidence to show compliance as identified below, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation~~:~~.

- Each Generator Owner shall keep data or evidence of Requirement R1 since the most current verification for each applicable BES Facility.
- Each Transmission Owner shall keep data or evidence of Requirement R2 since the most current verification for each applicable BES Facility.
- Each Transmission Planner shall keep data or evidence of Requirement R3 for a rolling 12 month period.

~~Generator Owner or Transmission Owner is found noncompliant, it shall keep information related to the noncompliance until mitigation is complete or for the time specified above, whichever is longer.The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.~~

~~**1.1. Compliance Monitoring and Assessment Processes**~~

~~Compliance Audit~~

~~Self-Certification~~

~~Spot Checking~~

~~Compliance Investigation~~

~~Self-Reporting~~

~~Complaint~~

~~1.2. Additional Compliance Information~~

~~None~~

- ~~The Generator Owner shall retain the latest MOD-025 Attachment 2 and the data behind Attachment 2 or Generator Owner form with equivalent information and submittal evidence for Requirements R1 and R2, Measures M1 and M2 for the time period since the last compliance audit.~~
- ~~The Transmission Owner shall retain the latest MOD-025 Attachment 2 and the data behind Attachment 2 or Transmission Owner form with equivalent information and submittal evidence for Requirement R3, Measure M3 for the time period since the last compliance audit.~~
- ~~If a~~ Each Generator Owner and Transmission Owner shall keep data or evidence of Requirement R4 for a rolling 12 month period.

1.1. 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.

~~2.~~Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	~~The Generator Owner verified and recorded the Real Power capability of its applicable generating unit, but submitted the data to its Transmission Planner more than 90 calendar days, but within 120 calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.~~ ~~OR~~ ~~The Generator Owner verified the Real Power capability, per Attachment 1 and submitted the data but was missing 1 to less than or equal to 33 percent of the data.~~	~~The Generator Owner verified and recorded the Real Power capability of its applicable generating unit, but submitted the data to its Transmission Planner more than 120 calendar days, but within 150 calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.~~ ~~OR~~ ~~The Generator Owner verified the Real Power capability, per Attachment 1 and submitted the data but was missing more than 33 to 66 percent of the data.~~	~~The Generator Owner verified and recorded the Real Power capability of its applicable generating unit, but submitted the data to its Transmission Planner more than 150 calendar days, but within 180 calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.~~ ~~OR~~ ~~The Generator Owner verified the Real Power capability, per Attachment 1 and submitted the data but was missing from 67 to 99 percent of the data.~~	~~The Generator Owner verified and recorded the Real Power capability of its applicable generating unit, but submitted the data to its Transmission Planner more than 180 calendar days of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.~~ ~~OR~~ ~~The Generator Owner~~ The applicable entity provided all items in Requirement R1, but did so greater than 270 calendar days after the verification date. OR The applicable entity verified the Real and Reactive Power, but failed to include the

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	~~OR~~ ~~The Generator Owner performed the Real Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 66 calendar months but less than or equal to 69 months.~~ ~~OR~~ ~~The Generator Owner performed the Real Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 12 calendar months but less than or equal to 13 calendar months.~~	~~OR~~ ~~The Generator Owner performed the Real Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 69 calendar months but less than or equal to 72 months.~~ ~~OR~~ ~~The Generator Owner performed the Real Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 13 calendar~~	~~OR~~ ~~The Generator Owner performed the Real Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 72 calendar months but less than or equal to 75 months.~~ ~~OR~~ ~~The Generator Owner performed the Real Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 14 calendar~~	information required in Requirement R1, Part 1.3.2. OR The applicable entity verified the Real and Reactive Power capability per Attachment 1 Section 1 Item 3, but did so in more than 138 calendar months. OR The applicable entity verified the Real and Reactive Power capability per Attachment 1 Section 1 Item 2, 4, or 5, but did so in more than 450 calendar days. OR The applicable entity failed to verify the Real and/or Reactive Power capability~~, per Attachment 1 of an applicable generating unit~~. ~~OR~~

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	The applicable entity provided all items in Requirement R1, but did so between 31 and 90 calendar days after the verification date. OR The applicable entity verified the Real and Reactive Power capability per Attachment 1 Section 1 Item 3, but did so between 10 years (120 calendar months) and 126 calendar months. OR The applicable entity verified the Real and Reactive Power capability per Attachment 1 Section 1 Item 2, 4, or 5, but did so between 181 and 270 calendar days.	~~months but less than or equal to 14 calendar months.~~ The applicable entity provided all items in Requirement R1, but did so between 91 and 180 calendar days after the verification date. OR The applicable entity verified the Real and Reactive Power, but failed to include the information required in Requirement R1, Part 1.3.1. OR The applicable entity verified the Real and Reactive Power capability per Attachment 1 Section 1 Item 3, but did so between 127 and 132 calendar months. OR The applicable entity verified the Real and Reactive Power capability per Attachment 1 Section 1 Item 2, 4, or 5, but	~~months but less than or equal to 15 calendar months.~~ The applicable entity provided all items in Requirement R1, but did so between 181 and 270 calendar days after the verification date. OR The applicable entity verified the Real and Reactive Power, but failed to include the information required in Requirement R1, Part 1.3.3. OR The applicable entity verified the Real and Reactive Power capability per Attachment 1 Section 1 Item 3, but did so between 133 and 138 calendar months. OR The applicable entity verified the Real and Reactive Power capability per Attachment 1 Section 1 Item 2, 4, or 5, but	~~The Generator Owner performed the Real Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 75 calendar months.~~ ~~OR~~ ~~The Generator Owner performed the Real Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 15 calendar months.~~

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		did so between 271 and 360 calendar days.	did so between 361 and 450 calendar days.	
~~R2~~R2.	~~The Generator Owner verified and recorded the Reactive Power capability of its applicable generating unit or applicable synchronous condenser, but submitted the data to its Transmission Planner more than 90 calendar days, but within 120 calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.~~ ~~OR~~ ~~The Generator Owner verified the~~ The applicable entity provided all items in Requirement R2, but did so between 31 and 90 calendar days after the verification date. OR The applicable entity verified the Real and Reactive Power capability per Attachment 1	~~The Generator Owner verified and recorded the Reactive Power capability of its applicable generating unit or applicable synchronous condenser, but submitted the data to its Transmission Planner more than 120 calendar days, but within 150 calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.~~ ~~OR~~ ~~The Generator Owner verified the~~ The applicable entity provided all items in Requirement R2, but did so between 91 and 180 calendar days after the verification date. OR The applicable entity verified the Real and Reactive Power, but failed to include the	~~The Generator Owner verified and recorded the Reactive Power capability of its applicable generating unit or applicable synchronous condenser, but submitted the data to its Transmission Planner more than 150 calendar days, but within 180 calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.~~ ~~OR~~ ~~The Generator Owner verified the~~ The applicable entity provided all items in Requirement R2, but did so between 181 and 270 calendar days after the verification date. OR The applicable entity verified the Real and Reactive Power, but failed to include the	~~The Generator Owner verified and recorded the Reactive Power capability of its applicable generating unit or applicable synchronous condenser, but submitted the data to its Transmission Planner more than 180 calendar days of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.~~ ~~OR~~ ~~The Generator Owner failed to verify the~~ The applicable entity provided all items in Requirement R2, but did so greater than 270 calendar days after the verification date. OR The applicable entity verified the Real and Reactive Power, but failed to include the

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Section 1 Item 3, but did between 10 years (120 calendar months) and 126 calendar months. OR The applicable entity verified the Real and Reactive Power capability~~,~~ per Attachment 1 ~~and submitted the data but was missing 1 to up to and including 33 percent of the data.~~Section 1 Item 2, 4, or 5, but did so between 181 and 270 calendar days. ~~OR~~ ~~The Generator Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 66 calendar months but less than or equal to 69 months.~~	information required in Requirement R2, Part 2.3.1. OR The applicable entity verified the Real and Reactive Power capability~~, per Attachment 1 and submitted the data but was missing 34 to 66 percent of the data.~~ per Attachment 1 Section 1 Item 3, but did so between 127 and 132 calendar months. OR The applicable entity verified the Real and Reactive Power capability per Attachment 1 Section 1 Item 2, 4, or 5, but did so between 271 and 360 calendar days. ~~OR~~ ~~The Generator Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new~~	information required in Requirement R2, Part 2.3.3. OR The applicable entity verified the Real and Reactive Power capability~~, per Attachment 1 and submitted the data but was missing 67 to 99 percent of the data.~~ per Attachment 1 Section 1 Item 3, but did so between 133 and 138 calendar months. OR The applicable entity verified the Real and Reactive Power capability per Attachment 1 Section 1 Item 2, 4, or 5, but did so between 361 and 450 calendar days. ~~OR~~ ~~The Generator Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new~~	information required in Requirement R2, Part 2.3.2. OR The applicable entity verified the Real and Reactive Power capability~~,~~ per Attachment 1 ~~of an applicable generating unit or synchronous condenser unit. OR The Generator Owner performed the Reactive Power verification per Attachment 1~~Section 1 Item 3, ~~"Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement)~~ but did so in more than ~~75~~ 138 calendar months. OR ~~The Generator Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in~~

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	~~OR~~ ~~The Generator Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 12 calendar months but less than or equal to 13 calendar months.~~	~~verification" item 1 or item 2 (5 year requirement) but did so in more than 69 calendar months but less than or equal to 72 months.~~ ~~OR~~ ~~The Generator Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 13 calendar months but less than or equal to 14 calendar months.~~	~~verification" item 1 or item 2 (5 year requirement) but did so in more than 72 calendar months but less than or equal to 75 months.~~ ~~OR~~ ~~The Generator Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 14 calendar months but less than or equal to 15 calendar months.~~	~~more than 15 calendar months.~~ The applicable entity verified the Real and Reactive Power capability per Attachment 1 Section 1 Item 2, 4, or 5, but did so in more than 450 calendar days. OR The applicable entity failed to verify the Real and/or Reactive Power capability.
~~R3~~**R3.**	The ~~Transmission Owner verified and recorded the Reactive Power capability of its applicable synchronous condenser, but submitted the data to its~~ Transmission Planner ~~more than 90~~	~~The Transmission Owner verified and recorded the Reactive Power capability of its applicable synchronous condenser, but submitted the data to its Transmission Planner more than 120 calendar days, but within 150~~	~~The Transmission Owner verified and recorded the Reactive Power capability of an applicable synchronous condenser unit, but submitted the data to its Transmission Planner more than 150 calendar days, but within 180~~	~~The Transmission Owner verified and recorded the Reactive Power capability of its applicable synchronous condenser, but submitted the data to its Transmission Planner more than 180 calendar days of the date the~~

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	~~calendar days, but within 120 calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.~~provided a written response to the submitter, but it was provided between 91 to 120 calendar days after receiving the verified model information. ~~OR~~ ~~The Transmission Owner verified the Reactive Power capability, per Attachment 1 and submitted the data but was missing 1 to up to and including 33 percent of the data.~~ ~~OR~~ ~~The Transmission Owner performed the Reactive Power verification per~~	~~calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.~~ ~~OR~~ ~~The Transmission Owner verified the Reactive Power capability, per Attachment 1 and submitted the data but was missing 34 to 66 percent of the data.~~ ~~OR~~ ~~The Transmission Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 69 calendar~~	~~calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.~~ ~~OR~~ ~~The Transmission Owner verified the Reactive Power capability, per Attachment 1 and submitted the data but was missing 67 to 99 percent of the data.~~ ~~OR~~ ~~The Transmission Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 72 calendar~~	~~data is recorded for a staged test or the date the data is selected for verification using historical operational data.~~ ~~OR~~ ~~The Transmission Owner failed to verify the Reactive Power capability, per Attachment 1 of an applicable synchronous condenser unit.~~ ~~OR~~ ~~The Transmission Owner performed the verification per Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 75 calendar months.~~ ~~OR~~

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	~~Attachment 1, "Periodicity for conducting a new verification" item 1 or item 2 (5 year requirement) but did so in more than 66 calendar months but less than or equal to 69 months.~~ ~~OR~~ ~~The Transmission Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 12 calendar months but less than or equal to 13 calendar months.~~	~~months but less than or equal to 72 months.~~ ~~OR~~ ~~The Transmission Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 13 calendar months but less than or equal to 14 calendar months.~~ The Transmission Planner provided a written response to the submitter, but it was provided between 121 to 150 calendar days after receiving the verified model information.	~~months but less than or equal to 75 months.~~ ~~OR~~ ~~The Transmission Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 14 calendar months but less than or equal to 15 calendar months.~~ The Transmission Planner provided a written response to the submitter, but it was provided between 151 to 180 calendar days after receiving the verified model information.	~~The Transmission Owner performed the Reactive Power verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 15calendar months.~~ The Transmission Planner failed to provide a written response to the submitter. OR The Transmission Planner provided a written response to the submitter but it was provided more than 180 calendar days after receiving the verified model information.
R4.	The applicable entity provided a written response to its Transmission Planner, but it was provided between 91 to	The applicable entity provided a written response to its Transmission Planner, but it was provided between 121 to	The applicable entity provided a written response to its Transmission Planner, but it was provided between 151 to	The applicable entity failed to provide a written response to its Transmission Planner.

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
	120 calendar days after receiving a notification of technical concern.	150 calendar days after receiving a notification of technical concern.	180 calendar days after receiving a notification of technical concern.	OR The applicable entity provided a written response to its Transmission Planner, but it was provided greater than 180 calendar days after receiving a notification of technical concern.

D. Regional Variances

None.

E. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	12/1/2005	1. Changed tabs in footer. 2. Removed comma after 2004 in "Development Steps Completed," #1. 3. Changed incorrect use of certain hyphens (-) to "en dash" (–) and "em dash (—)." 4. Added "periods" to items where appropriate. 5. Changed apostrophes to "smart" symbols. 6. Changed "Timeframe" to "Time Frame" in item D, 1.2. 7. Lower cased all instances of "regional" in section D.3. 8. Removed the word "less" after 94% in section 3.4. Level 4.	01/20/06
2	February 7, 2013	Adopted by NERC Board of Trustees	Revised per SAR for Project 2007-09 and combined with MOD-024-1
2	March 20, 2014	FERC Order issued approving MOD-025-2. (Order becomes effective on 7/1/16.)	
3	TBD	Adopted by NERC Board of Trustees	Revised per SAR for Project 2021-01

~~MOD-025~~ MOD-025-3 Attachment 1

~~Verification of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability~~

Section I. Periodicity ~~for conducting a new~~ of verification:

The periodicity ~~for performing~~ to verify the Real and Reactive Power capability ~~verification~~ for each applicable BES Facility is as follows:

1. The applicable entity designates the verification date and notates the verification date in a summary report (refer to Attachment 2). The verification date should represent the date that the engineering review or engineering analysis is complete. The verification date is the basis of the recurring periodicity.
2. Verify each new applicable Facility within 180 calendar days of its commercial operation date.
3. Verify each existing applicable Facility at a periodicity not to exceed ten years from the last verification date.
4. ~~1.For staged verification; verify each applicable Facility at least every five years (with no more than 66 calendar months between verifications), or within 12 calendar months~~ Verify an existing applicable Facility within 180 calendar days of the discovery of a change that affects its Real Power or Reactive Power capability by more than a 10 percent ~~of the last reported verified capability~~ increase or decrease of the nameplate rating and is expected to last more than ~~six months. The first verification for each applicable Facility under this standard must be a staged test.~~180 calendar days.
5. Verify an existing applicable Facility within 180 calendar days of its return to service date, if the Facility has a planned or unplanned outage of 180 calendar days or more which overlaps its scheduled verification date and has not had its capability verified within the past ten years.

~~2. For verification using operational data; verify each applicable Facility at least every five years (with no more than 66 calendar months between verifications), or within 12 calendar months following the discovery that its Real Power or Reactive Power capability has changed by more than 10 percent of the last reported verified capability and is expected to last more than six months. If data for different points is recorded on different days, designate the earliest of those dates as the verification date, and report that date as the verification date on MOD-025, Attachment 2 for periodicity purposes.~~

~~3. For either verification method, verify each new applicable Facility within 12 calendar months of its commercial operation date. Existing units that have been in long term shut down and have not been tested for more than five years shall be verified within 12 calendar months.~~

~~It is intended that Real Power testing be performed at the same time as full load Reactive Power testing, however separate testing is allowed for this standard. For synchronous condensers, perform only the Reactive Power capability verifications as specified below.~~

~~If the Reactive Power capability is verified through test, it is to be scheduled at a time advantageous for the unit being verified to demonstrate its Reactive Power capabilities while the Transmission Operator takes measures to maintain the plant's system bus voltage at the scheduled value or within acceptable tolerance of the scheduled value.~~

Section II. Verification specifications for applicable Facilities:

1. ~~For generating units of 20 MVA or less that are part of a plant greater than 75 MVA in aggregate, record data either on an individual unit basis or as a group. Perform verification individually for every generating unit or synchronous condenser~~ For individual devices or generators greater than 20 MVA (gross nameplate rating) ~~.~~perform verification on an individual basis.

   ~~2.2. Verify Reactive Power capability of all applicable Facilities, other than wind and photovoltaic, for maximum overexcited (lagging) and under-excited (leading) reactive capability for the following conditions:~~

      ~~2.2.1 At the minimum Real Power output at which they are normally expected to operate collect maximum leading and lagging reactive values as soon as a limit is reached.~~

      ~~2.2.2 At maximum Real Power output collect maximum leading reactive values as soon as a limit is reached.~~

      ~~2.2.3 Nuclear Units are not required to perform Reactive Power verification at minimum Real Power output.~~

   ~~2.3. For hydrogen-cooled generators, perform the verification at normal operating hydrogen pressure.~~

   ~~2.4. Calculate the Generator Step-Up (GSU) transformer losses if the verification measurements are taken from the high side of the GSU transformer. GSU transformer real and reactive losses may be estimated, based on the GSU impedance, if necessary.~~

~~3. Record the following data for the verifications specified above:~~

   ~~3.1. The value of the gross Real and Reactive Power generating capabilities at the end of the verification period.~~

   ~~3.2. The voltage schedule provided by the Transmission Operator, if applicable.~~

~~2. Verify with all auxiliary equipment needed for expected normal operation in service for both the Real Power and Reactive Power capability verification. Perform verification with the automatic voltage regulator in service for the Reactive Power capability verification. Operational data from within the two years prior to the verification date is acceptable for the verification of either the Real Power or the Reactive Power capability, as long as a) that operational data meets the criteria in 2.1 through 2.4 below and b) the operational data demonstrates at least 90 percent of a previously staged test that demonstrated at least 50 percent of the Reactive capability shown on the associated~~

~~thermal capability curve (D-curve). If the previously staged test was unduly restricted (so that it did not demonstrate at least 50 percent of the associated thermal capability curve) by unusual generation or equipment limitations (e.g., capacitor or reactor banks out of service), then the next verification will be by another staged test, not operational data:~~

~~2.1. Verify Real Power capability and Reactive Power capability over-excited (lagging) of all applicable Facilities at the applicable Facilities' normal (not emergency) expected maximum Real Power output at the time of the verifications.~~

~~2.1.1 Verify synchronous generating unit's maximum real power and lagging reactive power for a minimum of one hour.~~

2. ~~2.1.2Verify variable generating units, such as wind, solar, and run of river hydro,~~ For individual devices or generators ~~at the maximum Real Power output the variable resource can provide at the time of the verification. Perform verification of Reactive Power capability of wind turbines and photovoltaic inverters with at least 90 percent of the wind turbines or photovoltaic inverters at a site on-line. If verification of wind turbines or photovoltaic inverter Facility cannot be accomplished meeting the 90 percent threshold, document the reasons the threshold was not met and test to the full capability at the time of the test. Reschedule the test of the facility within six months of being able to reach the 90 percent threshold. Maintain, as steady as practical, Real and Reactive Power output during verifications.~~ 20 MVA (gross nameplate rating) or less that are part of an applicable Facility greater than 75 MVA (gross nameplate rating) in aggregate, perform verification on an individual unit basis or in the aggregate, considering applicable modeling expectations of the respective Transmission Planner.

3. Create a simplified key one-line diagram representing the Facility (refer to Attachment 2). The one-line diagram shall designate where the composite capability curve created in Section II, Items 6-8 is represented.

   3.1. ~~3.3.The voltage at the high and low side of the GSU~~ The one-line representing the Facility shall include all auxiliary equipment expected to be in-service for normal operation, including dynamic and static reactive devices and auxiliary load, the GSU, and/or system interconnection transformer(s) ~~at the end of the verification period. If only one of these values is metered, the other may be calculated.~~, unit auxiliary transformer(s), and station services auxiliary transformer(s).

4. If an applicable Facility has no leading or lagging capability, then it should be reported with no leading or lagging capability.

5. The Generator Owner or Transmission Owner shall utilize and document one or more of the following methodologies to verify the Facility capability for all equipment expected to be in-service for normal operation. The engineering review or

engineering analysis shall include underlying assumptions, design criteria, and methods used to create the Facility capability curve under Section II, Items 6-8.

- Perform an engineering review of all Real and Reactive Power Facility capability information including but not limited to in-service equipment design limitations, excitation limiter settings, and operational limitations;
- Utilize staged testing data, in accordance with Section III, obtained from a date within 365 calendar days prior to verification date, and perform engineering analysis as needed per Note 1, that validates the generator capability; or
- Utilize operational data, in accordance with Section III, obtained from a date within 365 calendar days prior to verification date, and perform engineering analysis as needed per Note 1, that validates the generator capability.

6. For an applicable Facility as identified in Section 4.2.1, 4.2.2, or 4.2.4.1, when performing verification on an individual unit basis, create a graphical representation of the steady-state composite capability curve (CCC) for the Real Power and Reactive Power. The steady-state CCC shall include at a minimum the following:

   6.1. The generator steady-state Real Power and Reactive Power capability curve, or the synchronous condenser steady-state Reactive Power capability curve, provided by the equipment manufacturer.

      6.1.1 The curve shall represent generator/synchronous condenser capability at a nominal voltage of 1.0 per unit at the generator/synchronous condenser terminal; and

      6.1.2 The curve shall notate the operating conditions that dictate the power capability, for example H2 pressure, ambient temperature, or other conditions.

   6.2. Excitation limiters, if more restrictive than the equipment manufacturer's capability curve, at nominal voltage 1.0 per unit;

   6.3. Identification of any Real Power or Reactive Power operational limitations[1], if applicable;

   6.4. Identification of the steady-state minimum (P_{min}) and maximum (P_{max}) Real Power output at the generator terminal(s), based on the least restrictive seasonal or operating conditions; and

   6.5. Identification of final PQ curve, which defines the normal operating region.

[1] Such as generator cooling, vibration, de-rated rotor, de-rated GSU transformer, generator bus de-rating, software limitations, or distributed control system (DCS) setpoints (outer-loop control system paths). This excludes fuel availability, such as water levels for hydro, cloud cover for PV, wind speed, or river level for run of river.

7. For an applicable Facility as identified in Section 4.2.2 or Section 4.2.3, when performing verification in aggregate, create a graphical representation of the steady-state composite capability curve (CCC) for the Real Power and Reactive Power. The steady-state CCC shall include at a minimum the following:

    7.1. The steady-state Real and Reactive Power capability curve represented as an aggregate.

        7.1.1 The curve shall represent Facility capability at a steady-state nominal voltage of 1.0 per unit at the common point of connection; and

        7.1.2 The curve shall notate the operating conditions that dictate the power capability, for example H2 pressure, ambient temperature, or other conditions.

    7.2. Aggregate Facility capability includes all auxiliary equipment expected to be in-service for normal operation, including dynamic and static reactive resources and auxiliary loads;

    7.3. Identification of any Real Power or Reactive Power operational limitations, if applicable;

    7.4. For inverter based resources, a description of all power plant controller and inverter control functions during normal operating conditions that dictate the aggregate Facility capability;

    7.5. Identification of the steady-state minimum (P_{min}) and maximum (P_{max}) Real Power output at the common point of connection, based on the least restrictive seasonal or operating conditions; and

    7.6. Identification of final PQ curve, which defines the normal operating region.

8. For an applicable Facility as identified in Section 4.2.4.2 and Section 4.2.5.1, create a graphical representation of the steady-state composite capability curve (CCC) for the Real Power and Reactive Power. The steady-state CCC shall include at a minimum the following:

    8.1. The HVDC steady-state Real Power and Reactive Power capability curve, or the FACTS device steady-state Reactive Power capability, provided by the equipment manufacturer.

        8.1.1 The curve shall represent Facility capability at a steady-state nominal voltage of 1.0 per unit at the common point of connection ; and

        8.1.2 The curve shall notate the operating conditions that dictate the power capability, for example ambient temperature or other conditions.

    8.2. Any limiters, if more restrictive than the equipment manufacturer's capability curve(s), at nominal voltage 1.0 per unit;

8.3. Identification of any Real Power or Reactive Power operational limitations, if applicable;

8.4. A description of all control functions during normal operating conditions and a description of any Facility overload capabilities that dictate the aggregate Facility capability;

8.5. Identification of the steady-state minimum (P_{min}) and maximum (P_{max}) Real Power output at the common point of connection, based on the least restrictive seasonal or operating conditions; and

8.6. Identification of final PQ curve, which defines the normal operating region.

Section III. Staged test and operational data specifications

1. Section III applies when a staged test and/or operational data verification methodology is utilized. If utilizing multiple methodologies to verify the Facility capability, not all data points outlined in Section III, Item 6, 7, 8, or 9 need to be recorded.

~~3.4. The ambient conditions, if applicable, at the end of the verification period that the Generator Owner requires to perform corrections to Real Power for different ambient conditions such as:~~

- ~~Ambient air temperature~~
- ~~Relative humidity~~
- ~~Cooling water temperature~~
- ~~Other data as determined to be applicable by the Generator Owner to perform corrections for ambient conditions.~~

~~3.5. The date and time of the verification period, including start and end time in hours and minutes.~~

~~3.6. The existing GSU and/or system interconnection transformer(s) voltage ratio and tap setting.~~

~~3.7. The GSU transformer losses (real or reactive) if the verification measurements were taken from the high side of the GSU transformer.~~

~~3.8. Whether the test data is a result of a staged test or if it is operational data.~~

~~4. Develop a simplified key one-line diagram (refer to MOD-025, Attachment 2) showing sources of auxiliary Real and Reactive Power and associated system connections for each unit verified. Include GSU and/or system Interconnection and auxiliary transformers. Show Reactive Power flows, with directional arrows.~~

2. ~~4.1.If metering does not exist to measure specific Reactive auxiliary load(s)~~Record any staged test or operational data in Attachment 3 (or a form containing the same information). If metering does not exist to measure specific values listed in

Attachment 3, provide an engineering estimate and associated calculations. ~~Transformer Real and Reactive Power losses will also be estimates or calculations. Only output data are required when using a computer program to calculate losses or loads.~~ Refer to the associated labels depicted in the one-line diagram created in Section II, Item 4. Record any additional data deemed necessary to perform engineering analysis per Note 1.

3. Staged testing or operating conditions should be maintained constant for a sufficient time in order to ensure that the applicable Facility can perform at that level of Real and Reactive Power during steady-state conditions.

4. All auxiliary equipment is expected to be in service for normal operation.

5. The automatic voltage regulating equipment is in automatic voltage regulating mode.

6. For an applicable Facility with Real Power capability, record measurements at the following four points:

   6.1. Maximum lagging Reactive Power at maximum Real Power until a limit is reached;[2]

   6.2. Maximum leading Reactive Power at maximum Real Power until a limit is reached;

   6.3. Maximum lagging Reactive Power at minimum Real Power until a limit is reached;

   6.4. Maximum leading Reactive Power at minimum Real Power until a limit is reached.

7. For an applicable Facility with no Real Power capability, record measurements at the following two points (one over-excited point and one under-excited point):

   7.1. Maximum lagging Reactive Power until a limit is reached;

   7.2. Maximum leading Reactive Power until a limit is reached.

8. For an applicable Facility with equal minimum and maximum Real Power output during normal operation, such as a nuclear unit, record measurements at the two points in Items 8.1 and 8.2 below. The Facility need only perform staged testing or provide operational data for Reactive Power at maximum Real Power output. If applicable, provide the theoretical Reactive Power capability at minimum Real Power output in accordance with Attachment 2.

   8.1. Maximum lagging Reactive Power at normal operating Real Power until a limit is reached;

[2] In addition, consider steady state thermal or mechanical limitations of Facility equipment to determine whether it limits the Reactive Power capability during a staged test.

8.2. Maximum leading Reactive Power at normal operating Real Power until a limit is reached.

9. For variable generating resources, such as wind, solar, or run-of-river hydro, and non-variable generating resources, such as battery energy storage systems, staged testing or operational data should be recorded with at least 90 percent of the inverters/generators at a Facility on-line. If staged testing or operational data capture of a Facility cannot be accomplished while meeting the 90 percent inverter/generator threshold, document the reason(s) the threshold was not met and test to the full available capability at the time of the test. Maintain, as steady as practical, the maximum Real Power output that the resource can provide at the time of the verification. Record measurements at the two points in Items 9.1 and 9.2 below at the maximum Real Power output the variable resource can provide at the time of the staged test or operational data.

9.1. Maximum lagging Reactive Power at normal operating Real Power until a limit is reached;

9.2. Maximum leading Reactive Power at normal operating Real Power until a limit is reached.

~~5. If an adjustment is requested by the Transmission Planner, then develop the relationships between test conditions and generator output so that the amount of Real Power that can be expected to be delivered from a generator can be determined at different conditions, such as peak summer conditions. Adjust MW values tested to the ambient conditions specified by the Transmission Planner upon request and submit them to the Transmission Planner within 90 days of the request or the date the data was recorded/selected whichever is later.~~

~~Note 1: Under some transmission system conditions, the data points obtained by the Mvar verification required by the standard will not duplicate the manufacturer supplied thermal capability curve (D-curve). However, the verification required by the standard, even when conducted under these transmission system conditions, may uncover applicable Facility limitations; such as rotor thermal instability, improper tap settings or voltage ratios, inaccurate AVR operation, etc., which could be further analyzed for resolution. The Mvar limit level(s) achieved during a staged test or from operational data may not be representative of the unit's reactive capability for extreme system conditions. See Note 2.~~

~~Note 2:While not required by the standard, it is desirable to perform engineering analyses~~ Note 1: Under restrictive transmission system conditions, the data points obtained from a staged test or operational data might not duplicate the manufacturer supplied thermal capability curve (D-curve). When the applicable Facility's reactive capability is not fully demonstrated, perform a simulation or engineering analysis to determine expected ~~applicable Facility capabilities~~ capability under less restrictive system voltages ~~than those encountered during the verification~~. Even though this analysis will not verify the complete thermal capability curve (D-curve), it provides a reasonable estimate of applicable Facility capability that the Transmission Planner can use for modeling.

~~Note 3: The Reactive Power verification is intended to define the limits of the unit's Reactive Power capabilities. If a unit has no leading capability, then it should be reported with no leading capability; or the minimum lagging capability at which it can operate.~~

~~Note 4: Synchronous Condensers only need to be tested at two points (one over-excited point and one under-excited point) since they have no Real Power output.~~

~~MOD-025 Attachment 2~~

MOD-025-3 Attachment 2 – BES Facility Capability Report

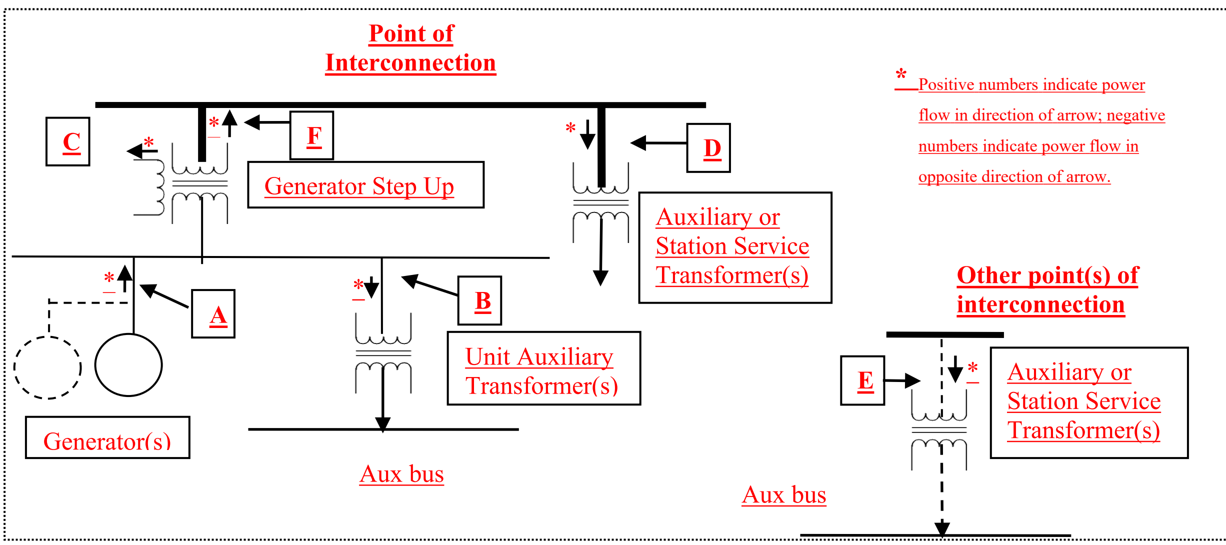
A completed report shall contain the following information at a minimum per Requirement R1 and R2:

- Section I: One-line diagram of the applicable Facility
- Section II: Composite capability curve
- Section III: Associated PQ data table
- Section IV: Documentation showing the engineering basis and verification methodology

If the configuration of the applicable Facility does not lend itself to the use of the one-line diagram, capability curve, and data tables for reporting the required information, changes may be made to this form, provided that all required information (identified in MOD-025-3, Attachment 1) is reported. An example report is provided below.

Company:	**Reported By (name):**	
Plant:	**Unit No.:**	**Date of Verification:**

Section I. Provide simplified one-line diagram of the applicable Facility showing plant auxiliary Load connections.



The composite capability curve provided below is applied at Point (XX) in the one-line diagram shown above.

Section II. Provide composite capability curve as defined in Attachment 1, Section II

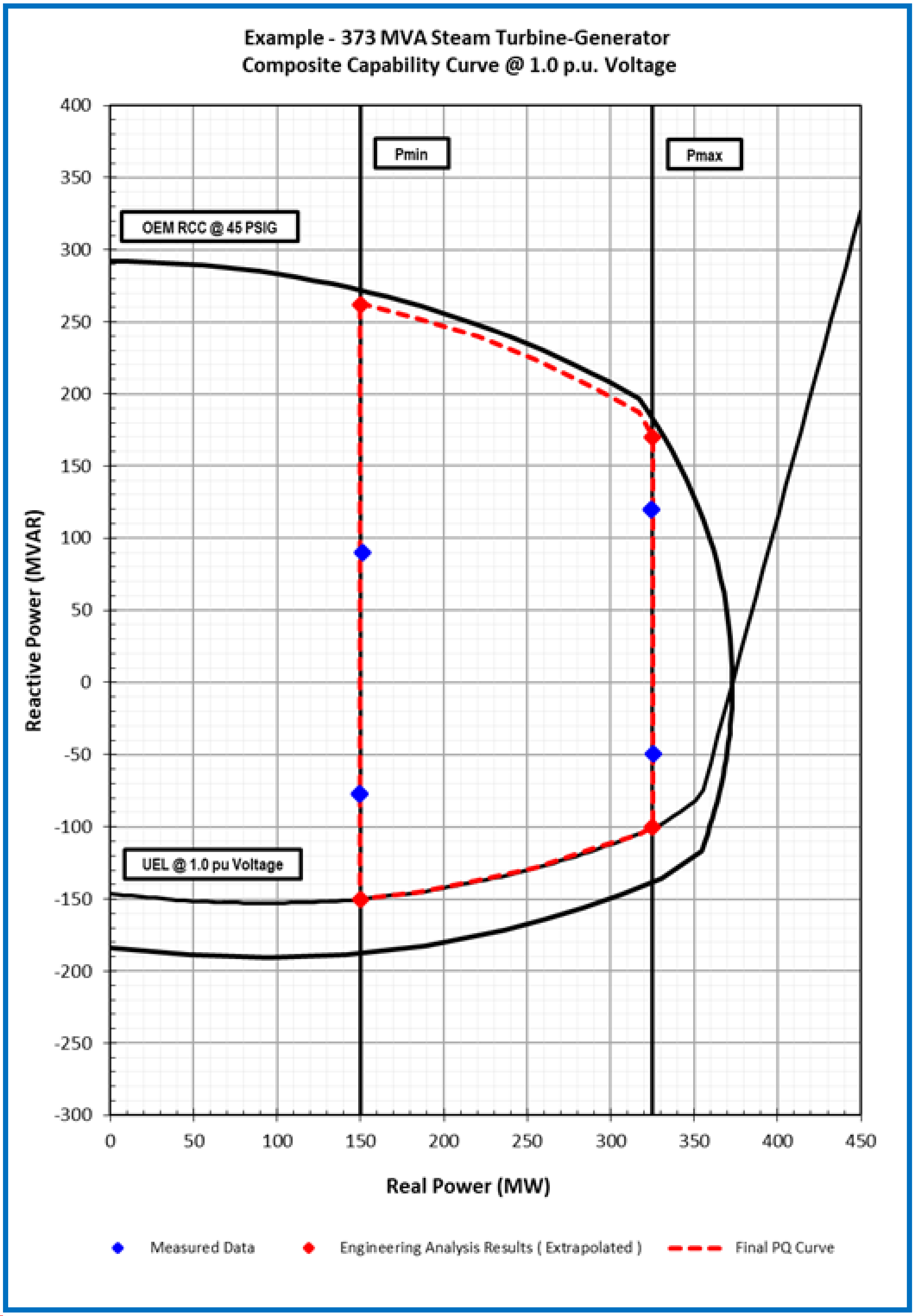


Figure 1: Example Composite Capability Curve for Synchronous Generator

Section III. Provided PQ curve data table associated with Figure 1.X composite capability curve

	P (MW)	Qmin (MVAr)	Qmax (MVAr)	Qmin Limit	Qmax Limit
Pmin	150.0	-150.0	263.0	UEL @ 1.0 Vterm	Ifd Rated
Pmin + 20% of range	185.0	-145.0	252.0	UEL @ 1.0 Vterm	Ifd Rated
Pmin + 40% of range	220.0	-137.0	240.0	UEL @ 1.0 Vterm	Ifd Rated
Pmin + 60% of range	255.0	-128.0	224.0	UEL @ 1.0 Vterm	Ifd Rated
Pmin + 80% of range	290.0	-115.0	204.0	UEL @ 1.0 Vterm	Ifd Rated
Breakpoint	317.1	-105.0	187.0	UEL @ 1.0 Vterm	Ifd Rated
Pmax	325.0	-100.0	170.0	UEL @ 1.0 Vterm	Ifd Rated

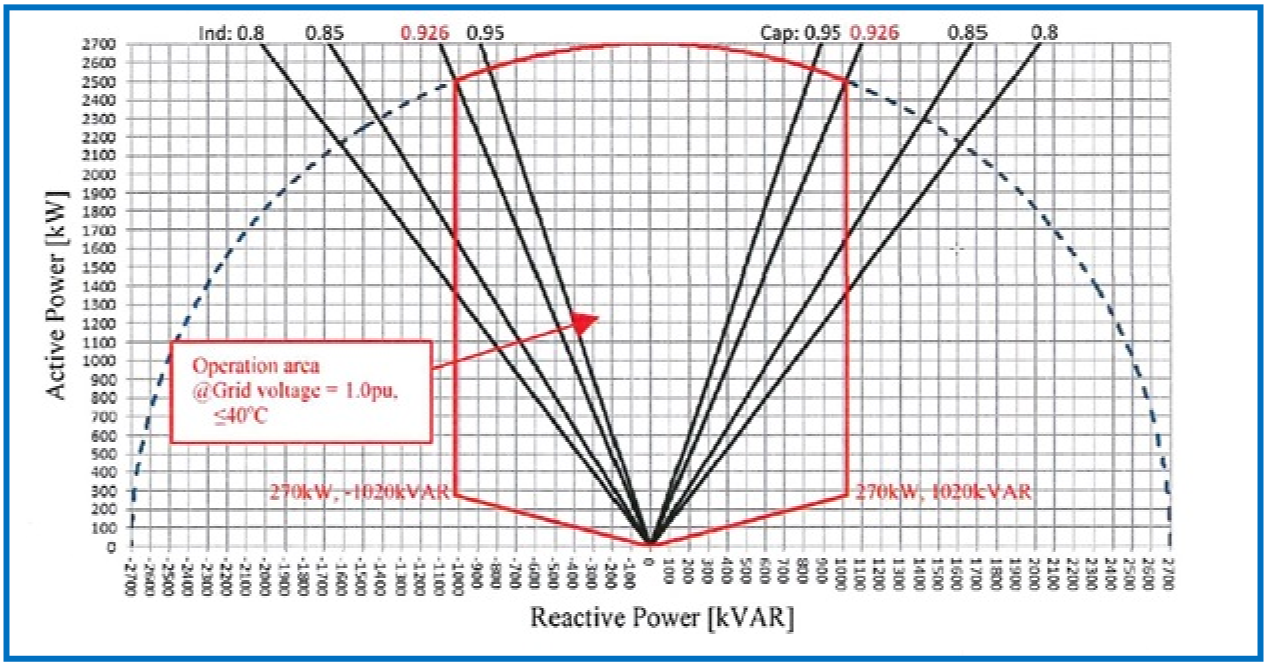


Figure 2: Example Composite Capability Curve for IBR Facility

PQ Curve Data Table (template)

Description	**Pmax** (MW)	**Qmax** (MVAR)	**Qmin** (MVAR)	**Qmax** Limiting Factor	**Qmin** Limiting Factor
P_{min}					
P_{min} + (0.20*Range) Range = (P_{max} - P_{min})					
P_{min} + (0.40*Range)					
P_{min} + (0.60*Range)					
P_{min} + (0.80*Range)					
P_{max}					
Additional data points such as breakpoints are optional.					

1. Limiting factor: UEL/OEL, field current rating, distributed control system (DCS) limit, etc.

Section IV. Supplemental documentation of engineering basis and verification methodology

MOD-025 Attachment 3

~~One-line Diagram, Table,~~ Data Table and Summary ~~for Verification Information Reporting~~of Staged Test or Operational Data

~~Note:~~Reference Attachment 2 one-line diagram measurement points and direction of flow arrows when recording Real and Reactive Power in data table. If the configuration of the applicable Facility does not lend itself to the use of the diagram, tables, or summaries for reporting the required information, changes may be made to this form, provided that all required information ~~(identified in MOD-025, Attachment 1)~~ is reported.

Company: **Reported By (name):**

Plant: **Unit No.:** ~~**Date of Report:**~~

Check all that apply:

☐ Over-excited ~~Full~~ Maximum Load Reactive Power Verification

☐ Under-excited ~~Full~~ Maximum Load Reactive Power Verification

☐ Over-excited Minimum Load Reactive Power Verification

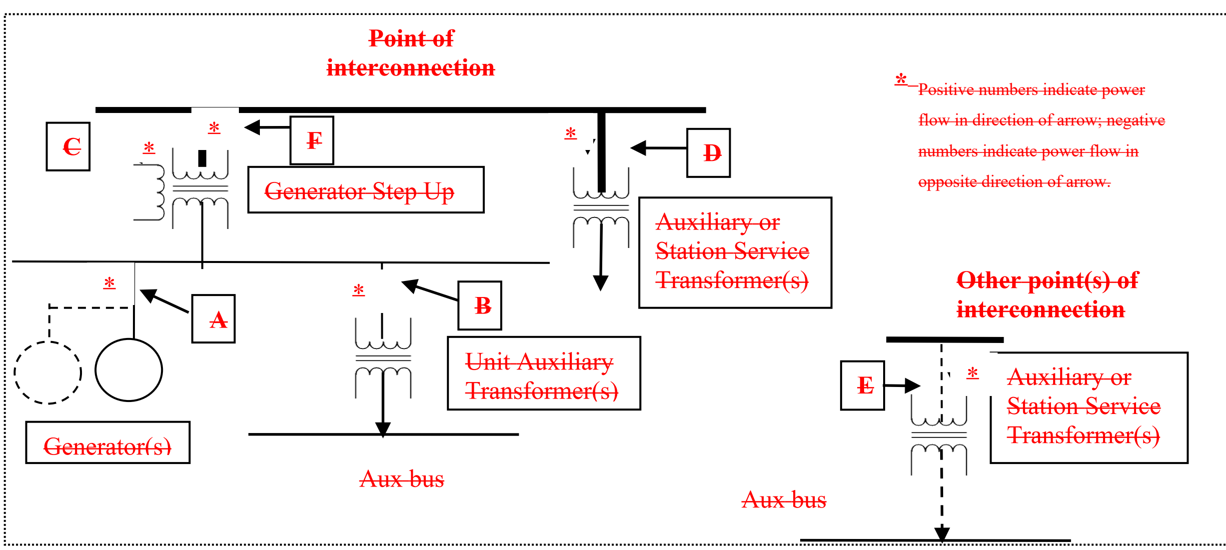
☐ Under-excited Minimum Load Reactive Power Verification

☐ Real Power Verification

☐ Staged Test Data

☐ Operational Data

~~Simplified one-line diagram showing plant auxiliary Load connections and verification data:~~



Data Table for Recording Measurements

Point	Voltage	Real Power	Reactive Power	Comment
A	**kV**	**MW**	**Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B	**kV**	**MW**	**Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any:				
C	**kV**	**MW**	**Mvar**	Sum multiple tertiary Loads, if any.
Identify calculated values, if any:				
D	**kV**	**MW**	**Mvar**	Sum multiple auxiliary and station service transformers.
Identify calculated values, if any:				
E	**kV**	**MW**	**Mvar**	If multiple points of Interconnection, describe these for accurate modeling; report points individually (sum multiple auxiliary transformers).
F	**kV**	**MW**	**Mvar**	Net unit capability
Identify calculated values, if any:				

~~MOD-025 -Attachment 2 (continued)~~

~~Verification Data~~

~~Provide data by unit or Facility, as appropriate~~

~~Data Type~~	~~Data Recorded~~	~~Last Verification (Previous Data; will be blank for the initial verification)~~
~~Gross Reactive Power Capability (*Mvar)~~		
~~Aux Reactive Power (*Mvar)~~		
~~Net Reactive Power Capability (*Mvar) equals Gross Reactive Power Capability (*Mvar) minus Aux Reactive Power connected at the same bus (*Mvar) minus tertiary Reactive Power connected at the same bus(*Mvar)~~		
~~Gross Real Power Capability (*MW)~~		
~~Aux Real Power (*MW)~~		
~~Net Real Power Capability (*MW) equals Gross Real Power Capability (*MW) minus Aux Real Power connected at the same bus (*MW) minus tertiary Real Power connected at the same bus(*MW)~~		

~~* Note: Enter values at the end of the verification period.~~

~~GSU losses (only required if verification measurements are taken on the high side of the GSU - Mvar)~~		

Summary of ~~Verification~~Test / Operational Data

- Date of Staged Test (or oldest Date of Operational Data): ___________
- ~~Date of Verification~~ ___________, ~~Verification~~ Start Time ______, ~~Verification~~ End Time _______, Staged Test or Operational Data _______
  - ~~Scheduled Voltage~~ _______________
- Transformer Voltage Ratio: GSU _______, Unit Aux ______, Station Aux ______, Other Aux ______
- Transformer Tap Setting: GSU _______, Unit Aux ______, Station Aux ______, Other Aux ______
- Transformer Impedance: GSU ________; Transformer X/R ratio: GSU _______

- Generator or Exciter Field Current (synchronous only): Start __________, End ____________
- Ambient conditions at the end of the verification period:

  Air or inlet temperature: _________ Humidity: _________

  Cooling water temperature: _________ Stator temperature: ____________

  Other data as applicable: _________

- Generator ~~hydrogen~~ cooling gas pressure at time of test (if applicable) _____________

~~Date that data shown in last verification column in table above was taken~~ _____________

~~Remarks :~~

- ~~Note:~~ If the ~~verification value~~ staged test/operational data did not reach ~~the thermal~~ capability curve (D-curve), describe the ~~reason~~limiting factor.

Testing Remarks:

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

This is the first draft of the proposed standard for a formal 45-day comment period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 20, 2021
SAR posted for comment	March 4 – April 2, 2021

Anticipated Actions	Date
45-day formal or informal comment period with ballot	September – November 2022
45-day formal or informal comment period with additional ballot	February – April 2023
10-day final ballot	May 2023
Board adoption	August 2023

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:** Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

2. **Number:** ~~PRC-019-2~~PRC-019-3

3. **Purpose:** To verify coordination of generating unit or Facility ~~or synchronous condenser~~ voltage regulating controls, limit functions, equipment capabilities ~~and Protection System settings~~, and protective functions.

4. **Applicability:**

   4.1. Functional Entities

   4.1.1 Generator Owner

   4.1.2 Transmission Owner ~~that owns synchronous condenser(s)~~

   4.2. Facilities: For the purpose of this standard, the term, "applicable Facility" or "Facility" shall mean any one of the following:

   4.2.1 Individual generating ~~unit greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System.~~resource identified through Inclusion I2 of the BES definition.

   4.2.2 Generating plant/Facility identified through Inclusion I2 of the BES definition.

   ~~**4.2.2** Individual synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System.~~

   ~~**4.2.3** Generating plant/ Facility consisting of one or more units that are connected to the Bulk Electric System at a common bus with total generation greater than 75 MVA (gross aggregate nameplate rating).~~

   4.2.3 ~~**4.2.3.1**This includes individual generating units of the dispersed power producing~~ Dynamic reactive resources identified through Inclusion ~~I4 of the Bulk Electric System definition where voltage regulating control for the facility is performed solely at the individual generating unit of the dispersed power producing resources.~~ I5 of the BES definition with a gross (individual or aggregate) nameplate rating greater than 20 MVA including:

   4.2.3.1 Synchronous condenser.

   4.2.4 Inverter-based resource (IBR) generating plant/Facility identified through Inclusion I4 of the BES definition, including:

   4.2.4.1 Individual IBR units;

   4.2.4.2 Collector bus(es) and collector feeder(s);

   4.2.4.3 Static or dynamic reactive compensating devices;

4.2.4.4 Main power transformer (MPT);[1]

4.2.4.5 Generator step-up (GSU) transformer(s);[2]

4.2.5 Any Blackstart Resource.

~~**4.2.4** Any generator, regardless of size, that is a blackstart unit material to and designated as part of a Transmission Operator's restoration plan.~~

5. Effective Date: See the Implementation Plan for ~~PRC-019-2~~PRC-019-3.

B. Requirements and Measures

R1. At a maximum of every ~~five~~ six calendar years, each Generator Owner and Transmission Owner with applicable Facilities shall coordinate[3] the voltage regulating system controls, ~~(including in-service [1]limiters and protection functions)~~ with the applicable equipment capabilities and settings of the applicable ~~Protection System devices and functions~~protective functions.[4] Equipment capabilities, control functions, and protective functions for the applicable Facilities include, but are not limited to those listed in Attachment 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. ~~Assuming~~ For synchronous generators or synchronous condensers, assuming the normal automatic voltage regulator control loop and steady-state system operating conditions, verify the following coordination items ~~for each applicable Facility~~:

1.1.1. The in-service ~~limiters~~ limiter functions[5] are set to operate before the ~~Protection System~~ protective functions of the applicable Facility in order to avoid disconnecting the generator unnecessarily.

1.1.2. The applicable in-service ~~Protection System devices~~ protective functions are set to operate to isolate or de-energize equipment in order to limit the extent of damage when operating conditions exceed equipment capabilities ~~or stability limits.~~.

[1] For the purpose of this standard, the MPT is the power transformer that steps up voltage from the collection system voltage to the nominal transmission/interconnecting system voltage for dispersed power producing resources.

[2] For the purpose of this standard, the GSU is the power transformer that steps up voltage from the individual IBR unit to the nominal collection system voltage for dispersed power producing resources.

[3] As-left settings shall be utilized in a protection and control coordination study.

~~[1] Limiters or protection functions that are installed and activated on the generator or synchronous condenser.~~

[4] A protective function includes an action performed by a Protection System device or an action performed by a control system that replicates the behavior of a Protection System device in order to mitigate the consequences of an event that exceeds equipment design basis.

[5] Limiter functions that are installed and activated on the generator or synchronous condenser.

1.2. For IBR generating Facilities, assuming the voltage control mode is enabled in the power plant controller and/or IBR unit(s)[6] and steady-state system operating conditions, verify the following coordination items:

1.2.1. The in-service control functions of the power plant controller are set to operate before the protective functions of the applicable Facilities in order to avoid disconnecting any of the Facilities listed under Section 4.2.4 unnecessarily.

1.2.2. The in-service control functions of IBR unit(s) are set to operate before protective functions of the applicable Facilities in order to avoid disconnecting any of Facilities listed under Section 4.2.4 unnecessarily.

1.2.3. The applicable in-service protective functions are set to operate to isolate or de-energize equipment in order to limit the extent of damage when operating conditions exceed equipment capabilities.

M1. Each Generator Owner and Transmission Owner with applicable Facilities will have evidence such as a graphical representation(s) of coordination including a P-Q Diagram, R-X Diagram, Inverse Time Diagram, equivalent tables, steady-state calculations, dynamic simulation studies, or other evidence that it performed a coordination study as specified in Requirement R1. This evidence should include dated documentation that demonstrates the coordination was performed.

R2. ~~Within 90 calendar days following the identification or~~ Each Generator Owner and Transmission Owner shall perform the coordination described in Requirement R1 prior to implementation of systems, equipment ~~or setting~~ , or settings changes that will affect the coordination described in Requirement R1~~, each Generator Owner and Transmission Owner with applicable Facilities shall perform the coordination as described in Requirement R1~~; and update associated coordination documentation within 90 calendar days after the return to in-service date. These possible systems, equipment or settings changes include, but are not limited to~~-~~, the following~~–~~: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*~~:~~

- Voltage regulating settings or equipment changes;
- ~~Protection System~~ Protective function settings or component changes;
- ~~Generating~~ IBR unit, synchronous generator or synchronous condenser equipment capability changes; ~~or~~
- ~~Generator~~ IBR unit, synchronous generator or synchronous condenser step-up transformer changes~~.~~;
- IBR unit control system firmware or settings changes; or

[6] IBR unit includes the inverter, converter, or wind turbine generator.

- Power plant controller firmware or settings changes.

~~C. Measures~~

~~**M1.** Each Generator Owner and Transmission Owner with applicable Facilities will have evidence (such as examples provided in PRC-019 Section G) that it coordinated the voltage regulating system controls, including in-service [2] limiters and protection functions, with the applicable equipment capabilities and settings of the applicable Protection System devices and functions as specified in Requirement R1. This evidence should include dated documentation that demonstrates the coordination was performed.~~

M2. Each Generator Owner and Transmission Owner with applicable Facilities will have evidence of the coordination study required by the events listed in Requirement R2. This evidence should include dated documentation that demonstrates ~~the specified intervals in~~ Requirement R2 ~~have~~ has been met.

~~[2] Limiters or protection functions that are installed and activated on the generator or synchronous condenser.~~

C. ~~D.~~ 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.
    ~~The Regional Entity shall serve as the Compliance enforcement authority unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional entity approved by FERC or other applicable governmental authority shall serve as the CEA.~~

    ~~1.2. **Evidence Retention**~~

    1.2. **Evidence Retention:** The following evidence retention ~~periods~~ period(s) identify ~~a~~ 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 ~~compliance~~ audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

    The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

    - The Generator Owner and Transmission owner shall keep data or evidence of Requirement R1 of the most recent coordination study.
    - The Generator Owner and Transmission Owner shall ~~retain evidence of compliance with Requirements R1 and R2, Measures M1 and M2 for six years.~~ keep data or evidence of Requirement R2 of the most recent coordination study.

    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.

~~If a Generator Owner or Transmission Owner is found non-compliant, the entity shall keep information related to the non-compliance until mitigation is complete and approved or for the time period specified above, whichever is longer.~~

~~The Compliance Enforcement Authority shall keep the last periodic audit report and all requested and submitted subsequent audit records.~~

~~**1.3. Compliance Monitoring and Assessment Processes**~~

~~Compliance Audit~~

~~Self-Certification~~

~~Spot Checking~~

~~Compliance Investigation~~

~~Self-Reporting~~

~~Complaint~~

~~**1.4. Additional Compliance Information**~~

~~None~~

~~2.~~Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Generator Owner or Transmission Owner coordinated equipment capabilities, ~~limiters~~control functions, and protection specified in Requirement R1 ~~more than 5 calendar years but less than or equal to 5 calendar years plus 4~~ between 6 years (72 months) and 76 months after the previous coordination.	The Generator Owner or Transmission Owner coordinated equipment capabilities, ~~limiters~~control functions, and protection specified in Requirement R1 ~~more than 5 calendar years plus 4 months but less than or equal to 5 calendar years plus 8~~ between 77 and 81 months after the previous coordination.	The Generator Owner or Transmission Owner coordinated equipment capabilities, ~~limiters~~control functions, and protection specified in Requirement R1 ~~more than 5 calendar years plus 8 months but less than or equal to 5 calendar years plus 12~~ between 82 and 86 months after the previous coordination.	The Generator Owner or Transmission Owner ~~failed to coordinate~~ coordinated equipment capabilities, ~~limiters~~control functions, and protection specified in Requirement R1 ~~within 5 calendar years plus 12~~ more than 86 months after the previous coordination. OR The Generator Owner or Transmission Owner failed to coordinate equipment capabilities, limiters, and protection as specified in Requirement R1.
~~R2~~R2.	The Generator Owner or Transmission Owner ~~coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 90 calendar days but less than or equal to 100 calendar days following the identification or implementation of a change in equipment or settings that affected the coordination.~~updated	The Generator Owner or Transmission Owner ~~coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 100 calendar days but less than or equal to 110 calendar days following the identification or implementation of a change in equipment or settings that affected the coordination.~~	The Generator Owner or Transmission Owner ~~coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 110 calendar days but less than or equal to 120 calendar days following the identification or implementation of a change in equipment or settings that affected the coordination.~~updated	The Generator Owner or Transmission Owner failed to update associated coordination documentation as specified in Requirement R2 within 151 calendar days after return to in-service date. OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	associated coordination documentation as specified in Requirement R2 between 91 and 120 calendar days after return to in-service date.	updated associated coordination documentation as specified in Requirement R2 between 121 and 150 calendar days after return to in-service date.	associated coordination documentation as specified in Requirement R2 between 151 and 180 calendar days after return to in-service date.	The Generator Owner or Transmission Owner failed to coordinate equipment capabilities, limiters, and protection specified in Requirement R1 ~~within 120 calendar days following the identification or implementation of~~ prior to the implementing a change in equipment or settings that affected the coordination.

D. ~~E.~~ Regional Variances

None.

E. ~~F.~~ Associated Documents

"Underexcited Operation of Turbo Generators", AIEE Proceedings T Section 881, Volume 67, 1948, Appendix 1, C. G. Adams and J. B. McClure.

~~,~~"Protective Relaying For Power Generation Systems", Boca Raton, FL, Taylor & Francis, 2006, Reimert, Donald

"Coordination of Generator Protection with Generator Excitation Control and Generator Capability", a report of Working Group J5 of the IEEE PSRC Rotating Machinery Subcommittee

"IEEE C37.102-2006 IEEE Guide for AC Generator Protection"

"IEEE C50.13-2005 IEEE Standard for Cylindrical-Rotor 50 Hz and 60 Hz Synchronous Generators Rated 10 MVA and Above"

"IEEE C37.106 IEEE Guide for Abnormal Frequency Protection for Power Generating Plants"

Version History

Version	Date	Action	Change Tracking
1	February 7, 2013	Adopted by NERC Board of Trustees	New
1	March 20, 2014	FERC Order issued approving PRC-019-1. (Order becomes effective on 7/1/16.)	
2	February 12, 2015	Adopted by NERC Board of Trustees	Standard revised in Project 2014-01: Applicability revised to clarify application of requirements to BES dispersed power producing resources
2	May 29, 2015	FERC Letter Order in Docket No. RD15-3-000 approving PRC-019-2	Modifications to adjust the applicability to owners of dispersed generation resources.
3	TBD	Adopted by NERC Board of Trustees	Standard revised in Project 2021-01

~~G. Reference~~

~~Examples of Coordination~~

~~The evidence of coordination associated with Requirement R1 may be in the form of:~~

- ~~P-Q Diagram (Example in Attachment 1), or~~

~~•R-X Diagram (Example in~~ Attachment ~~2), or~~1: Equipment Capabilities, Types of Limiters, and Protective Functions

NOTE: This standard does not require the installation or activation of any of the limiter or protection functions for synchronous generation or IBR.

- ~~Inverse Time Diagram (Example in Attachment 3) or,~~
- ~~Equivalent tables or other evidence~~

A. ~~This evidence should include the~~ Synchronous generation equipment capabilities ~~and the operating region for the limiters and protection functions~~, control functions, and protective functions, which shall be coordinated if enabled, include but are not limited to:

- Synchronous generator/condenser reactive capabilities;

~~Equipment limits, types of limiters and protection functions which could be coordinated include (but are not limited to):~~

- Field over-excitation limiter and associated ~~protection functions.~~protective function;
- ~~Inverter over current limit and associated protection functions.~~
- Field under-excitation limiter and associated ~~protection functions.~~protective function;
- ~~Generator or synchronous condenser reactive capabilities.~~
- Volts per hertz limiter and associated ~~protection functions.~~protective function;
- Stator over-voltage protection system settings~~.~~;
- ~~Generator~~ Synchronous generator/condenser and transformer volts per hertz capability~~.~~;
- Time vs. field current or time vs. stator current~~.~~; and
- Distributed control system (DCS) voltage/VAR limit settings.

B. IBR generating Facility equipment capabilities, control functions, and protective functions, which shall be coordinated if enabled, include but are not limited to:

- Transformer overvoltage protective function;
- Transformer undervoltage protective function;
- Transformer volts per hertz capability and protective function;
- Collector bus overvoltage protective function;

- Collector bus undervoltage protective function;
- Reactive compensating devices voltage control functions;
- Reactive compensating devices voltage protective function;
- Collector feeder phase overvoltage protective function;
- Collector feeder phase undervoltage protective function;
- Collector feeder overcurrent limiter;
- IBR unit phase lock loop protective function;
- IBR unit overcurrent limiter;
- IBR unit momentary cessation (cease current injection) protective function;
- IBR unit phase overvoltage protective function;
- IBR unit phase undervoltage protective function; and
- IBR unit phase overcurrent protective function.

~~**NOTE:** This listing is for reference only.~~ ~~This standard does not require the installation or activation of any of the above limiter or protection functions.~~

~~For this example, the Steady State Stability Limit (SSSL) is the limit to synchronous stability in the under-excited region with fixed field current.~~

~~On a P-Q diagram using X_d as the direct axis saturated synchronous reactance of the generator, X_s as the equivalent reactance between the generator terminals and the "infinite bus" including the reactance of the generator step-up transformer and V_g as the generator terminal voltage (all values in per-unit), the SSSL can be calculated as an arc with the center on the Q axis with the magnitude of the center and radius described by the following equations~~

~~$C = V^2{}_g/2*(1/X_s-1/X_d)$~~

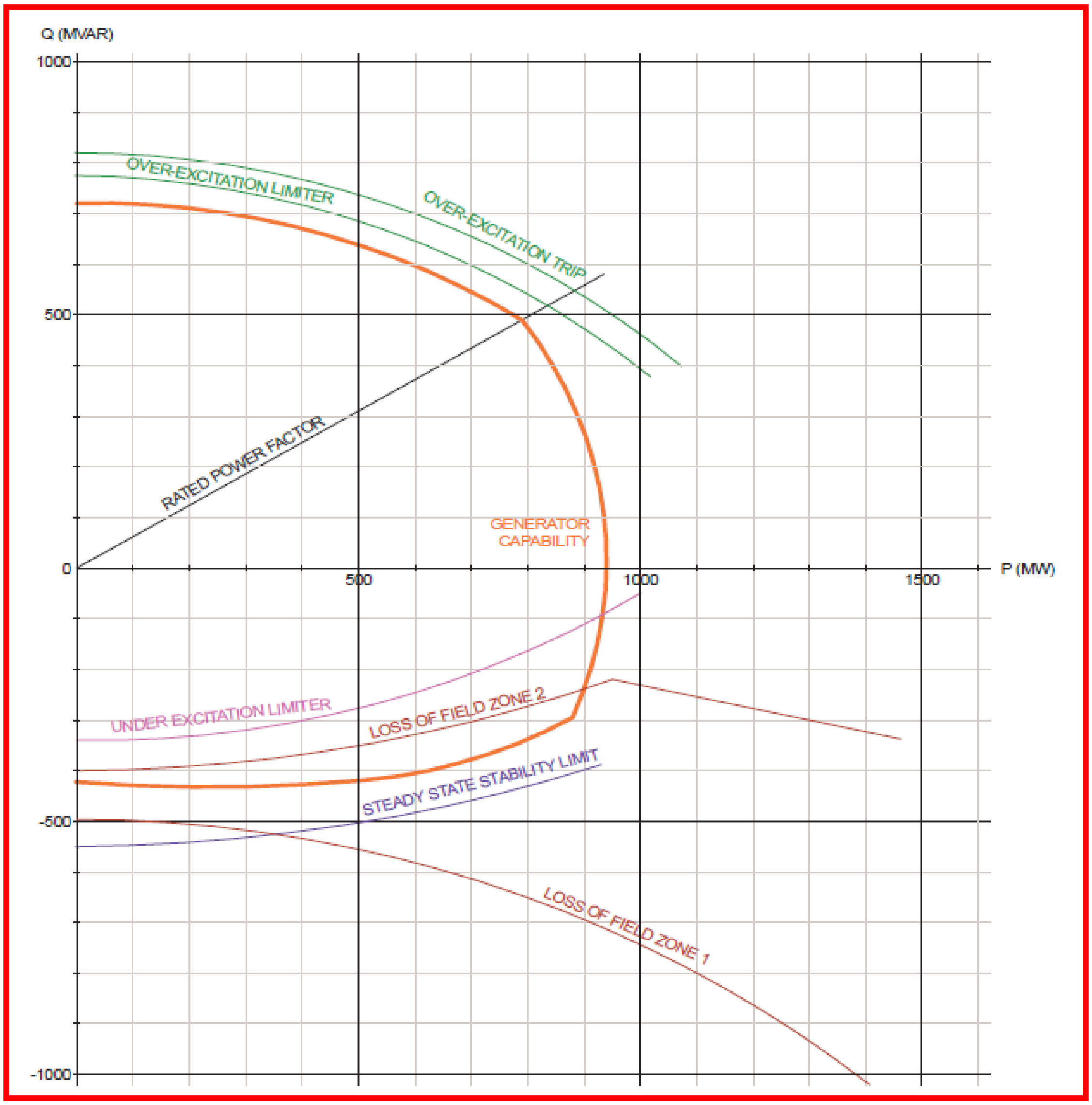
~~$R = V^2{}_g/2*(1/X_s+1/X_d)$~~

~~On an R-X diagram using X_d as the direct axis saturated synchronous reactance of the generator, and X_s as the equivalent reactance between the generator terminals and the "infinite bus" including the reactance of the generator step-up transformer the SSSL is an arc with the center on the X axis with the center and radius described by the following equations:~~

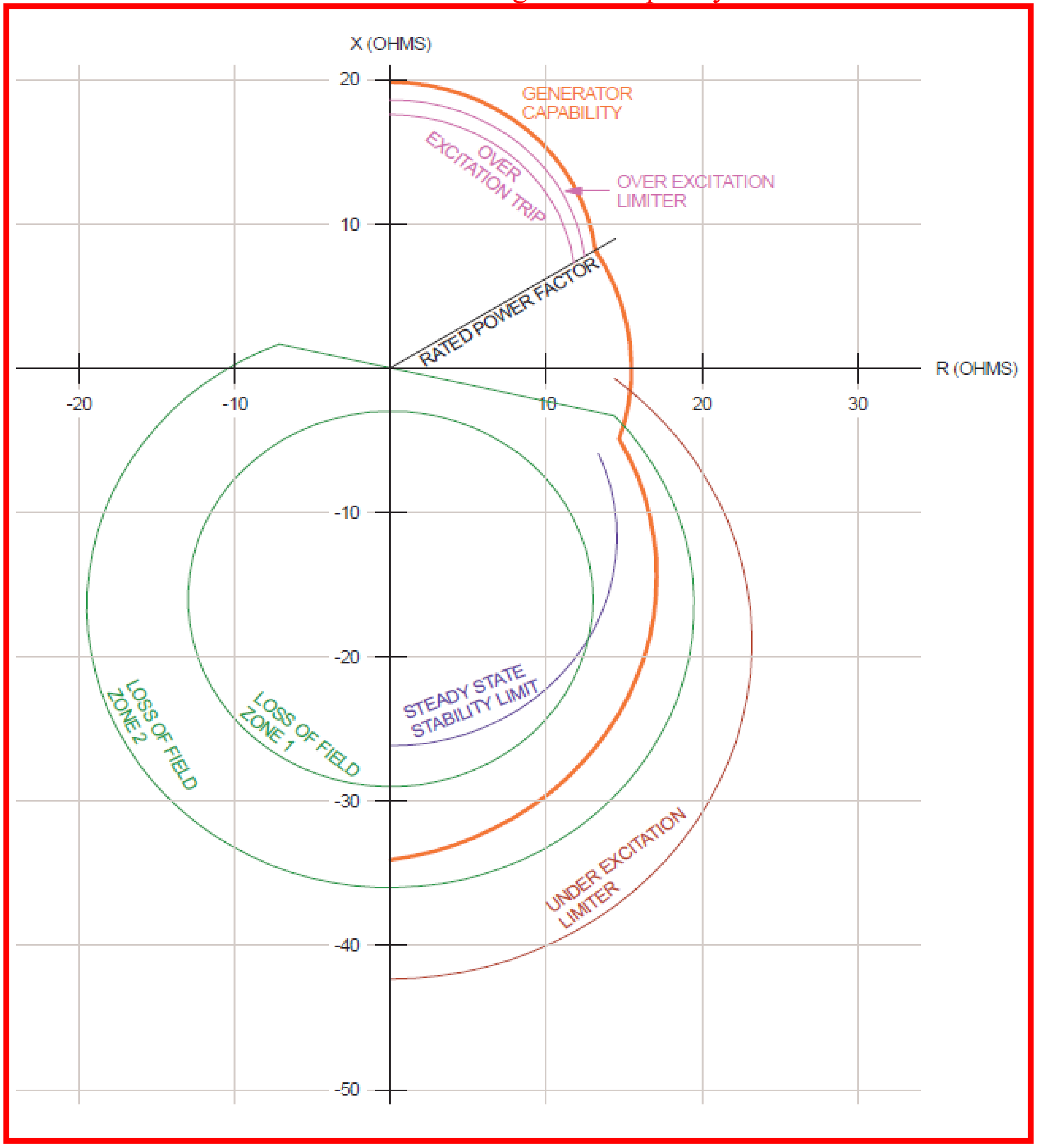
~~$C = (X_d-X_s)/2$~~

~~$R = (X_d+X_s)/2$~~

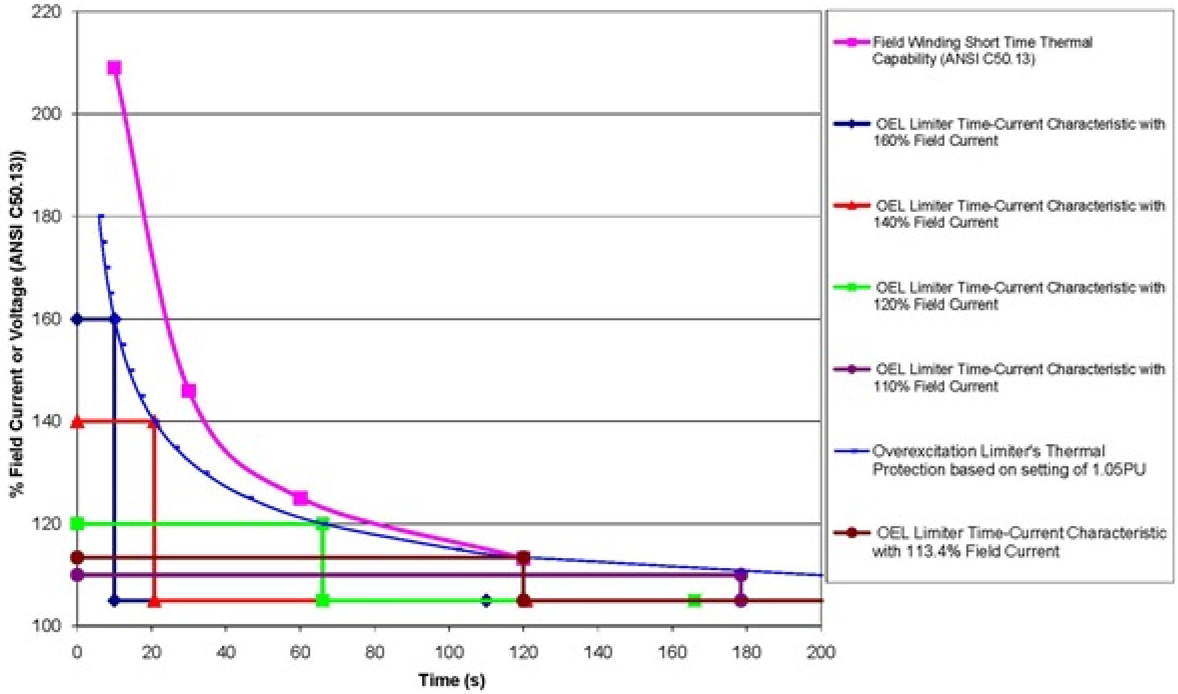
~~Section G Attachment 1 – Example of Capabilities, Limiters and Protection on a P-Q Diagram at nominal voltage and frequency~~



~~Section G Attachment 2 – Example of Capabilities, Limiters, and Protection on an R-X Diagram at nominal voltage and frequency~~



~~Section G Attachment 3 - Example of Capabilities, Limiters, and Protection on an Inverse Time Characteristic Plot~~


% Field Current or Voltage (ANSI C50.13))
Time (s)
220
200
180
160
140
120
100
0
20
40
60
80
100
120
140
160
180
200
Field Winding Short Time Thermal Capability (ANSI C50.13)
OEL Limiter Time-Current Characteristic with 160% Field Current
OEL Limiter Time-Current Characteristic with 140% Field Current
OEL Limiter Time-Current Characteristic with 120% Field Current
OEL Limiter Time-Current Characteristic with 110% Field Current
Overexcitation Limiter's Thermal Protection based on setting of 1.05PU
OEL Limiter Time-Current Characteristic with 113.4% Field Current

~~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 Facilities section 4.2.3.1~~

~~For those dispersed power producing facilities that only perform voltage regulating control at the individual generating unit level, the SDT believes that coordination should take place at the individual generating unit level of the dispersed power producing resource. These facilities need to consider the Protection Systems at the individual units and their compatibility with the reactive and voltage limitations of the units. Where voltage regulating control is done at an aggregate level, applicability is already included under Facilities section 4.2.3.~~

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

This is the first draft of the proposed standard for a formal 45-day comment period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 20, 2021
SAR posted for comment	March 3 – April 6, 2022
SAR posted for comment	April 14 –May 13, 2021

Anticipated Actions	Date
45-day formal comment period with ballot	October 31, 2022
45-day formal comment period with additional ballot	TBD
10-day final ballot	TBD
Board adoption	TBD

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

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Term(s):

None

A. Introduction

1. ~~Title:~~Title: Generator Operation for Maintaining Network Voltage Schedules

~~2. Number:VAR-002-4.1~~

2. Number: VAR-002-5

3. Purpose: To ensure generators or dispersed power producing resources provide reactive support and voltage control, within generating Facility capabilities, in order to protect equipment and maintain reliable operation of the Interconnection.

4. Applicability:

   4.1. Functional Entities:

      4.1.1. ~~4.1.~~Generator Operator

      4.1.2. ~~4.2.~~Generator Owner

   4.2. Facilities: For the purpose of this standard, the term "generator" means a generator-owned facility capable of controlling voltage.

5. Effective ~~Dates~~Date: See Implementation Plan for VAR-002-5.

~~See Implementation Plan.~~

B. Requirements and Measures

R1. ~~**R1.**~~ The Generator Operator shall operate each generator or dispersed power producing resource connected to the interconnected transmission system in the automatic voltage control mode (with its automatic voltage regulator (AVR) or volt/VAR controller(s) in service and controlling voltage) or in a different control mode as instructed by the Transmission Operator unless: 1) the generator ~~is~~ or dispersed power producing resources are exempted by the Transmission Operator, or 2) the Generator Operator has notified the Transmission Operator of one of the following: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

- That the generator or dispersed power producing resource is being operated in~~-~~ ~~start-up,[1] shutdown,[2]~~ start- up[1], shutdown[2], or testing mode pursuant to a Real-time communication or a procedure that was previously provided to the Transmission Operator; or
- That the generator or dispersed power producing resource is not being operated in automatic voltage control mode or in the control mode that was instructed by the Transmission Operator for a reason other than start-up, shutdown, or testing.

M1. ~~**M1.**~~ The Generator Operator ~~shall~~ will have evidence to show that it notified its associated Transmission Operator any time it failed to operate a generator or dispersed power producing resource in the automatic voltage control mode or in a different control mode as specified in Requirement R1. If a generator or dispersed power producing resource is being started up or shut down with the automatic voltage control off, or is being tested, and no notification of the AVR status is made to the Transmission Operator, the Generator Operator will have evidence that it notified the Transmission Operator of its procedure for placing the unit into automatic voltage control mode as required in Requirement R1. Such evidence may include, but is not limited to, dated evidence of transmittal of the procedure such as an electronic message or a transmittal letter with the procedure included or attached. If a generator ~~is exempted, the Generator Operator shall also have evidence that the generator~~ or dispersed power producing resource is exempted from ~~being in~~ automatic voltage control mode (with its AVR or volt/VAR controller(s) in service and controlling voltage)~~.~~, the Generator Operator will maintain evidence of an exception.

~~[1]Start-upisdeemedtohaveendedwhenthegeneratorisrampeduptoitsminimumcontinuouslysustainableloadandthe generatorispreparedforcontinuousoperation.~~

~~[2]Shutdownisdeemedtobeginwhenthegeneratorisrampeddowntoitsminimumcontinuouslysustainableloadandthegenerator is prepared to gooffline.~~

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[1] Start-up is deemed to have ended when the generator or dispersed power producing resource is ramped up to its minimum continuously sustainable load and the generator is prepared for continuous operation.

[2] Shutdown is deemed to begin when the generator or dispersed power producing resource is ramped down to its minimum continuously sustainable load and the generator or dispersed power producing resource is prepared to go offline.

R2. ~~R2.~~Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator or dispersed power producing resource voltage or Reactive Power ~~schedule[3]~~ schedule[3] (within each generating Facility's ~~capabilities[4]~~capabilities[4]) provided by the Transmission Operator, or otherwise shall meet the conditions of notification for deviations from the voltage or Reactive Power schedule provided by the Transmission Operator. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

2.1. When a generator's AVR or volt/VAR controller(s) is out of service or the generator does not have an AVR, the Generator Operator shall use an alternative method to control the generator reactive output to meet the voltage or Reactive Power schedule provided by the Transmission Operator or provide an explanation if control capability is limited.

2.2. When instructed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.

2.3. Generator Operators that do not monitor the voltage at the location specified in their voltage schedule shall have a methodology for converting the scheduled voltage ~~specified by the Transmission Operator~~ to the voltage point being monitored by the Generator Operator.

M2. ~~M2.~~In order to identify when a generator or dispersed power producing resource is deviating from its schedule, the Generator Operator will monitor voltage based on existing equipment at its Facility. The Generator Operator ~~shall~~ will have evidence to show that the generator or dispersed power producing resource maintained the voltage or Reactive Power schedule provided by the Transmission Operator~~, or shall~~ or will have evidence of meeting the conditions of notification for deviations from the voltage or Reactive Power schedule provided by the Transmission Operator.

Evidence may include, but is not limited to, operator logs, SCADA data, phone logs, and any other notifications that would alert the Transmission Operator or otherwise demonstrate that the Generator Operator complied with the Transmission Operator's instructions for addressing deviations from the voltage or Reactive Power schedule.

For Part 2.1, when a generator's AVR or volt/VAR controller(s) is out of service or the generator or dispersed power producing resource does not have an AVR, a Generator Operator ~~shall~~ will have evidence to show an alternative method was used to control the generator reactive output to meet the voltage or Reactive Power schedule provided by the Transmission Operator.

For Part 2.2, the Generator Operator ~~shall~~ will have evidence that it complied with the Transmission Operator's instructions to modify its voltage or provided an explanation

[3] The voltage or Reactive Power schedule is a target value with a tolerance band, or a voltage or Reactive Power range communicated by the Transmission Operator to the Generator Operator.
[4] Generating Facility capability may be established by test or other means and may not be sufficient at times to pull the system voltage within the schedule tolerance band. Also, when a generator is operating in manual control, Reactive Power capability may change,based on stability considerations.

to the Transmission Operator of why the Generator Operator was unable to comply with the instruction. Evidence may include, but is not limited to, operator logs, SCADA data, and phone logs.

For Part 2.3, for Generator Operators that do not monitor the voltage at the location specified on the voltage schedule, the Generator Operator ~~shall~~ will demonstrate the methodology for converting the scheduled voltage specified by the Transmission Operator to the voltage point being monitored by the Generator Operator.

~~[3] ThevoltageorReactivePowerscheduleisatargetvaluewithatolerancebandoravoltageorReactivePowerrangecommunicated bytheTransmissionOperatortotheGeneratorOperator.~~

~~[4] Generating Facility capability may be established by test or other means, and may not be sufficient at times to pull the system voltagewithintheschedulettolerанceband.Also,whenageneratorisoperatinginmanualcontrol,ReactivePowercapability may changebased on stability considerations.~~

R3. ~~**R3.**~~Each Generator Operator shall notify~~-~~, in a mutually-agreeable format[5], its associated Transmission Operator of a status or functionality change ~~on the AVR~~of applicable AVR, volt/VAR controller(s), power system stabilizer, or alternative voltage controlling device which degrades/restores its ability to automatically control voltage. Status or functionality change notifications shall be made within 30 minutes of ~~the~~ becoming aware of a change. If the status has been restored within 30 minutes of~~-~~ ~~such~~ becoming aware of the change, then the Generator Operator is not required to notify the Transmission Operator of the status change. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M3. ~~**M3.**~~The Generator Operator ~~shall~~ will have evidence it notified its associated Transmission Operator within 30 minutes of ~~any status~~ becoming aware of a change identified in Requirement R3~~. If the status~~ and evidence of the mutually-agreeable format such as any of the following: emails, voltage schedule documentation, or reliability data specification. If the status or functionality change has been restored within the first 30 minutes of becoming aware of a change, no notification is necessary~~-~~.

R4. ~~**R4.**~~Each Generator Operator shall notify~~-~~, in a mutually-agreeable format, its associated Transmission Operator within 30 minutes of becoming aware of a change in reactive capability that exceeds the threshold for notification due to factors other than ~~a status change described~~ specified in Requirement R3. If the capability has been restored within 30 minutes of the Generator Operator becoming aware of such change, then the Generator Operator is not required to notify the Transmission Operator of the change in reactive capability. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

[5] Mutually-agreeable format for VAR-002-5 - notification should include the communication method (e.g., voice, data, email, etc.) and the threshold of degradation if a generator or dispersed power producing resource has a voltage control methodology which may become partially inoperative.

- ~~Reporting of status or capability changes as stated in Requirement R4 is not applicable to the individual generating units of dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition.~~

M4. ~~**M4.**The Generator Operator shall~~ The Generator Operator will have evidence it notified its associated Transmission Operator within 30 minutes of becoming aware of a change in reactive capability in accordance with Requirement R4. If the capability has been restored within the first 30 minutes, no notification is necessary. The Generator Operator will provide evidence of coordination with the Transmission Operator to identify a mutually-agreeable format, such as any of the following: emails, voltage schedule documentation, or reliability data specification.

R5. ~~**R5.**~~The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request. *[Violation Risk Factor: Lower] [Time Horizon:* ~~*Real-time*~~ *Operations Planning]*

5.1. For generator step-up and auxiliary ~~transformers5~~ transformers[6] with primary voltages equal to or greater than the generator terminal voltage:

5.1.1. Tap settings.

5.1.2. Available ~~fixed~~ tap ranges.

5.1.3. Impedance data~~.**M5**~~.

M5. The Generator Owner shall have evidence it provided its associated Transmission Operator and Transmission Planner with information on its step-up and auxiliary transformers as required in Requirement R5, Part 5.1.1 through Part 5.1.3 within 30 calendar days.

~~[5]Fordispersedpowerproducingresourcesidentifiedthrough InclusionI4oftheBulkElectricSystemdefinition,thisrequirement appliesonlytothosetransformersthathaveatleastonewindingatavoltageof100kVorabove.~~

R6. ~~**R6.**~~After consultation with the Transmission Operator regarding necessary generator owned step-up transformer tap changes, the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator, unless such action would violate safety, an ~~equipment rating~~Equipment Rating, a regulatory requirement, or a statutory requirement. *[Violation Risk Factor: Lower] [Time Horizon:* ~~*Real-time*~~ *Operations Planning]*

6.1. ~~**6.1.**~~ If the Generator Owner cannot comply with the Transmission Operator's specifications, the Generator Owner shall notify the Transmission Operator and shall provide the technical justification.

[6] For dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies only to those transformers that have at least one winding at a voltage of 100 kV or above.

M6. ~~**M6.**~~The Generator Owner ~~shall~~ will have evidence that its step-up transformer taps were modified per the Transmission Operator's documentation in accordance with Requirement R6. The Generator Owner ~~shall~~ will have evidence that it notified its associated Transmission Operator when it could not comply with the Transmission Operator's step-up transformer tap specifications in accordance with Requirement R6, Part 6.1.

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.

~~As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" refers to NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC ReliabilityStandards.~~

1.2. Evidence Retention: The following evidence retention ~~periods~~ period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full~~-~~-time period since the last audit.

The Generator Owner shall keep its latest version of documentation on its step-up and auxiliary transformers. The Generator Operator shall maintain all other evidence for the current and previous calendar year.

The Compliance Monitor shall retain any audit data for three years.

~~***1.3. Compliance Monitoring and AssessmentProcesses:***~~

1.3. Compliance Monitoring and Enforcement Program: As defined in the NERC Rules of Procedure, "Compliance Monitoring and ~~Assessment Processes~~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~~Reliability Standard.

~~***1.4. Additional ComplianceInformation:***~~

Violation Severity Levels

~~None.~~

~~*Table of Compliance Elements*~~

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
~~R1~~ R1.	~~Real-time Operatio~~	~~Medium~~	N/A	N/A	N/A	Unless exempted, the Generator Operator did not operate each generator or dispersed power producing resource connected to the interconnected transmission system in the automatic voltage control mode or in a different control mode as instructed by the Transmission Operator, and failed to provide the required notifications to Transmission Operator as identified in Requirement R1.

R #	~~Time Horizons~~	~~VRF~~	Violation Severity Levels				
	~~R #~~	~~Time Horizon~~	~~VRF~~	~~Violation Severity Levels~~			
				~~Lower VSL~~	~~Moderate VS~~		~~Severe VSL~~

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels				
					~~L~~		
	R2	~~Real-time Operations~~	~~Medium~~ R2.	N/A	N/A	The Generator Operator did maintain vol	The Generator Operator did not maintain the voltage or Reactive Power schedule as instructed by the Transmission Operator and did not make the necessary notifications required by the Transmission Operator. OR The Generator Operator did not have an operating AVR or volt/VAR controller(s), and the responsible entity did not use an alternative method for controlling voltage. OR The Generator Operator did not modify voltage when directed, and the Responsible Entity did not provide any explanation.

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels				
						tage or Reactive Power schedule, but did	

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels				
						not have a conversion methodology	

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels				
						when it monitors voltage at a location diff	

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels				
						erent from the schedule provided by the	

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels				
						Transmission Operator.	
							~~OR~~
							~~The Generator Operator did not modify voltage when directed, and the responsible entity did not provide any explanation.~~
	~~R3~~	~~Real~~	~~Me~~		N/A	N/A	The Generator Operator did not make the required notification within 30 minutes of the status change.

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels				
		~~-time Operations~~	~~dium~~ R3.	N/A			
	~~R #~~	~~Time Horizon~~	~~VRF~~	~~Violation Severity Levels~~			
				~~Lower V~~	~~Modera~~		~~Severe VSL~~

R #	~~Time Horizon~~	~~VRF~~	**Violation Severity Levels**				
				~~SL~~	~~teVSL~~		
	~~R4~~	~~Real-time Operations~~	~~Medium~~ R4.	N/A	N/A	N/A	The Generator Operator did not make the required notification within 30 minutes of becoming aware of the capability change.
	~~R5~~	~~Real-time Ope~~	~~Lower~~ R5.	N/A	N/A	The Generator Owner failed to provide its	The Generator Owner failed to provide to its associated Transmission Operator and Transmission Planner two or more of the types of data specified in Requirement R5 Parts 5.1.1, 5.1.2, and 5.1.3.

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels				
		~~rations~~				associated Transmission Operator and Transmission Planner one of the types of data specified in Requirement R5 Parts 5.1.1,	

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels				
						5.1.2, and 5.1.3.	
	~~R #~~	~~Time Horizon~~	~~VRF~~	~~Violation Severity Levels~~			
				~~Lower VSL~~	~~Moderate VSL~~		~~Severe VSL~~

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels				
	~~R6~~	~~Real-time Operations~~	~~Lower~~ R6.	N/A	N/A	N/A	The Generator Owner did not ensure the tap changes were made according to the Transmission Operator's specifications. OR The Generator Owner failed to perform the tap changes, and the Generator Owner did not provide technical justification for why it could not comply with the Transmission Operator specifications.

D. Regional Variances

~~None.~~

E. ~~*Interpretations*~~

None.

E. ~~F.~~Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	5/1/2006	Added "(R2)" to the end of levels on non-compliance 2.1.2, 2.2.2, 2.3.2, ~~and2.4.3~~and 2.4.3.	July 5, 2006
1a	12/19/2007	Added Appendix 1 – Interpretation of R1 and R2 approved by BOT on August 1, 2007.	Revised
1a	1/16/2007	In Section A.2., Added "a" to end of standard number. Section F: added "1."; and added date.	Errata
~~1.1a~~	~~10/29/2008~~	~~BOT adopted errata changes; updated version number to "1.1a"~~	~~Errata~~
1.1b	3/3/2009	Added Appendix 2 – Interpretation of VAR-002-1.1a approved by BOT on February 10, 2009.	Revised
2b	4/16/2013	Revised R1 to address an Interpretation Request. Also added previously approved VRFs, Time Horizons and VSLs. Revised R2 to address consistency issue	Revised

		with ~~VAR-001-2~~VAR001-2, R4. FERC Order issued approving ~~VAR-002-2b~~VAR002-2b.		
3	5/5/2014	Revised under Project 2013-04 to address outstanding Order 693 directives.	Revised	
3	5/7/2014	Adopted by NERC Board of Trustees.		
3	8/1/2014	Approved by FERC in docket ~~RD14-11-000~~RD14-11-000.		
4	8/27/2014	Revised under Project 2014-01 to clarify applicability of Requirements to BES dispersed power producing resources.	Revised	
			~~BES dispersed power producing resources.~~	
	4	11/13/2014	Adopted by NERC Board of Trustees.	
	4	5/29/2015	FERC Letter Order in Docket No. RD15- 3-000 approving VAR-002-4.	
	4.1	~~June 14,~~ 6/14/2017	Project 2016-EPR-02 errata recommendations.	Errata

	4.1	~~August 10,~~ 8/10/2017	Adopted by the NERC Board of Trustees.	Errata
	4.1	~~September 26,~~9/26/2017	FERC Letter Order issued approving VAR-002-4.1 RD17-7-000.	
5	TBD	Revised under Project 2021-02 to clarify applicability of Requirements to BES dispersed power producing resources and to address recommendations from Project 2016-EPR-02.	Revised	

~~Guidelines and Technical Basis~~

~~Rationale:~~

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

~~Rationale for R1:~~

~~This requirement has been maintained due to the importance of running a unit with its automatic voltage regulator (AVR) in service and in either voltage controlling mode or the mode instructed by the TOP. However, the requirement has been modified to allow for testing, and the measure has been updated to include some of the evidence that can be used for compliance purposes.~~

~~Rationale for R2:~~

~~Requirement R2 details how a Generator Operator (GOP) operates its generator(s) to provide voltage support and when the GOP is expected to notify the Transmission Operator (TOP). In an effort to remove prescriptive notification requirements for the entire continent, the VAR-002-3 standard drafting team (SDT) opted to allow each TOP to determine the notification requirements for each of its respective GOPs based on system requirements. Additionally, a new Part 2.3 has been added to detail that each GOP may monitor voltage by using its existing facility equipment.~~

~~Conversion Methodology: There are many ways to convert the voltage schedule from one voltage level to another. Some entities may choose to develop voltage regulation curves for their transformers; others may choose to do a straight ratio conversion; others may choose~~

~~an entirely different methodology. All of these methods have technical challenges, but the studies performed by the TOP, which consider N-1 and credible N-2 contingencies, should compensate for the error introduced by these methodologies, and the TOP possesses the authority to direct the GOP to modify its output if its performance is not satisfactory. During a significant system event, such as a voltage collapse, even a generation unit in automatic voltage control that controls based on the low-side of the generator step-up transformer should see the event on the low-side of the generator step-up transformer and respond accordingly.~~

~~Voltage Schedule Tolerances: The bandwidth that accompanies the voltage target in a voltage schedule should reflect the anticipated fluctuation in voltage at the GOP's Facility during normal operations and be based on the TOP's assessment of N-1 and credible N-2 system contingencies. The voltage schedule's bandwidth should not be confused with the control dead-band that is programmed into a GOP's AVR control system, which should be adjusting the AVR prior to reaching either end of the voltage schedule's bandwidth.~~

~~Rationale for R3:~~

~~This requirement has been modified to limit the notifications required when an AVR goes out of service and quickly comes back in service. Notifications of this type of status change provide little to no benefit to reliability. Thirty (30) minutes have been built into the requirement to allow a GOP time to resolve an issue before having to notify the TOP of a status change. The requirement has~~
~~also been amended to remove the sub-requirement to provide an estimate for the expected duration of the status change.~~

~~Rationale for R4:~~

~~This requirement has been bifurcated from the prior version VAR-002-2b Requirement R3. This requirement allows GOPs to report reactive capability changes after they are made aware of the change. The current standard requires notification as soon as the change occurs, but many GOPs are not aware of a reactive capability change until it has taken place.~~

~~Rationale for Exclusion in R4~~:

~~VAR-002 addresses control and management of reactive resources and provides voltage control where it has an impact on the BES. For dispersed power producing resources as identified in Inclusion I4, Requirement R4 should not apply at the individual generator level due to the unique characteristics and small scale of individual dispersed power producing resources. In addition, other standards such as proposed TOP-003 require the Generator Operator to provide Real-time data as directed by the TOP.~~

~~Rationale for R5:~~

~~This requirement and corresponding measure have been maintained due to the importance of having accurate tap settings. If the tap setting is not properly set, then the VARs available from that unit can be affected. The prior version of VAR-002-2b, Requirement R4.1.4 (the +/- voltage range with step-change in % for load-tap changing transformers) has been removed. The percentage information was not needed because the tap settings, ranges and impedance are required. Those inputs can be used to~~

~~calculate the step-change percentage if needed.~~

~~Rationale for Exclusion in R5:~~

~~The Transmission Operator and Transmission Planner only need to review tap settings, available fixed tap ranges, impedance data and the +/- voltage range with step-change in % for load-tap changing transformers on main generator step-up unit transformers which connect dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition to their transmission system. The dispersed power producing resources individual generator transformers are not intended, designed or installed to improve voltage performance at the point of interconnection. In addition, the dispersed power producing resources individual generator transformers have traditionally been excluded from Requirement R4 and R5 of VAR- 002-2b (similar requirements are R5 and R6 for VAR-002-3), as they are not used to improve voltage performance at the point of interconnection.~~

~~Rationale for R6:~~

~~This requirement and corresponding measure have been maintained due to the importance of having accurate tap settings. If the tap setting is not properly set, then the VARs available from that unit can be affected.~~

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:	Modifications to CIP-002 and CIP-014		
Date Submitted:	May 26, 2021		
SAR Requester			
Name:	Dean LaForest		
Organization:	ISO New England		
Telephone:	413-387-8132	Email:	dlaforest@iso-ne.com
SAR Type (Check as many as apply)			
☐ New Standard ☒ Revision to Existing Standard ☐ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☐ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☐ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☒ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
This project provides revisions to CIP-002 and CIP-014 to clarify the responsibility of Reliability Coordinators, Planning Coordinators and Transmission Planners in identifying Facilities that warrant consideration under these Reliability Standards. As it relates to the Transmission Planner and Planning Coordinator functions, the language "critical to the derivation of Interconnection Reliability Operating Limits (IROLs)" should be replaced/updated to appropriately identify Facilities that, if somehow compromised, could significantly impact the reliability of the Bulk Electric System (BES). Additionally this project will review the applicability of Facilities identified by the Reliability Coordinator as critical to the derivation of IROLs to CIP-002 and CIP-014.			
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):			
This project provides necessary clarification to identify Facilities identified by Reliability Coordinators, Planning Coordinators and Transmission Planners that warrant consideration under the CIP-002 and CIP-014 Reliability Standards. These clarifications will ensure that responsible entities are provided with the			

Requested information
necessary information to appropriately protect these Facilities, and correctly identify the responsible parties that provide the information applicable to the standards.
Project Scope (Define the parameters of the proposed project):
This project will make conforming changes to CIP-002 and CIP-014 as a result of Standard revisions from Project 2015-09. Project 2015-09 revised the requirements for determining and communicating System Operating Limits (SOLs) and IROLs used in the reliable planning and operation of the BES. These revisions necessitate that CIP-002 and CIP-014 be revised to clarify the Functional Entities responsible for communication of Facilities that warrant consideration under the CIP-002 and CIP-014 Reliability Standards. This will include review of criteria/applicability to determine Facilities identified per Attachment 1 of CIP-002 and the Applicability section of CIP-014 for potential revision for responsible entities. This team will work to coordinate with other ongoing CIP development projects to ensure alignment with any changes to definition or standards and requirements.
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):
Revisions to CIP-002 and CIP-014 to include: (1) Identifying Functional Entities that identify Facilities applicable to CIP-002 and CIP-014. (2) Identifying Functional Entities responsible for the communication of the identified Facilities. (3) Applicability sections to be reviewed and revised accordingly. (4) Determine the appropriate Facilities for application of the CIP standard and include due consideration for those planning events that result in System instability, Cascading, or uncontrolled separation as identified in the PC and TP's Planning Assessment for the Near-Term Transmission Planning Horizon. (5) Determine the appropriateness of the identification of Facilities critical to the derivation of IROLs by the RC.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
Cost impact of implementation of the proposed Standard is dependent upon the method(s) by which a Responsible Entity chooses to meet any additional Requirements. However, a question will be asked during the SAR comment period to ensure cost aspects are considered.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):
Submitter asserts there are no unique characteristics associated with BES facilities that will be impacted by this proposed standard development project.

[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):
Reliability Coordinator, Balancing Authority, Transmission Owner, Transmission Operator, Generator Owner, Generator Operator
Do you know of any consensus building activities[2] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
None.
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so, which standard(s) or project number(s)?
Project 2016-02 Modifications to CIP Standards.
Are there alternatives (e.g., guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.
None at this 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.
☐	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 identified

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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

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

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:	Modifications to CIP-002		
Date Submitted:	10/4/2021		
SAR Requester			
Name:	Latrice Harkness		
Organization:	NERC		
Telephone:	404-446-9728	Email:	latrice.harkness@nerc.net
SAR Type (Check as many as apply)			
☐ New Standard ☒ Revision to Existing Standard ☐ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☐ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☐ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☒ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
The purpose of this project is to ensure that all BES Cyber Systems' associated Cyber Assets are identified for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those Cyber Assets could have on the reliable operation of the BES. Identification and categorization of these Cyber Assets supports appropriate protection against compromises. Without an accurate inventory of associated Cyber Assets, registered entities may fail to deploy appropriate controls to these Cyber Assets, which may lead to misoperation or instability in the BES.			
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):			
Electronic Access Control or Monitoring Systems (EACMS), Physical Access Control Systems (PACS), and Protected Cyber Assets (PCAs), if compromised, pose a threat to their associated BES Cyber System by virtue of: (a) their location within the Electronic Security Perimeter (PCA), or (b) the security control function they perform (EACMS and PACS). This project will ensure the reliable operation of the BES by requiring the identification of these Cyber Assets so that the appropriate controls can be implemented.			

Requested information
Project Scope (Define the parameters of the proposed project):
This project will make revisions to CIP-002 to include the identification and categorization of certain Cyber Assets (EACMS, PACS, and PCAs) associated with high and medium impact BES Cyber Systems.
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):
Revise CIP-002 to include the identification of EACMS, PACS, and PCA.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
Cost impact is unknown at this time. However, a question will be asked during the comment period to ensure cost aspects are considered.
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):
Balancing Authority, Distribution Provider, Generator Operator, Generator Owner, Interchange Coordinator or Interchange Authority, Reliability Coordinator, Transmission Operator, 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.
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)?
Project 2016-02, Project 2021-03
Are there alternatives (e.g., guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.
None.

[1] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.
[2] Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

Reliability Principles	
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.

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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 Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	01/20/2021
SAR posted for comment	06/14/2021 – 07/13/2021

Anticipated Actions	Date
45-day formal or informal comment period with ballot	06/09/2022 – 07/15/2022
45~~XX~~-day formal or informal comment period with additional ballot	09/26~~09~~/2022 – 11~~0~~/09~~17~~/2022
10~~XX~~-day final ballot	12/09/2022 – 01/16/2023
Board adoption	02/09/2023 – 03/15/2023

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):

N/A.

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements
2. **Number:** PRC-002-~~3~~4
3. **Purpose:** To have adequate data available to facilitate analysis of Bulk Electric System (BES) Disturbances.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Reliability Coordinator
     - **4.1.2.** Transmission Owner
     - **4.1.3.** Generator Owner
5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

R1. Each Transmission Owner shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-~~3~~4, Attachment 1.

1.2. Notify the other owners of BES Elements directly connected[1] to those BES buses, ~~if any, within 90-calendar days of completion of Part 1.1,~~ that SER or FR data is required for those BES Elements, only if the Transmission Owner who identified the BES buses in Part 1.1 does not have ~~require~~ SER ~~data and/~~or FR data. This notification is required within 90 calendar days of completion of Part 1.1.

1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners~~, if any,~~ in accordance with Part 1.2~~, and implement the re-evaluated list of BES buses as per the Implementation Plan~~.

M1. The Transmission Owner for Requirement R1, Part 1.1 has a dated (electronic or hard copy) list of BES buses for which SER and FR data is required, identified in accordance with PRC-002-~~3~~4, Attachment 1;~~,~~ has dated (electronic or hard copy) evidence that it notified other owners in accordance with Requirement R1, Part 1.2; and evidence that all BES buses have been re-evaluated within the required intervals under Requirement R1, Part 1.3. ~~The Transmission Owner will also have dated (electronic or hard copy) evidence that it notified other owners in accordance with Requirement R1.~~

[1] For the purposes of this standard, "directly connected" BES elements are BES elements connected at the same voltage level within the same physical location sharing a common ground grid with the BES bus identified under Attachment 1. Transformers that have a low-side operating voltage of less than 100 kV are excluded.

R2. Each Transmission Owner and Generator Owner shall have SER data for circuit breaker position (open/close) for each circuit breaker it owns directly connected ~~directly~~ to the BES buses identified in Requirement R1 and associated with the BES Elements at those BES buses. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M2. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of SER data for circuit breaker position as specified in Requirement R2. Evidence may include, but is not limited to: (1) documents describing the device interconnections and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings; or (3) station drawings.

R3. Each Transmission Owner and Generator Owner shall have FR data to determine the following electrical quantities for each triggered FR for the BES Elements it owns directly connected to the BES buses identified in Requirement R1: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. Phase-to-neutral voltage for each phase of each specified BES bus.

3.2. Each phase current and the residual or neutral current for the following BES Elements:

3.2.1. Transformers that have a low-side operating voltage of 100kV or above.

3.2.2. Transmission Lines.

M3. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of FR data that is sufficient to determine electrical quantities as specified in Requirement R3. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R4. Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R3 that meets the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

4.1. A single record or multiple records that include:

- A pre-trigger record length of at least two cycles and a total record length of at least 30-cycles for the same trigger point, or
- At least two cycles of the pre-trigger data, the first three cycles of the post-trigger data, and the final cycle of the fault as seen by the fault recorder.

4.2. A minimum recording rate of 16 samples per cycle.

4.3. Trigger settings for at least the following:

4.3.1. Neutral (residual) overcurrent.

4.3.2. Phase undervoltage or overcurrent.

M4. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that FR data meets Requirement R4. Evidence may include, but is not limited to: (1) documents describing the device specification (R4, Part 4.2) and device configuration or settings (R4, Parts 4.1 and 4.3), or (2) actual data recordings or derivations.

R5. Each Reliability Coordinator shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

5.1. Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following:

5.1.1. Generating resource(s) with:

5.1.1.1. Gross individual nameplate rating greater than or equal to 500 MVA.

5.1.1.2. Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1,000 MVA.

5.1.2. Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL).

5.1.3. Each terminal of a high voltage direct current (HVDC) circuit with a nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter.

5.1.4. One or more BES Elements that are part of an Interconnection Reliability Operating Limit (IROL).

5.1.5. Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program.

5.2. Identify a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least:

5.2.1. One BES Element; and

5.2.2. One BES Element per 3,000 MW of the Reliability Coordinator's historical simultaneous peak System Demand.

5.3. Notify all owners of identified BES Elements, within 90-calendar days of completion of Part 5.1, that their respective BES Elements require DDR data ~~when requested~~.

5.4. Re-evaluate all BES Elements under its purview at least once every five calendar years in accordance with Parts 5.1 and 5.2, and notify owners in accordance with Part 5.3~~ to implement the re-evaluated list of BES Elements as per the Implementation Plan~~.

M5. The Reliability Coordinator has a dated (electronic or hard copy) list of BES Elements for which DDR data is required, developed in accordance with Requirement R5, Part

5.1 and Part 5.2; and re-evaluated in accordance with Part 5.4. The Reliability Coordinator has dated evidence (electronic or hard copy) that each Transmission Owner or Generator Owner has been notified in accordance with Requirement 5, Part 5.3. Evidence may include, but is not limited to: letters, emails, electronic files, or hard copy records demonstrating transmittal of information.

R6. Each Transmission Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

6.1. One phase-to-neutral or positive sequence voltage.

6.2. The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R6, Part 6.1, or the positive sequence current.

6.3. Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required.

6.4. Frequency of any one of the voltage(s) in Requirement R6, Part 6.1.

M6. The Transmission Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R6. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R7. Each Generator Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

7.1. One phase-to-neutral, phase-to-phase, or positive sequence voltage at either the generator step-up transformer (GSU) high-side or low-side voltage level.

7.2. The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R7, Part 7.1, phase current(s) for any phase-to-phase voltages, or positive sequence current.

7.3. Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required.

7.4. Frequency of at least one of the voltages in Requirement R7, Part 7.1.

M7. The Generator Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R7. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R8. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have continuous data recording and storage. If the equipment was installed prior to the effective date of this standard and is not capable of continuous recording, triggered records must meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

8.1. Triggered record lengths of at least three minutes.

8.2. At least one of the following three triggers:

- Off nominal frequency trigger set at:

	Low	High
○ Eastern Interconnection	<59.75 Hz	>61.0 Hz
○ Western Interconnection	<59.55 Hz	>61.0 Hz
○ ERCOT Interconnection	<59.35 Hz	>61.0 Hz
○ Hydro-Quebec Interconnection	<58.55 Hz	>61.5 Hz

- Rate of change of frequency trigger set at:

○ Eastern Interconnection	< -0.03125 Hz/sec	>0.125 Hz/sec
○ Western Interconnection	< -0.05625 Hz/sec	>0.125 Hz/sec
○ ERCOT Interconnection	< -0.08125 Hz/sec	>0.125 Hz/sec
○ Hydro-Quebec Interconnection	< -0.18125 Hz/sec	>0.1875 Hz/sec

- Undervoltage trigger set no lower than 85 percent of normal operating voltage for a duration of 5 seconds.

M8. Each Transmission Owner and Generator Owner has dated evidence (electronic or hard copy) of data recordings and storage in accordance with Requirement R8. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings.

R9. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have DDR data that meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

9.1. Input sampling rate of at least 960 samples per second.

9.2. Output recording rate of electrical quantities of at least 30 times per second.

M9. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that DDR data meets Requirement R9. Evidence may include, but is not limited to: (1) documents describing the device specification, device configuration, or settings (R9, Part 9.1; R9, Part 9.2); or (2) actual data recordings (R9, Part 9.2).

R10. Each Transmission Owner and Generator Owner shall time synchronize all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES

Elements identified in Requirement R5 to meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

10.1. Synchronization to Coordinated Universal Time (UTC) with or without a local time offset.

10.2. Synchronized device clock accuracy within ± 2 milliseconds of UTC.

M10. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of time synchronization described in Requirement R10. Evidence may include, but is not limited to: (1) documents describing the device specification, configuration, or setting; (2) time synchronization indication or status; or 3) station drawings.

R11. Each Transmission Owner and Generator Owner shall provide, upon request, all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to the Reliability Coordinator, Regional Entity, or NERC in accordance with the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

11.1. Data will be retrievable for the period of 10-calendar days, inclusive of the day the data was recorded.

11.2. Data subject to Part 11.1 will be provided within 30-calendar days of a request unless an extension is granted by the requestor.

11.3. SER data will be provided in ASCII Comma Separated Value (CSV) format following Attachment 2.

11.4. FR and DDR data will be provided in electronic files that are formatted in conformance with C37.111, (IEEE Standard ~~for~~ Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later.

11.5. Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.

M11. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that data was submitted upon request in accordance with Requirement R11. Evidence may include, but is not limited to: (1) dated transmittals to the requesting entity with formatted records; (2) documents describing data storage capability, device specification, configuration or settings; or (3) actual data recordings.

R12. Each Transmission Owner and Generator Owner shall, within 90-calendar days of the discovery of a failure of the recording capability for the SER, FR or DDR data, either: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

- Restore the recording capability, or
- Submit a Corrective Action Plan (CAP) to the Regional Entity and implement it.

M12. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R12. Evidence may include, but is not limited to: (1)

dated reports of discovery of a failure, (2) documentation noting the date the data recording was restored, (3) SCADA records, or (4) dated CAP transmittals to the Regional Entity and evidence that it implemented the CAP.

R13. Each Transmission Owner and Generator Owner shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

13.1. Within three (3) calendar years of completing a re-evaluation or receiving notification under Requirement R1, Part 1.3, have SER or FR data as applicable for BES Elements directly connected to the identified BES buses.

13.2. Within three (3) calendar years of receiving notification under Requirement R5, Part 5.4, have DDR data for BES Elements identified during the re-evaluation.

M13. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R13. Evidence may include, but is not limited to: letters, emails, drawings, or settings files.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

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

1.2. Evidence Retention:

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

The Transmission Owner, Generator Owner, and Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner shall retain evidence of Requirement R1, Measure M1 for five calendar years.

The Reliability Coordinator shall retain evidence of Requirement R5, Measure M5 for five calendar years.

The Transmission Owner shall retain evidence of Requirement R6, Measure M6 for three calendar years.

The Generator Owner shall retain evidence of Requirement R7, Measure M7 for three calendar years.

The Transmission Owner and Generator Owner shall retain evidence of requested data provided as per Requirements R2, R3, R4, R8, R9, R10, R11, and R12, Measures M2, M3, M4, M8, M9, M10, M11, and M12 for three calendar years.

~~The Reliability Coordinator shall retain evidence of Requirement R5, Measure M5 for five calendar years.~~

The Transmission Owner and Generator Owner as applicable shall retain evidence of Requirement R13, Measure 13 for five calendar years.

If a Transmission Owner, Generator Owner, or Reliability Coordinator is found non- compliant, it shall keep information related to the non-compliance until mitigation is completed and approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program:

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1.	Long-term Planning	Lower	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 80 percent but less than 100 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by 30- calendar days or less. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other owners that their BES Elements require SER or FR data by 10-calendar days or less.	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 70 percent but less than 80 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 30-calendar days and less than or equal to 60-calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other owners that their BES Elements require SER or FR data by greater than 10-calendar days but less than or equal to 20-calendar days.	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 60 percent but less than 70 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 60-calendar days and less than or equal to 90-calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other owners that their BES Elements require SER or FR data by greater than 20-calendar days but less than or equal to 30-calendar days.	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for less than or equal to 60 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 90-calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying one or more other owners that their BES Elements require SER or FR data by greater than 30-calendar days.

R2.	Long-term Planning	Lower	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 80 percent but less than 100 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 70 percent but less than or equal to 80 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 60 percent but less than or equal to 70 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 for less than or equal to 60 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.
R3.	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 80 percent but less than 100 percent of the total set of required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 70 percent but less than or equal to 80 percent of the total set of required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 60 percent but less than or equal to 70 percent of the total set of required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers less than or equal to 60 percent of the total set of required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.
R4.	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data that meets more than 80 percent but less than 100 percent of the total recording	The Transmission Owner or Generator Owner had FR data that meets more than 70 percent but less than or equal to 80 percent of the total	The Transmission Owner or Generator Owner had FR data that meets more than 60 percent but less than or equal to 70 percent of the	The Transmission Owner or Generator Owner had FR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R4.

			properties as specified in Requirement R4.	recording properties as specified in Requirement R4.	total recording properties as specified in Requirement R4.	
R5.	Long-term Planning	Lower	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 80 percent but less than 100 percent of the required BES Elements included in Part 5.1. OR The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by 30-calendar days or less. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by 10-calendar days or less.	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 70 percent but less than or equal to 80 percent of the required BES Elements included in Part 5.1. OR The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 30-calendar days and less than or equal to 60 -calendar days. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by greater than 10-calendar days but less than or equal to 20-calendar days.	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 60 percent but less than or equal to 70 percent of the required BES Elements included in Part 5.1. OR The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 60-calendar days and less than or equal to 90-calendar days. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by greater than 20-calendar days but less than or equal to 30-calendar days.	The Reliability Coordinator identified the BES Elements for which DDR data is required as directed by Requirement R5 for less than or equal to 60 percent of the required BES Elements included in Part 5.1. OR The Reliability Coordinator identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 90-calendar days. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying one or more owners that their BES Elements require DDR data by greater than 30-calendar days. OR

						The Reliability Coordinator failed to ensure a minimum DDR coverage per Part 5.2.
R6.	Long-term Planning	Lower	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 that covered more than 80 percent but less than 100 percent of the total required electrical quantities for all applicable BES Elements.	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 70 percent but less than or equal to 80 percent of the total required electrical quantities for all applicable BES Elements.	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 60 percent but less than or equal to 70 percent of the total required electrical quantities for all applicable BES Elements.	The Transmission Owner failed to have DDR data as directed by Requirement R6, Parts 6.1 through 6.4.
R7.	Long-term Planning	Lower	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 that covers more than 80 percent but less than 100 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 70 percent but less than or equal to 80 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 60 percent but less than or equal to 70 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner failed to have DDR data as directed by Requirement R7, Parts 7.1 through 7.4.
R8.	Long-term Planning	Lower	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 80 percent but less than 100 percent of the BES Elements they own as	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 70 percent but less than or equal to 80 percent of the BES Elements they own as	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 60 percent but less than or equal to 70 percent of the BES Elements	The Transmission Owner or Generator Owner failed to have continuous or non-continuous DDR data, as directed in Requirement R8, for the BES Elements they own as determined in Requirement R5.

			determined in Requirement R5.	determined in Requirement R5.	they own as determined in Requirement R5.	
R9.	Long-term Planning	Lower	The Transmission Owner or Generator Owner had DDR data that meets more than 80 percent but less than 100 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 70 percent but less than or equal to 80 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 60 percent but less than or equal to 70 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R9.
R10.	Long-term Planning	Lower	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 90 percent but less than 100 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 80 percent but less than or equal to 90 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 70 percent but less than or equal to 80 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner failed to have time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for less than or equal to 70 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.
R11.	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.~~1~~2 provided the requested data more than 30-calendar days but less than 40-calendar days after the request unless an extension	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.~~1~~2 provided the requested data more than 40-calendar days but less than or equal to 50-calendar days after the request unless an extension	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.~~1~~2 provided the requested data more than 50-calendar days but less than or equal to 60-calendar days after the request unless an extension	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.~~1~~2 failed to provide the requested data more than 60-calendar days after the request unless an extension

			was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 90 percent but less than 100 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 90 percent of the data but less than 100 percent of the data in the proper data format.	was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 80 percent but less than or equal to 90 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 80 percent of the data but less than or equal to 90 percent of the data in the proper data format.	was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 70 percent but less than or equal to 80 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 70 percent of the data but less than or equal to 80 percent of the data in the proper data format.	was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 failed to provide less than or equal to 70 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided less than or equal to 70 percent of the data in the proper data format.
R12.	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 90-calendar days but less than or equal to 100-	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 100-calendar days but less than or equal to 110-calendar	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 110-calendar days but less than or equal to 120-	The Transmission Owner or Generator Owner as directed by Requirement R12 failed to report a failure and provide a Corrective Action Plan to the Regional Entity more than 120-calendar days after discovery of the failure. OR

			calendar days after discovery of the failure.	days after discovery of the failure.	calendar days after discovery of the failure. OR The Transmission Owner or Generator Owner as directed by Requirement R12 submitted a CAP to the Regional Entity but failed to implement it.	Transmission Owner or Generator Owner as directed by Requirement R12 failed to restore the recording capability and failed to submit a CAP to the Regional Entity.
R13.	Long-term Planning	Lower		The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by less than or equal to 6 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4 and was late by less than or equal to 6 months.	The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by greater than 6 months but less than or equal to 12 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4 and was late by greater than 6 months but less	The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by greater than 12 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4 and was late by greater than 12 months.

					than or equal to 12 months.	

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

~~None~~NERC Reliability Standard PRC-002-4: Implementation Plan.

G. References

IEEE C37.111: Common format for transient data exchange (COMTRADE) for power Systems.

IEEE C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME). Standard published 11/09/2011 by IEEE.

NERC Reliability Standard PRC-002-4: Technical Rationale.

NPCC SP6 Report Synchronized Event Data Reporting, revised March 31, 2005

U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations (2004).

U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout in the United States and Canada (Nov. 2003).

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
1	August 2, 2006	Adopted by NERC Board of Trustees	Revised
2	November 13, 2014	Adopted by NERC Board of Trustees	Revised under Project 2007-11 and merged with PRC-018-1.
2	September 24, 2015	FERC approved PRC-005-4. Docket No. RM15-4-000; Order No. 814	
3	May 13, 2021	Adopted by NERC Board of Trustees	Revised
4	TBD	TBD	Revised under Project 2021-04

Attachment 1

Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data

(Requirement R1)

To identify monitored BES buses for sequence of events recording (SER) and Fault recording (FR) data required by Requirement 1, each Transmission Owner shall follow sequentially, unless otherwise noted, the steps listed below:

Step 1. Determine a complete list of BES buses that it owns.

For the purposes of this standard, a single BES bus includes physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid. These buses may be modeled or represented by a single node in fault studies. For example, ring bus or breaker-and-a-half bus configurations are considered to be a single bus.

Step 2. Reduce the list to those BES buses that have a maximum available calculated three phase short circuit MVA of 1,500 MVA or greater. If there are no buses on the resulting list, proceed to Step 7.

Step 3. Determine the 11 BES buses on the list with the highest maximum available calculated three phase short circuit MVA level. If the list has 11 or fewer buses, proceed to Step 7.

Step 4. Calculate the median MVA level of the 11 BES buses determined in Step 3.

Step 5. Multiply the median MVA level determined in Step 4 by 20 percent.

Step 6. Reduce the BES buses on the list to only those that have a maximum available calculated three phase short circuit MVA higher than the greater of:

- 1,500 MVA or
- 20 percent of median MVA level determined in Step 5.

Step 7. If there are no BES buses on the list: the procedure is complete and no FR and SER data will be required. Proceed to Step 9.

If the list has 1 or more but less than or equal to 11 BES buses: FR and SER data is required at the BES bus with the highest maximum available calculated three phase short circuit MVA as determined in Step 3. ~~Proceed to Step 9.~~ During re-evaluation per Requirement R1, Part 1.3, if the three phase short circuit MVA of the newly identified BES bus is within 15% of the three phase short circuit MVA of the currently applicable BES bus with SER and FR data then it is not necessary to change the applicable BES bus. Proceed to Step 9.

If the list has more than 11 BES buses: SER and FR data is required on at least the 10 percent of the BES buses determined in Step 6 with the highest maximum available calculated three phase short circuit MVA. Proceed to Step 8.

Step 8. SER and FR data is required at additional BES buses on the list determined in Step 6. The aggregate of the number of BES buses determined in Step 7 and this Step will be at least 20 percent of the BES buses determined in Step 6.

The additional BES buses are selected, at the Transmission Owner's discretion, to provide maximum wide-area coverage for SER and FR data. The following BES bus locations are recommended:

- Electrically distant buses or electrically distant from other DME devices.
- Voltage sensitive areas.
- Cohesive load and generation zones.
- BES buses with a relatively high number of incident Transmission circuits.
- BES buses with reactive power devices.
- Major Facilities interconnecting outside the Transmission Owner's area.

Step 9. The list of monitored BES buses for SER and FR data for Requirement R1 is the aggregate of the BES buses determined in Steps 7 and 8.

Attachment 2

Sequence of Events Recording (SER) Data Format

(Requirement R11, Part 11.3)

Date, Time, Local Time Code, Substation, Device, State[2]

08/27/13, 23:58:57.110, -5, Sub 1, Breaker 1, Close

08/27/13, 23:58:57.082, -5, Sub 2, Breaker 2, Close

08/27/13, 23:58:47.217, -5, Sub 1, Breaker 1, Open

08/27/13, 23:58:47.214, -5, Sub 2, Breaker 2, Open

[2] "OPEN" and "CLOSE" are used as examples. Other terminology such as TRIP, TRIP TO LOCKOUT, RECLOSE, etc. is also acceptable.

High Level Requirement Overview

<table>
<tr><th>Requirement</th><th>Entity</th><th>Identify BES Buses</th><th>Notification</th><th>SER</th><th>FR</th><th>5 Year Re-evaluation</th></tr>
<tr><td>R1</td><td>TO</td><td>X</td><td>X</td><td>X</td><td>X</td><td>X</td></tr>
<tr><td>R2</td><td>TO | GO</td><td></td><td></td><td>X</td><td></td><td></td></tr>
<tr><td>R3</td><td>TO | GO</td><td></td><td></td><td></td><td>X</td><td></td></tr>
<tr><td>R4</td><td>TO | GO</td><td></td><td></td><td></td><td>X</td><td></td></tr>
<tr><th>Requirement</th><th>Entity</th><th>Identify BES Elements</th><th>Notification</th><th>DDR</th><th colspan="2">5 Year Re-evaluation</th></tr>
<tr><td>R5</td><td>RE (PC | RC)</td><td>X</td><td>X</td><td>X</td><td colspan="2">X</td></tr>
<tr><td>R6</td><td>TO</td><td></td><td></td><td>X</td><td colspan="2"></td></tr>
<tr><td>R7</td><td>GO</td><td></td><td></td><td>X</td><td colspan="2"></td></tr>
<tr><td>R8</td><td>TO | GO</td><td></td><td></td><td>X</td><td colspan="2"></td></tr>
<tr><td>R9</td><td>TO | GO</td><td></td><td></td><td>X</td><td colspan="2"></td></tr>
</table>

<table>
<tr><th>Requirement</th><th>Entity</th><th>Time Synchronization</th><th>Provide SER, FR, DDR Data</th><th>SER, FR, DDR Availability</th></tr>
<tr><td>R10</td><td>TO | GO</td><td>X</td><td></td><td></td></tr>
<tr><td>R11</td><td>TO | GO</td><td></td><td>X</td><td></td></tr>
<tr><td>R12</td><td>TO | GO</td><td></td><td></td><td>X</td></tr>
</table>

<table>
<tr><th>Requirement</th><th>Entity</th><th>Implementation</th></tr>
<tr><td>R13</td><td>TO | GO</td><td>X</td></tr>
</table>

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	01/20/2021
SAR posted for comment	06/29/2021 – 07/28/2021

Anticipated Actions	Date
45-day formal or informal comment period with ballot	10/03/2022 – 11/17/2022
~~XX~~45-day formal or informal comment period with additional ballot	12/05/2022 – 01/18/2023
~~XX~~10-day final ballot	02/13/2023 – 02/22/2023
Board adoption	03/22/2023

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):

N/A.

A. Introduction

1. **Title:** **Transmission Relay Loadability**
2. **Number:** PRC-023-~~5~~6
3. **Purpose:** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.
4. **Applicability:**

4.1. Functional Entity:

4.1.1 Transmission Owner with load-responsive phase protection systems as described in PRC-023-~~5~~6 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

4.1.2 Generator Owner with load-responsive phase protection systems as described in PRC-023-~~5~~6 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

4.1.3 Distribution Provider with load-responsive phase protection systems as described in PRC-023-~~5~~6 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*, provided those circuits have bi- directional flow capabilities.

4.1.4 Planning Coordinator

4.2. Circuits:

4.2.1 Circuits Subject to Requirements R1 – R5:

4.2.1.1 Transmission lines operated at 200 kV and above, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with

Requirement R6.

4.2.1.4 Transformers with low voltage terminals connected at 200 kV and above.

4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

4.2.1.6 Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

4.2.2 Circuits Subject to Requirement R6:

4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

4.2.2.2 Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

5. **Effective Dates:** See Implementation Plan. See Implementation Plan. As provided therein, each Generator Owner, Transmission Owner, and Distribution Provider that owns circuits that become applicable to this standard pursuant to Requirement R6 shall become compliant with R1 through R5 on the later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date.

B. Requirements and Measures

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning].*

Criteria:

1. Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).
2. Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating[1] of a circuit (expressed in amperes).
3. Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:
   - An infinite source (zero source impedance) with a 1.00 per unit bus voltage at

each end of the line.

- An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.

4. Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:

   - 115% of the highest emergency rating of the series capacitor.
   - 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with Requirement R1, criterion 3, using the full line inductive reactance.

5. Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).

[1] When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

6. ~~Not used.~~Reserved
7. Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.
8. Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.
9. Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.
10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that the relays do not operate at or below the greater of:
    - 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
    - 115% of the highest operator established emergency transformer rating.

    10.1 Set load-responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability[2].
11. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, criterion 10 set the relays according to one of the following:
    - Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater, for at least 15 minutes to provide time for the operator to take controlled action to relieve the overload.
    - Install supervision for the relays using either a top oil or simulated winding hot spot temperature element set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature[3].
12. When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to

a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:

a. Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.

b. Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.

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[2] As illustrated by the "dotted line" in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration,* Clause 4.4, Figure 4.

[3] IEEE standard C57.91, Tables 7 and 8, specify that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and Annex A cautions that bubble formation may occur above 140 degrees C.

c. Include a relay setting component of 87% of the current calculated in Requirement R1, criterion 12 in the Facility Rating determination for the circuit.

13. Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)

~~**criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)**~~

R2. Reserved. ~~Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*~~

M2. Reserved.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion 7, 8, 9, 12, or 13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*

M3. Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

M4. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the ERO to compile a list of all circuits that have protective relay settings that limit circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

M5. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)

R6. Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in PRC-023-~~5~~6, Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

6.1 Maintain a list of circuits subject to PRC-023-~~5~~6 per application of Attachment B, including identification of the first calendar year in which any criterion in PRC-023-~~5~~6, Attachment B applies.

6.2 Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

M6. Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within PRC-023-6, Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe. (R6)

~~6.2~~

~~by: (i),; (ii)the ,~~

~~C. Measures~~

~~**M1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per~~

~~criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)~~

~~M2.~~ **M2. Reserved.** ~~Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its out-of-step blocking elements is set to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. (R2)~~

~~M3. Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)~~

~~M4. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)~~

~~M5. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)~~

~~M6. Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within PRC-023-5~~6, ~~Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe. (R6)~~

~~D.~~C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Data Retention

The Transmission Owner, Generator Owner, Distribution Provider and Planning Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5 for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in Requirement R6. The Planning Coordinator shall retain the most recent list of circuits in its Planning Coordinator area for which applicable entities must comply with the standard, as determined per Requirement R6.

If a Transmission Owner, Generator Owner, Distribution Provider, or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit record and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information

None.

Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. OR The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.
R2	N/A	N/A	N/A	**Reserved.**~~The responsible entity failed to ensure that its out-of-step blocking elements allowed tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.~~

R3	N/A	N/A	N/A	The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the Facility Rating of the circuit.

Requirement	Lower	Moderate	High	Severe
				OR The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.
R4	N/A	N/A	N/A	The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports.
R5	N/A	N/A	N/A	The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once each calendar year, with no more than 15 months between reports.

R6	N/A	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24	The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

Requirement	Lower	Moderate	High	Severe
		than 15 months and less than 24 months lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first applies. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met	months or more lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)	OR The Planning Coordinator used the criteria established within Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process described in Requirement R6. (part 6.1) OR The Planning Coordinator used the criteria established within

		6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after		Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met

Requirement	Lower	Moderate	High	Severe
		the list was established or updated. (part 6.2)		6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2) OR The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

~~E.~~D. Regional ~~Differences~~Variances

None.

~~F.~~E. ~~Supplemental Technical Reference Document~~Associated Documents

1. The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies.

   "Determination and Application of Practical Relaying Loadability Ratings," Version 1.0, June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: http://www.nerc.com/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Fina l_2008July3.pdf

   NERC Reliability Standard PRC-023-6 Implementation Plan.

   NERC Reliability Standard PRC-023-6 Technical Rationale.

Version History

Version	Date	Action	Change Tracking
1	February 12, 2008	Approved by Board of Trustees	New
1	March 19, 2008	Corrected typo in last sentence of Severe VSL for Requirement 3 — "then" should be "than."	Errata
1	March 18, 2010	Approved by FERC	
1	Filed for approval April 19, 2010	Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733	Revision
2	March 10, 2011 approved by Board of Trustees	Revised to address initial set of directives from Order 733	Revision (Project 2010-13)
2	March 15, 2012	FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)	

3	November 7, 2013	Adopted by NERC Board of Trustees	Supplemental SAR to Clarify applicability for consistency with PRC-025-1 and other minor corrections.

Version	Date	Action	Change Tracking
4	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
4	November 19, 2015	FERC Order issued approving PRC-023-4. Docket No. RM15-13-000.	
5	May 13, 2021	Adopted by the NERC Board of Trustees	
5	DATE	Add FERC approval history	
6		Revised by Project….	Retired Requirement R2, remove Attachment A, Section/Part 2.3

PRC-023-~~5~~6 — Attachment A

1. This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:

   1.1. Phase distance.

   1.2. Out-of-step tripping.

   1.3. Switch-on-to-fault.

   1.4. Overcurrent relays.

   1.5. Communications aided protection schemes including but not limited to:

      1.5.1 Permissive overreach transfer trip (POTT).

      1.5.2 Permissive under-reach transfer trip (PUTT).

      1.5.3 Directional comparison blocking (DCB).

      1.5.4 Directional comparison unblocking (DCUB).

   1.6. Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current- based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.

2. The following protection systems are excluded from requirements of this standard:

   2.1. Relay elements that are only enabled when other relays or associated systems fail. For example:

   - Overcurrent elements that are only enabled during loss of potential conditions.
   - Elements that are only enabled during a loss of communications except as noted in section 1.6.

   2.2. Protection systems intended for the detection of ground fault conditions.

   2.3. Reserved.~~Protection systems intended for protection during stable power swings.~~

   2.4. ~~Not used.~~Reserved

   2.5. Relay elements used only for Remedial Action Schemes applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017 or their successors.

   2.6. Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.

   2.7. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.

   2.8. Relay elements associated with dc lines.

   2.9. Relay elements associated with dc converter transformers.

PRC-023-~~5~~6 —
Attachment B

Circuits to Evaluate

- Transmission lines operated at 100 kV to 200kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the Bulk Electric System.

Criteria

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

B1. The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.

B2. The circuit is selected by the Planning Coordinator or Transmission Planner based on Planning Assessments of the Near-Term Transmission Planning Horizon that identify instances of instability, Cascading, or uncontrolled separation, that adversely impact the reliability of the Bulk Electric System for planning events.

B3. The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.

B4. The circuit is identified through the following sequence of power flow analyses[4] performed by the Planning Coordinator for the one-to-five-year planning horizon:

a. Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).

b. For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.

4 Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

c. When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.

d. The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.

   i. If the Facility Rating is based on a loading duration of up to and including four hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.

   ii. If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.

   iii. If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.

e. Radially operated circuits serving only load are excluded.

B5. The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.

B6. The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

This is the first draft of the proposed standard.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 20, 2021
SAR posted for comment	July 08 – August 06, 2021
SAR posted for comment	January 11 – February 09, 2022
45-day formal comment period with ballot	October 25 – December 09, 2022

Anticipated Actions	Date
45-day formal comment period with additional ballot	February 22 – April 03, 2023
10-day final ballot	April 17 – April 27, 2023
Board adoption	May 2023

A. Introduction

1. **Title:** Reliability Coordinator Data and Information Specification and Collection
2. **Number:** IRO-010-5~~4~~
3. **Purpose:** To prevent instability, uncontrolled separation, or Cascading outages that adversely impact reliability, by ensuring the Reliability Coordinator has the data and information it needs to plan, Monitor and assess the operation of its Reliability Coordinator Area.
4. **Applicability**

   4.1. Reliability Coordinator

   4.2. Balancing Authority

   4.3. Generator Owner

   4.4. Generator Operator

   4.5. Transmission Operator

   4.6. Transmission Owner

   4.7. Distribution Provider

5. **Effective Date:** See Implementation Plan for Project 2019-06.

B. Requirements

R1. The Reliability Coordinator shall maintain a documented specification for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The ~~data~~ specification shall include but not be limited to: *(Violation Risk Factor: Low) (Time Horizon: Operations Planning)*

1.1. A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessment, including non-BES data and information, external network data and information, and identification of the applicable entities responsible for responding to the specification as deemed necessary by the Reliability Coordinator.

1.2. Provisions for notification of current Protection System and Remedial Action Scheme (RAS) status or degradation that impacts System reliability.

1.3. Provisions for notification of BES generating unit(s) during local forecasted cold weather to include:

1.3.1 Operating limitations based on:

1.3.1.1. capability and availability;

1.3.1.2. fuel supply and inventory concerns;

1.3.1.3. fuel switching capabilities; and

1.3.1.4. environmental constraints

1.3.2. Generating unit(s) minimum:

1.3.2.1. design temperature; or

1.3.2.2. historical operating temperature; or

1.3.2.3. current cold weather performance temperature determined by an engineering analysis.

1.4. Provisions for the identification of any data and information where the responsible respondent identified in Part 1.1 will utilize an applicable entity as an intermediary to pass through the data and information unaltered from the entities that originated the data and information.

1.5. Protocols for the responsible respondent identified in Part 1.1 to provide data and information that includes, but is not limited to:

1.5.1 Specific deadlines or periodicity in which data and information is to be provided;

1.5.2 Performance criteria for the availability and accuracy of data and information, as applicable;

1.5.3 Provisions to update or correct data and information, as applicable or necessary.

1.6. Identification of the mutually agreed upon format.

1.7. Identification of the mutually agreed upon process for resolving conflicts between the Reliability Coordinator, the responsible respondent identified in Part 1.1 that has the required data and information, and if necessary, the intermediary.

1.8. Identification of the mutually agreed upon security protocol or method for securely transferring data and information.

~~The deadline by which the respondent is to provide the indicated data.~~

M1. The Reliability Coordinator shall make available its dated, current, in force documented specification for data and information.

R2. The Reliability Coordinator shall distribute its data and information specification to entities that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. *(Violation Risk Factor: Low) (Time Horizon: Operations Planning)*

M2. The Reliability Coordinator shall make available evidence that it has distributed its ~~data~~ specification to entities that have data and information required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and

Real-time Assessments. This evidence could include but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

R3. Each Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Transmission Operator, Transmission Owner, and Distribution Provider receiving a ~~data~~ specification in Requirement R2 shall satisfy the ~~obligations of the~~ documented specifications using the criteria established in Requirement Parts 1.5 through 1.8: *(Violation Risk Factor: Medium) (Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations)*

~~**3.1.** A mutually agreeable format~~

~~**3.2.** A mutually agreeable process for resolving data conflicts~~

~~**3.3.** A mutually agreeable security protocol~~

M3. The Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Reliability Coordinator, Transmission Operator, Transmission Owner, and Distribution Provider receiving a ~~data~~specification in Requirement R2 shall make available evidence that it satisfied the obligations of the documented specification using the specified criteria. Such evidence could include but is not limited to electronic or hard copies of data transmittals or attestations of receiving entities.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with the 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 Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Transmission Operator, Transmission Owner, and Distribution Provider shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Reliability Coordinator shall retain its dated, current, in force documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments for Requirement R1, Measure M1 as well as any documents in force since the last compliance audit.

The Reliability Coordinator shall keep evidence for three calendar years that it has distributed its data specification to entities that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments for Requirement R2, Measure M2.

Each Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification shall retain evidence for the most recent 90-calendar days that it has satisfied the obligations of the documented specifications in accordance with Requirement R3 and Measurement M3.

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	Moderate	High	Severe
R1	Operations Planning	Low	The Reliability Coordinator did not include two or fewer of the parts (Part 1.1 through Part 1.8~~5~~) of the documented specification for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not include three to four of the parts (Part 1.1 through Part 1.8~~5~~) of the documented specification for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not include five to seven ~~our~~ of the parts (Part 1.1 through Part 1.8~~5~~) of the documented specification for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not include any of the parts (Part 1.1 through Part 1.8~~5~~) of the documented specification for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. OR, The Reliability Coordinator did not have a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time

						monitoring, and Real-time Assessments
For the Requirement R2 VSLs only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.						
R2	Operations Planning	Low	The Reliability Coordinator did not distribute its ~~data~~ specification as developed in Requirement R1 to one entity, or 5% or less of the entities, whichever is greater, that have data and information required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not distribute its ~~data~~ specification as developed in Requirement R1 to two entities, or more than 5% and less than or equal to 10% of the reliability entities, whichever is greater, that have data and information required by the Reliability Coordinator's Operational Planning Analyses, and Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not distribute its ~~data~~ specification as developed in Requirement R1 to three entities, or more than 10% and less than or equal to 15% of the reliability entities, whichever is greater, that have data and information required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not distribute its ~~data~~ specification as developed in Requirement R1 to four or more entities, or more than 15% of the entities, whichever is greater, that have data and information required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

R3	Operations Planning, Same-Day Operations, Real-time Operations	Medium	The responsible entity receiving a ~~data~~specification in Requirement R2 satisfied the ~~obligations of the~~ documented specifications ~~for data~~but failed to ~~follow~~ use one of the criteria ~~shown~~in Requirement R1 Parts 1~~3~~.5~~1~~ – 1~~3~~.8~~3~~.	The responsible entity receiving a ~~data~~specification in Requirement R2 satisfied the ~~obligations of the~~ documented specifications ~~for data~~but failed to use~~follow~~ two of the criteria ~~shown~~in Requirement R1 Parts 1~~3~~.5~~1~~ – 1~~3~~.8~~3~~.	The responsible entity receiving a ~~data~~specification in Requirement R2 satisfied the ~~obligations of the~~ documented specifications ~~for data~~but failed to use~~follow any~~ three or more of the criteria ~~shown~~ in Requirement R1 Parts 1~~3~~.5~~1~~ – 1~~3~~.8~~3~~.	The responsible entity receiving a ~~data~~specification in Requirement R2 did not satisfy the ~~obligations of the~~ documented specifications ~~for data~~.

D. Regional Variances

None

E. Interpretations

None

F. Associated Documents

None

Version History

Version	Date	Action	Change Tracking
1	October 17, 2008	Adopted by Board of Trustees	New
1a	August 5, 2009	Added Appendix 1: Interpretation of R1.2 and R3 as approved by Board of Trustees	Addition
1a	March 17, 2011	Order issued by FERC approving IRO-010-1a (approval effective 5/23/11)	
1a	November 19, 2013	Updated VRFs based on June 24, 2013 approval	
2	April 2014	Revisions pursuant to Project 2014-03	
2	November 13, 2014	Adopted by NERC Board of Trustees	Revisions under Project 2014-03
2	November 19, 2015	FERC approved IRO-010-2. Docket No. RM15-16-000	
3	February 6, 2020	Adopted by NERC Board of Trustees	Revisions under Project 2017-07
4	TBD	Adopted by NERC Board of Trustees	Revisions under Project 2019-06 Cold Weather
3	October 30, 2020	FERC approved IRO-010-2. Docket No. RD20-4-000	
4	June 11, 2021	Adopted by NERC Board of Trustees	Revisions under Project 2019-06
4	August 24,2021	FERC approved IRO-010-4 Docket No. RD21-5-000	
4	August 24, 2021	April 1, 2023	Effective Date
		TBD	TBD

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

This is the first draft of the proposed standard.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 20, 2021
SAR posted for comment	July 8 – August 6, 2021
SAR posted for comment	January 11 – February 9, 2022
45-day formal comment period with ballot	October 25 – December 9, 2022

Anticipated Actions	Date
45-day formal comment period with additional ballot	February 22 – April 3, 2023
10-day final ballot	April 17 – April 27, 2023
Board adoption	May 2023

A. Introduction

1. **Title:** ~~**Operational Reliability**~~**Transmission Operator and Balancing Authority Data and Information Specification and Collection**

2. **Number: TOP-003-~~5~~6**

3. **Purpose:** To ensure that the Transmission Operator and Balancing Authority have the data and information it need~~sed~~ to plan, monitor, and assess the ~~fulfill their~~ operation~~al~~ of its Transmission Operator Area or Balancing Authority Area ~~and planning responsibilities~~.

4. **Applicability:**

   4.1. Transmission Operator

   4.2. Balancing Authority

   4.3. Generator Owner

   4.4. Generator Operator

   4.5. Transmission Owner

   4.6. Distribution Provider

5. **Effective Date:** See Implementation Plan for Project 2019-06.

B. Requirements and Measures

R1. Each Transmission Operator shall maintain a documented specification for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The ~~data~~ specification shall include, but not be limited to: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

1.1. A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and information, ~~and~~ external network data and information, and identification of the applicable entities responsible for responding to the specification as deemed necessary by the Transmission Operator.

1.2. Provisions for notification of current Protection System and Remedial Action Scheme (RAS) status or degradation that impacts System reliability.

1.3. Provisions for notification of BES generating unit(s) during local forecasted cold weather to include:

1.3.1. Operating limitations based on:

1.3.1.1. capability and availability;

1.3.1.2. fuel supply and inventory concerns;

1.3.1.3. fuel switching capabilities; and

1.3.1.4. environmental constraints

1.3.2. Generating unit(s) minimum:

1.3.2.1. design temperature; or

1.3.2.2. historical operating temperature; or

1.3.2.3. current cold weather performance temperature determined by an engineering analysis.

1.4. ~~A p~~Provision~~s~~~~eriodicity~~ for the identification of ~~providing~~ any data and information where the responsible respondent identified in Part 1.1 will utilize an applicable entity as an intermediary to pass through the data and information unaltered from the entities that originated the data and information.

1.5. ~~The deadline by which the respondent is to~~Protocols for the responsible respondent identified in Part 1.1 to provide the ~~indicated~~ data and information that includes, but is not limited to~~.~~:

1.5.1. Specific deadlines or periodicity in which data and information is to be provided;

1.5.2. Performance criteria for the availability and accuracy of data and information, as applicable;

1.5.3. Provisions to update or correct data and information, as applicable or necessary.

1.6. Identification of the mutually agreed upon format.

1.7. Identification of the mutually agreed upon process for resolving conflicts between the Transmission Operator, the responsible respondent identified in Part 1.1 that has the required data and information, and where applicable, the intermediary.

~~**1.5.**~~ Identification of the mutually agreed upon security protocol or method for securely transferring data and information.

1.8.

M1. Each Transmission Operator shall make available its dated, current, in force documented specification for data and information.

R2. Each Balancing Authority shall maintain a documented specification for the data and information necessary for it to perform its analysis functions and Real-time monitoring. The data specification shall include, but not be limited to: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

2.1. A list of data and information needed by the Balancing Authority to support its analysis functions and Real-time monitoring including non-BES data and information, and external network data and information, as deemed necessary by the Balancing Authority. The list shall include, but is not limited to, identification of the applicable entity responsible for responding to the specification.

2.2. Provisions for notification of current Protection System and Remedial Action Scheme status or degradation that impacts System reliability.

2.3. Provisions for notification of BES generating unit(s) status during local forecasted cold weather to include:

2.3.1. Operating limitations based on:

2.3.1.1. capability and availability;

2.3.1.2. fuel supply and inventory concerns;

2.3.1.3. fuel switching capabilities; and

2.3.1.4. environmental constraints.

2.3.2. Generating unit(s) minimum:

2.3.2.1. design temperature; or

2.3.2.2. historical operating temperature; or

2.3.2.3. current cold weather performance temperature determined by an engineering analysis.

2.4. Provisions for the identification of any ~~A periodicity for providing~~ data and information where the responsible respondent identified in Part 2.1 will utilize an applicable entity as an intermediary to pass through the data and information unaltered from the entities that originated the data and information.

2.5. Protocols for the responsible respondent identified in Part 2.1 to provide data and information that includes, but is not limited to:

2.5.1. Specific deadlines or periodicity in which data and information is to be provided;

2.5.2. Performance criteria for the availability and accuracy of data and information, as applicable;

2.5.3. Provisions to update or correct data and information, as applicable or necessary.

2.6. Identification of the mutually agreed upon format.

2.7. Identification of the mutually agreed upon process in resolving conflicts between the Balancing Authority, the responsible respondent identified in Part 2.1 that has the required data and information, and if necessary, the intermediary.

~~2.4.~~2.8. Identification of the mutually agreed upon security protocol or method for securely transferring data and information.

~~The deadline by which the respondent is to provide the indicated data.~~

M2. Each Balancing Authority shall make available its dated, current, in force documented specification for data and information.

R3. Each Transmission Operator shall distribute its data and information specification to entities that have data and information required by the Transmission Operator's Operational Planning Analyses, Real- time monitoring, and Real-time Assessments. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M3. Each Transmission Operator shall make available evidence that it has distributed its ~~data~~ specification to entities that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
Such evidence could include but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

R4. Each Balancing Authority shall distribute its data and information specification to entities that have data and information required by the Balancing Authority's analysis functions and Real-time monitoring. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M4. Each Balancing Authority shall make available evidence that it has distributed its data specification to entities that have data and information required by the Balancing Authority's analysis functions and Real-time monitoring. Such evidence could include but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, or e-mail records.

R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the ~~obligations of the~~ documented specifications using the criteria established in Parts 1.5 through 1.8 or Parts 2.5 through 2.8, as applicable~~:~~. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

~~**5.1.** A mutually agreeable format~~

~~**5.2.** A mutually agreeable process for resolving data conflicts~~

~~**5.3.** A mutually agreeable security protocol~~

M5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Transmission Owner, and Distribution Provider receiving a ~~data~~ specification in Requirement R3 or R4 shall make available evidence that it has satisfied the obligations of the documented specification~~s~~ using the specified criteria. Such evidence could include, but is not limited to, electronic or hard copies of data transmittals or attestations of receiving entities.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable 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.

Each responsible entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

Each Transmission Operator shall retain its dated, current, in force, documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments in accordance with Requirement R1 and Measurement M1 as well as any documents in force since the last compliance audit.

Each Balancing Authority shall retain its dated, current, in force, documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring in accordance with Requirement R2 and Measurement M2 as well as any documents in force since the last compliance audit.

Each Transmission Operator shall retain evidence for three calendar years that it has distributed its data specification to entities that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments in accordance with Requirement R3 and Measurement M3.

Each Balancing Authority shall retain evidence for three calendar years that it has distributed its data specification to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring in accordance with Requirement R4 and Measurement M4.

Each Balancing Authority, Generator Owner, Generator Operator, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall retain evidence for the most recent 90-calendar days that it has satisfied the obligations of the documented specifications in accordance with Requirement R5 and Measurement M5.

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	Operations Planning	Lower	The Transmission Operator did not include two or fewer of the parts (Part 1.1 through Part 1.8~~5~~) of the documented specification for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include three to four of the parts (Part 1.1 through Part 1.8~~5~~) of the documented specification for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include five to seven~~our~~ of the parts (Part 1.1 through Part 1.8~~5~~) of the documented specification for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include any of the parts (Part 1.1 through Part 1.8~~5~~) of the documented specification for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. OR,

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						The Transmission Operator did not have a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R2	Operations Planning	Lower	The Balancing Authority did not include two or fewer of the parts (Part 2.1 through Part 2.8~~5~~) of the documented specification for the data and information necessary for it to perform its analysis functions and Real-time monitoring.	The Balancing Authority did not include three to four of the parts (Part 2.1 through Part 2.~~5~~8) of the documented specification for the data and information necessary for it to perform its analysis functions and Real-time monitoring.	The Balancing Authority did not include five to seven ~~our~~ of the parts (Part 2.1 through Part 2.~~5~~8) of the documented specification for the data and information necessary for it to perform its analysis functions and Real-time monitoring.	The Balancing Authority did not include any of the parts (Part 2.1 through Part 2.~~5~~8) of the documented specification for the data and information necessary for it to perform its analysis functions and Real-time monitoring.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						OR, The Balancing Authority did not have a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring.
For the Requirement R3 and R4 VSLs only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.						
R3	Operations Planning	Lower	The Transmission Operator did not distribute its ~~data~~ specification to one entity, or 5% or less of the entities, whichever is greater, that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not distribute its ~~data~~ specification to two entities, or more than 5% and less than or equal to10% of the reliability entities, whichever is greater, that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time	The Transmission Operator did not distribute its ~~data~~ specification to three entities, or more than 10% and less than or equal to 15% of the reliability entities, whichever is greater, that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time	The Transmission Operator did not distribute its ~~data~~ specification to four or more entities, or more than 15% of the entities that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				monitoring, and Real-time Assessments.	monitoring, and Real-time Assessments.	
R4	Operations Planning	Lower	The Balancing Authority did not distribute its ~~data~~ specification to one entity, or 5% or less of the entities, whichever is greater, that have data and information required by the Balancing Authority's analysis functions and Real-time monitoring.	The Balancing Authority did not distribute its ~~data~~ specification to two entities, or more than 5% and less than or equal to 10% of the entities, whichever is greater, that have data and information required by the Balancing Authority's analysis functions and Real-time monitoring.	The Balancing Authority did not distribute its ~~data~~ specification to three entities, or more than 10% and less than or equal to 15% of the entities, whichever is greater, that have data and information required by the Balancing Authority's analysis functions and Real-time monitoring.	The Balancing Authority did not distribute its ~~data~~ specification to four or more entities, or more than 15% of the entities that have Data and information required by the Balancing Authority's analysis functions and Real-time monitoring.
R5	Operations Planning, Same-Day Operations, Real-time Operations	Medium	The responsible entity receiving a ~~data~~ specification in Requirement R3 or R4 satisfied the ~~obligations in the data~~ specification but failed to use ~~did not meet~~ one of the criteria ~~shown~~ in Requirement R~~5~~1 (Parts ~~5~~1.5~~1~~ – ~~5~~1.8~~3~~) or Requirement R2 (Parts 2.5 – 2.8).	The responsible entity receiving a ~~data~~ specification in Requirement R3 or R4 satisfied the ~~obligations in the data~~ specification but failed to use ~~did not meet~~ two of the criteria ~~shown~~ in Requirement R~~5~~1 (Parts 1~~5~~.5~~1~~ – 1~~5~~.8~~3~~) or Requirement R2 (Parts 2.5 – 2.8).	The responsible entity receiving a ~~data~~ specification in Requirement R3 or R4 satisfied the ~~obligations in the data~~ specification but failed to use ~~did not meet~~ three or more of the criteria ~~shown~~ in Requirement R~~5~~1 (Parts ~~5~~1~~.~~.5~~1~~ – 1~~5~~.8~~3~~) or Requirement R2 (Parts	The responsible entity receiving a ~~data~~ specification in Requirement R3 or R4 did not satisfy the ~~obligations of the~~ documented specification~~s for data~~.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					2.5 – 2.8).	

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1		Modified R1.2 Modified M1 Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs)	Revised
1	October 17, 2008	Adopted by NERC Board of Trustees	
1	March 17, 2011	Order issued by FERC approving TOP-003-1 (approval effective 5/23/11)	
2	May 6, 2012	Revised under Project 2007-03	Revised
2	May 9, 2012	Adopted by Board of Trustees	Revised
3	April 2014	Changes pursuant to Project 2014-03	Revised
3	November 13, 2014	Adopted by Board of Trustees	Revisions under Project 2014-03
3	November 19, 2015	FERC approved TOP-003-3. Docket No. RM15-16-000, Order No. 817	
4	February 6, 2020	Adopted by NERC Board of Trustees	Revisions under Project 2017-07
4	June 11, 2021	Board approved	Project 2019-06 Cold Weather

4	August 24, 2021	FERC approved TOP –003-5 Docket No. RD21-5-000, Order	
4	August 24, 2021	April 1, 2023	Effective Date
5		TBD	Revised under project 2021-06

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

This is the final draft of the proposed standard for a formal 8-day ballot period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR)	11/17/2021
SAR posted for comment	11/22/21 – 12/21/21
30-day formal comment period with ballot	5/19/22 – 6/21/22

Anticipated Actions	Date
8-day final ballot	9/23/22 – 9/30/22
NERC Board of Trustees (Board) adoption	October 2022

A. Introduction

1. **Title:** **Emergency ~~Preparedness and~~ Operations**

2. **Number:** **EOP-~~011-2~~011-3**

3. **Purpose:** To address the effects of operating ~~emergencies~~Emergencies by ensuring each Transmission Operator~~,~~ and Balancing Authority~~, and Generator Owner~~ has developed plan(s) to mitigate operating Emergencies and that those plans are implemented and coordinated within the Reliability Coordinator Area as specified within the requirements.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Balancing Authority

   4.1.2 Reliability Coordinator

   4.1.3 Transmission Operator

   ~~**3.0.4** Generator Owner~~

   ~~**3.1.5** Generator Operator~~

   ~~**4.2. Facilities**~~

   ~~**4.2.1** For the purpose of this standard, the term "generating unit" means all Bulk Electric System generators.~~

5. **Effective Date:** See Implementation Plan for Project ~~2019-06~~2021-07.

B. Requirements and Measures

R1. Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

1.1. Roles and responsibilities for activating the Operating Plan(s);

1.2. Processes to prepare for and mitigate Emergencies including:

1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency;

1.2.2. Cancellation or recall of Transmission and generation outages;

1.2.3. Transmission system reconfiguration;

1.2.4. Redispatch of generation request;

1.2.5. Operator-controlled manual Load shedding during an Emergency that accounts for each of the following:

1.2.5.1. ~~**1.2.5.**~~ Provisions for ~~operator-controlled~~ manual Load shedding ~~that minimizes the overlap with automatic Load shedding and are~~ capable of being implemented in a timeframe adequate for mitigating the Emergency;~~ and~~

1.2.5.2. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that serve designated critical loads;

1.2.5.3. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for underfrequency load shed (UFLS) or undervoltage load shed (UVLS); and

1.2.5.4. Provisions for limiting the utilization of UFLS or UVLS circuits for manual Load shed to situations where warranted by system conditions.

1.2.6. Provisions to determine reliability impacts of:

1.2.6.1. cold weather conditions; and

1.2.6.2. extreme weather conditions.

M1. Each Transmission Operator will have a dated Operating Plan(s) developed in accordance with Requirement R1 and reviewed by its Reliability Coordinator; evidence such as a review or revision history to indicate that the Operating Plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R1.

R2. Each Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

2.1. Roles and responsibilities for activating the Operating Plan(s);

2.2. Processes to prepare for and mitigate Emergencies including:

2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;

2.2.2. Requesting an Energy Emergency Alert, per Attachment 1;

2.2.3. Managing generating resources in its Balancing Authority Area to address:

2.2.3.1. capability and availability;

2.2.3.2. fuel supply and inventory concerns;

2.2.3.3. fuel switching capabilities; and

2.2.3.4. environmental constraints.

2.2.4. Public appeals for voluntary Load reductions;

2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions;

2.2.6. Reduction of internal utility energy use;

2.2.7. Use of Interruptible Load, curtailable Load and demand response;

2.2.8. Provisions for Transmission Operators to implement operator-controlled manual Load ~~shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency~~shed in accordance with Requirement R1 Part 1.2.5; and

2.2.9. Provisions to determine reliability impacts of:

2.2.9.1. cold weather conditions; and

2.2.9.2. extreme weather conditions.

M2. Each Balancing Authority will have a dated Operating Plan(s) developed in accordance with Requirement R2 and reviewed by its Reliability Coordinator; evidence such as a review or revision history to indicate that the Operating Plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings, or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R2.

R3. The Reliability Coordinator shall review the Operating Plan(s) to mitigate operating Emergencies submitted by a Transmission Operator or a Balancing Authority regarding any reliability risks that are identified between Operating Plans. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

3.1. Within 30 calendar days of receipt, the Reliability Coordinator shall:

3.1.1. Review each submitted Operating Plan(s) on the basis of compatibility and inter-dependency with other Balancing Authorities' and Transmission Operators' Operating Plans;

3.1.2. Review each submitted Operating Plan(s) for coordination to avoid risk to Wide Area reliability; and

3.1.3. Notify each Balancing Authority and Transmission Operator of the results of its review, specifying any time frame for resubmittal of its Operating Plan(s) if revisions are identified.

M3. The Reliability Coordinator will have documentation, such as dated ~~e-mails~~emails or other correspondences that it reviewed, Transmission Operator and Balancing Authority Operating Plans, within 30 calendar days of submittal in accordance with

Requirement R3.

R4. Each Transmission Operator and Balancing Authority shall address any reliability risks identified by its Reliability Coordinator pursuant to Requirement R3 and resubmit its Operating Plan(s) to its Reliability Coordinator within a time period specified by its Reliability Coordinator. *[Violation Risk Factor: High] [Time Horizon: Operation Planning]*

M4. The Transmission Operator and Balancing Authority will have documentation, such as dated emails or other correspondence, with an Operating Plan(s) version history showing that it responded and updated the Operating Plan(s) within the timeframe identified by its Reliability Coordinator in accordance with Requirement R4.

R5. Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area shall notify, within 30 minutes from the time of receiving notification, other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M5. Each Reliability Coordinator that receives an Emergency notification from a Balancing Authority or Transmission Operator within its Reliability Coordinator Area will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that will be used to determine if the Reliability Coordinator communicated, in accordance with Requirement R5, with other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators.

R6. Each Reliability Coordinator that has a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall declare an Energy Emergency Alert, as detailed in Attachment 1. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M6. Each Reliability Coordinator, with a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area, will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that it declared an Energy Emergency Alert, as detailed in Attachment 1, in accordance with Requirement R6.

~~**R7.** Each Generator Owner shall implement and maintain one or more cold weather preparedness plan(s) for its generating units. The cold weather preparedness plan(s) shall include the following, at a minimum: [*Violation Risk Factor: High*] [*Time Horizon: Operations Planning and Real-Time Operations*]~~

~~**7.1.** Generating unit(s) freeze protection measures based on geographical location and plant configuration;~~

~~**7.2.** Annual inspection and maintenance of generating unit(s) freeze protection measures;~~

~~**7.3.** Generating unit(s) cold weather data, to include:~~

~~**7.3.1.** Generating unit(s) operating limitations in cold weather to include:~~

~~**7.3.1.1.** capability and availability;~~

~~**7.3.1.2.** fuel supply and inventory concerns;~~

~~**7.3.1.3.** fuel switching capabilities; and~~

~~**7.3.1.4.** environmental constraints.~~

~~**7.3.2.** Generating unit(s) minimum:~~

~~**7.3.2.1.** design temperature; or~~

~~**7.3.2.2.** historical operating temperature; or~~

~~**7.3.1.3.** current cold weather performance temperature determined by an engineering analysis.~~

~~**M7.** Each Generator Owner will have evidence documenting that its cold weather preparedness plan(s) was implemented and maintained in accordance with Requirement R7.~~

~~**R8.** Each Generator Owner in conjunction with its Generator Operator shall identify the entity responsible for providing the generating unit-specific training, and that identified entity shall provide the training to its maintenance or operations personnel responsible for implementing cold weather preparedness plan(s) developed pursuant to Requirement R7. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning]*~~

~~**M8.** Each Generator Operator or Generator Owner will have documented evidence that the applicable personnel completed training of the Generator Owner's cold weather preparedness plan(s). This evidence may include, but is not limited to, documents such as personnel training records, training materials, date of training, agendas or learning objectives, attendance at pre-work briefings, review of work order tasks, tailboards, attendance logs for classroom training, and completion records for computer-based training in fulfillment of Requirement R8.~~

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

"Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with the 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~~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 applicable entity shall keep data or evidence to show compliance as identified below unless directed by its ~~Compliance Enforcement Authority~~CEA to retain specific evidence for a longer period of time as part of an investigation.

- The Transmission Operator shall retain the current Operating Plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R1 and R4 and Measures M1 and M4.

- The Balancing Authority shall retain the current Operating Plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R2 and R4, and Measures M2 and M4.
- The Reliability Coordinator shall maintain evidence of compliance since the last audit for Requirements R3, R5, and R6 and Measures M3, M5, and M6.

1.3. Compliance Monitoring and Enforcement Program:

- ~~The Generator Owner shall retain the cold weather preparedness plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirement R7 and Measure M7.~~

~~**1.3.** The Generator Owner or Generator Operator shall keep data or evidence to show compliance for three years or since its last compliance audit, whichever timeframe is greater, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation, for Requirement R8 and Measure M8.~~ ~~**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	Real-time Operations, Operations Planning, Long-term Planning	High	N/A	The Transmission Operator developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to maintain it.	The Transmission Operator developed an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to have it reviewed by its Reliability Coordinator.	The Transmission Operator failed to develop an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. OR The Transmission Operator developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission ~~s~~ Operator Area, but failed to implement it.
R2	Real-time Operations, Operations	High	N/A	The Balancing Authority developed a Reliability Coordinator-	The Balancing Authority developed an Operating Plan(s) to mitigate operating	The Balancing Authority failed to develop an

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
	Planning, Long-term Planning			reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to maintain it.	Emergencies within its Balancing Authority Area, but failed to have it reviewed by its Reliability Coordinator.	Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area. OR The Balancing Authority developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to implement it.
R3	Operations Planning	High	N/A	N/A	The Reliability Coordinator identified a reliability risk, but failed to notify the Balancing Authority or Transmission	The Reliability Coordinator identified a reliability risk, but failed to notify the Balancing Authority or Transmission Operator.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					Operator within 30 calendar days.	
R4	Operations Planning	High	N/A	N/A	The Transmission Operator or Balancing Authority failed to update and resubmit ~~tis~~its Operating Plan(s) to its Reliability Coordinator within the timeframe specified by its Reliability Coordinator.	The Transmission Operator or Balancing Authority failed to update and resubmit its Operating Plan(s) to its Reliability Coordinator.
R5	Real-time Operations	High	N/A	N/A	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority did notify neighboring Reliability Coordinators, Balancing Authorities	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority failed to notify neighboring Reliability Coordinators, Balancing Authorities

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					and Transmission Operators, but failed to notify within 30 minutes from the time of receiving notification.	and Transmission Operators.
R6	Real-time Operations	High	N/A	N/A	N/A	The Reliability Coordinator that had a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area failed to declare an Energy Emergency Alert.
~~**R7**~~	~~Operations Planning and Real-time Operations~~	~~High~~	~~The Generator Owner implemented a cold weather preparedness plan(s) but failed to maintain it.~~	~~The Generator Owner's cold weather preparedness plan failed to include one of the applicable requirement Parts within Requirement R7.~~	~~The Generator Owner had and maintained a cold weather preparedness plan(s) but failed to fully implement it.~~ ~~OR~~	~~The Generator Owner does not have a cold weather preparedness plan.~~ ~~OR~~ ~~The Generator Owner has a cold~~

~~R #~~	~~Time Horizon~~	~~VRF~~	~~Violation Severity Levels~~			
			~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
					~~The Generator Owner's cold weather preparedness plan failed to include two of the applicable requirement Parts within Requirement R7.~~	~~weather preparedness plan, but failed to include any of the applicable requirement Parts within Requirement R7.~~
~~R8~~	~~Operations Planning and Real-time Operations~~	~~Medium~~	~~The Generator Owner or Generator Operator failed to provide generating unit-specific training as described in Requirement R8 to the greater of:~~ • ~~one applicable personnel at a single generating unit; or~~ • ~~5% or less of its total applicable personnel.~~	~~The Generator Owner or Generator Operator failed to provide generating unit-specific training as described in Requirement R8 to the greater of:~~ • ~~two applicable personnel at a single generating unit; or~~ • ~~more than 5% or less than or equal to 10% of its total applicable personnel.~~	~~The Generator Owner or Generator Operator failed to provide generating unit-specific training as described in Requirement R8 to the greater of:~~ • ~~three applicable personnel at a single generating unit; or~~ • ~~more than 10% or less than or equal to 15% of its total applicable personnel.~~	~~The Generator Owner or Generator Operator failed to provide generating unit-specific training as described in Requirement R8 to the greater of:~~ • ~~four applicable personnel at a single generating unit; or~~ • ~~more than 15% of its total applicable personnel.~~

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	November 13, 2014	Adopted by Board of Trustees	Merged EOP-001-2.1b, EOP-002-3.1 and EOP-003-2.
1	November 19, 2015	FERC approved EOP-011-1. Docket Nos. RM15-7-000, RM15-12-000, and RM15-13-000. Order No. 818	
2	June 11,2021	Adopted by ~~the~~ Board of Trustees	Revised under Project 2019-06
2	August 24,2021	FERC approved EOP-011-2. Docket Number RD21-5-000	
2	August 24,2021	Effective Date	4/1/ 2023
3	TBD		Revised under Project 2021-07

Attachment 1-EOP-~~011-2~~011-3 Energy Emergency Alerts

Introduction

This Attachment provides the process and descriptions of the levels used by the Reliability Coordinator in which it communicates the condition of a Balancing Authority which is experiencing an Energy Emergency.

A. General Responsibilities

1. **Initiation by Reliability Coordinator.** An Energy Emergency Alert (EEA) may be initiated only by a Reliability Coordinator at 1) the Reliability Coordinator's own request, or 2) upon the request of an energy deficient Balancing Authority.

2. **Notification**. A Reliability Coordinator who declares an EEA shall notify all Balancing Authorities and Transmission Operators in its Reliability Coordinator Area. The Reliability Coordinator shall also notify all neighboring Reliability Coordinators.

B. EEA Levels

Introduction

To ensure that all Reliability Coordinators clearly understand potential and actual Energy Emergencies in the Interconnection, NERC has established three levels of EEAs. The Reliability Coordinators will use these terms when communicating Energy Emergencies to each other. An EEA is an Emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC Reliability Standards.

The Reliability Coordinator may declare whatever alert level is necessary, and need not proceed through the alerts sequentially.

1. **EEA 1 — All available generation resources in use. Circumstances:**

   - The Balancing Authority is experiencing conditions where all available generation resources are committed to meet firm Load, firm transactions, and reserve commitments, and is concerned about sustaining its required Contingency Reserves.
   - Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.

2. **EEA 2 — Load management procedures in effect. Circumstances:**

   - The Balancing Authority is no longer able to provide its expected energy requirements and is an energy deficient Balancing Authority.
   - An energy deficient Balancing Authority has implemented its Operating Plan(s) to mitigate Emergencies.

- An energy deficient Balancing Authority is still able to maintain minimum Contingency Reserve requirements.

During EEA 2, Reliability Coordinators and energy deficient Balancing Authorities have the following responsibilities:

2.1 Notifying other Balancing Authorities and market participants. The energy deficient Balancing Authority shall communicate its needs to other Balancing Authorities and market participants. Upon request from the energy deficient Balancing Authority, the respective Reliability Coordinator shall post the declaration of the alert level, along with the name of the energy deficient Balancing Authority on the RCIS website.

2.2 Declaration period. The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 2 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators**.**

2.3 Sharing information on resource availability. Other Reliability Coordinators of Balancing Authorities with available resources shall coordinate, as appropriate, with the Reliability Coordinator that has an energy deficient Balancing Authority.

2.4 Evaluating and mitigating Transmission limitations. The Reliability Coordinator shall review Transmission outages and work with the Transmission Operator(s) to see if it's possible to return to service any Transmission Elements that may relieve the loading on System Operating Limits (SOLs) or Interconnection Reliability Operating Limits (IROLs).

2.5 Requesting Balancing Authority actions. Before requesting an EEA 3, the energy deficient Balancing Authority must make use of all available resources; this includes, but is not limited to:

2.5.1 All available generation units are on line. All generation capable of being on line in the time frame of the Emergency is on line.

2.5.2 Demand-Side Management. Activate Demand-Side Management within provisions of any applicable agreements.

3. EEA 3 —Firm Load interruption is imminent or in progress. Circumstances:

- The energy deficient Balancing Authority is unable to meet minimum Contingency Reserve requirements.

During EEA 3, Reliability Coordinators and Balancing Authorities have the following responsibilities:

3.1 Continue actions from EEA 2. The Reliability Coordinators and the energy deficient Balancing Authority shall continue to take all actions initiated during EEA 2.

3.2 Declaration Period. The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 3 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the neighboring Reliability Coordinators, Balancing Authorities, and Transmission Operators.

3.3 Reevaluating and revising SOLs and IROLs. The Reliability Coordinator shall evaluate the risks of revising SOLs and IROLs for the possibility of delivery of energy to the energy deficient Balancing Authority. Reevaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinators and only with the agreement of the Transmission Operator whose Transmission Owner (TO) equipment would be affected. SOLs and IROLs shall only be revised as long as an EEA 3 condition exists, or as allowed by the Transmission Owner whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised:

3.3.1 Energy deficient Balancing Authority obligations. The energy deficient Balancing Authority, upon notification from its Reliability Coordinator of the situation, ~~it~~ will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include Load shedding.

3.4 Returning to pre-Emergency conditions. Whenever energy is made available to an energy deficient Balancing Authority such that the Systems can be returned to its pre- Emergency SOLs or IROLs condition, the energy deficient Balancing Authority shall request the Reliability Coordinator to downgrade the alert level.

3.4.1 Notification of other parties. Upon notification from the energy deficient Balancing Authority that an alert has been downgraded, the Reliability Coordinator shall notify the neighboring Reliability Coordinators (via the RCIS), Balancing Authorities, and Transmission Operators that its Systems can be returned to its normal limits.

Alert 0 - Termination. When the energy deficient Balancing Authority is able to meet its Load and Operating Reserve requirements, it shall request its Reliability Coordinator to terminate the EEA.

3.4.2 Notification. The Reliability Coordinator shall notify all other Reliability Coordinators via the RCIS of the termination. The Reliability Coordinator shall also notify the neighboring Balancing Authorities and Transmission Operators.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

This is the ~~second~~ final draft of the proposed standard for a formal ~~30~~8-day ~~comment~~ ballot period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	11/17/2021
SAR posted for comment	11/22/21 – 12/21/21
30-day formal or informal comment period with ballot	5/19/22 – 6/21/22

~~Anticipated Actions~~	~~Date~~
30-day formal or informal comment period with additional ballot	8/3/22- 9/1/22

Anticipated Actions	Date
~~10~~8-day final ballot	~~September 2022~~9/23/22 – 9/30/22
Board adoption	October 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):

Generator Cold Weather Critical Component - Any generating unit component or associated fixed fuel supply component, that is under the Generator Owner's control, and is susceptible to freezing issues, the occurrence of which would likely lead to a Generator Cold Weather Reliability Event.

Extreme Cold Weather Temperature – The temperature equal to the lowest 0.2 percentile of the hourly temperatures measured in December, January, and February from 1/1/2000 through the date the temperature is calculated.

Generator Cold Weather Reliability Event - One of the following events for which the apparent cause(s) is due to freezing of equipment within the Generator Owner's control and the dry bulb temperature at the time of the event was at or above the Extreme Cold Weather Temperature:

(1) a forced derate of more than 10% of the total capacity of the unit and exceeding 20 MWs for longer than four hours in duration;

(2) a start-up failure where the unit fails to synchronize within a specified start-up time; or

(3) a Forced Outage~~,~~.

~~for which the apparent cause(s) is due to freezing of equipment within the Generator Owner's control and the dry bulb temperature at the time of the event was at or above the Extreme Cold Weather Temperature.~~

A. Introduction

1. **Title:** **Extreme Cold Weather Preparedness and Operations**

2. **Number:** EOP-012-1

3. **Purpose:** To address the effects of operating in extreme cold weather by ensuring each Generator Owner has developed and implemented plan(s) to mitigate the reliability impacts of extreme cold weather on its generating units.

4. **Applicability:**

4.1. Functional Entities:

4.1.1. Generator Owner

4.1.2. Generator Operator

4.2. Facilities:

4.2.1 ~~**4.2. Facilities:**~~ For purposes of this standard, the term "generating unit" subject to these requirements ~~means~~refers to the following Bulk Electric System (BES) resources:

4.2.1.1 ~~**4.2.1**~~ A Bulk Electric System generating unit~~:~~

~~**4.2.1.1**~~ that ~~That~~ commits or is obligated to serve a Balancing Authority load pursuant to ~~an Open Access Transmission Tariff (OATT)~~a tariff obligation, state requirement as defined by the relevant electric regulatory authority, or other contractual arrangement~~;~~, rule, or regulation, for a continuous run of four hours or more at or below a temperature of 32 degrees Fahrenheit (zero degrees Celsius); or

4.2.1.2 A Blackstart Resource

4.2.2 Exemptions:

4.2.2.1 Any Bulk Electric System generating unit included under Section 4.2.1 above that has a calculated Extreme Cold Weather Temperature exceeding 32 degrees Fahrenheit (zero degrees Celsius) under Requirement R3 Part 3.1 and as part of the required five year review in Requirement R4 Part 4.1 is exempt from further requirements in this standard.

4.2.2.2 ~~**4.2.1.1.1** The term excludes a~~A Bulk Electric System generating unit that is ~~typically not available~~not committed or obligated to operate at or below ~~thirty-two (~~a temperature of 32~~)~~ degrees Fahrenheit (zero degrees Celsius) for any continuous run of more than four hours~~. The exclusion applies even when such BES generator has been called~~, but is called upon to operate for more than four hours in order to assist in the mitigation of BES Emergencies, Capacity Emergencies, or Energy Emergencies during periods at or below a temperature of 32 degrees Fahrenheit (zero degrees Celsius).

~~4.2.1.2 That is identified as a Blackstart Resource.~~

5. Effective Date: See Implementation Plan for Project 2021-07.

B. Requirements and Measures

R1. For each generating unit(s) with a commercial operation date subsequent to [Effective Date of this requirement], the Generator Owner shall: [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning, Operations Planning*]

- Implement freeze protection measures that provide capability to operate for a period of not less than twelve (12) continuous hours at the Extreme Cold Weather Temperature for the unit(s), assuming a concurrent twenty (20) mph wind speed on any exposed Generator Cold Weather Critical Components; or
- Explain in a declaration~~,~~ any technical, commercial, or operational constraints, as defined by the Generator Owner, that preclude the ability to implement appropriate freeze protection measures to provide capability of operating for twelve (12) hours at the documented Extreme Cold Weather Temperature.~~.~~

M1. Each Generator Owner will have dated evidence that demonstrates it has the capability to operate in accordance with Requirement R1. Acceptable evidence may include, but is not limited to, the following (electronic or hardcopy format): Documentation of cold weather preparedness plan, documentation of design features~~. Any~~, any declaration that contains dated documentation to support constraints identified by the Generator Owner.

R2. For each generating unit(s) in commercial operation prior to [Effective Date of this requirement], the Generator Owner shall ensure its generating unit(s) add new or modify existing freeze protection measures as needed to provide the capability to operate for a period of not less than one (1) hour at the unit(s) Extreme Cold Weather Temperature. Generating unit(s) that are not capable of operating for one (1) hour at its Extreme Cold Weather Temperature shall develop a Corrective Action Plan (CAP) for the identified issues, including identification of any needed modifications to the cold weather preparedness plan required under Requirement R3. [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning, Operations Planning*]

M2. Each Generator Owner will have dated evidence that demonstrates it has freeze protection measures for its unit(s) in accordance with R2, or it has developed a CAP for the identified issues. Acceptable evidence may include the following (electronic or hardcopy format): Identification of generating units minimum temperature per Part 3.5.2 which is equal to or less than the unit's Extreme Cold Weather Temperature, documentation of freeze protection measures, cold weather preparedness plan, and CAP(s).

R3. Each Generator Owner shall implement and maintain one or more cold weather preparedness plan(s) for its generating units. The cold weather preparedness plan(s) shall include the following, at a minimum: *[Violation Risk Factor: High] [Time Horizon: Operations Planning and Real-time Operations]*

3.1 The Extreme Cold Weather Temperature for their unit(s) including the calculation date and source of temperature data;

3.2 Documentation identifying the Generator Cold Weather Critical Components;

3.3 Documentation of freeze protection measures implemented on Generator Cold Weather Critical Components which may include measures used to reduce the cooling effects of wind determined necessary by the Generator Owner to protect against heat loss, and where applicable, the effects of freezing precipitation (e.g., sleet, snow, ice, and freezing rain);

3.4 Annual inspection and maintenance of generating unit(s) freeze protection measures; and

3.5 Generating unit(s) cold weather data, to include:

3.5.1 Generating unit(s) operating limitations in cold weather to include:

3.5.1.1 Capability and availability;

3.5.1.2 Fuel supply and inventory concerns;

3.5.1.3 Fuel switching capabilities; and

3.5.1.4 Environmental constraints.

3.5.2 Generating unit(s) minimum:

- Design temperature;
- Historical operating temperature; or
- Current cold weather performance temperature determined by an engineering analysis.

M3. Each Generator Owner will have evidence documenting that its cold weather preparedness plan(s) was implemented and maintained in accordance with Requirement R3.

R4. Once every five calendar years, each Generator Owner shall for each generating unit: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning, Real-Time Operations]*

4.1 Calculate the Extreme Cold Weather Temperature, and update the cold weather preparedness plan if this temperature is now lower than the previous lowest calculation;

4.2 Review its documented generating unit(s) minimum temperature contained within its cold weather preparedness plan(s), pursuant to Part 3.5.2; and

4.3 Review whether its generating units have the freeze protection measures required to operate at the Extreme Cold Weather Temperature pursuant to R1 or R2 as applicable, and if not develop a CAP for the identified issues, including identification of any needed modifications to the cold weather preparedness plan required under Requirement R3.

M4. Each Generator Owner will have dated, documented evidence ~~documenting~~ that it reviewed ~~documented~~ temperature data and updated its cold weather preparedness plan(s) in accordance with Requirement R4.

R5. Each Generator Owner in conjunction with its Generator Operator shall identify the entity responsible for providing the generating unit-specific training, and that identified entity shall provide annual training to its maintenance or operations personnel responsible for implementing the cold weather preparedness plan(s) developed pursuant to Requirement R3. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning]*

M5. Each Generator Operator or Generator Owner will have documented evidence that the applicable personnel completed annual training of the Generator Owner's cold weather preparedness plan(s). This evidence may include, but is not limited to, documents such as personnel training records, training materials, date of training, agendas or learning objectives, attendance at pre-work briefings, review of work order tasks, tailboards, attendance logs for classroom training, and completion records for computer-based training in fulfillment of Requirement R5.

R6. Each Generator Owner that owns a generating unit that experiences a Generator Cold Weather Reliability Event shall develop a CAP, within 150 days or by July 1, whichever is earlier, that contains at a minimum: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

6.1 A summary of the identified cause(s) for the Generator Cold Weather Reliability Event, where applicable, and any relevant associated data;

6.2 A review of applicability to similar equipment at other generating units owned by the Generator Owner;

6.3 An identification of any temporary operating limitations or impacts to the cold weather preparedness plan, that would apply until execution of the corrective action(s) identified in the CAP.

M6. Each Generator Owner will have documented evidence that it developed a CAP in accordance with Requirement R6. Acceptable evidence ~~for these requirements~~ may include, but is not limited to, the following dated documentation (electronic or hardcopy format): CAP(s) and updated cold weather preparedness plan(s) where indicated as needed by the CAP. ~~Any declaration shall contain dated documentation to support constraints identified by the Generator Owner.~~

R7. Each Generator Owner shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

7.1 Implement each CAP developed pursuant to Requirements R2, R4, or R6, or explain in a declaration why corrective actions are not being implemented due to any technical, commercial, or operational constraints as defined by the Generator Owner.

7.2 Update each CAP if actions or timetables change, until completed.

M7. Each Generator Owner shall have dated evidence that demonstrates it implemented each CAP, including updating actions or timetables, or has explained in a declaration why corrective actions are not being implemented in accordance with Requirement R7. Acceptable evidence ~~for Requirement R7~~ may include, but is not limited to the following dated documentation (electronic or hardcopy format): records that document the implementation of each CAP and the completion of actions for each CAP including revision history of each CAP. Evidence may also include work management program records, work orders, and maintenance records. Any declaration shall contain dated documentation to support constraints identified by the Generator Owner.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable 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 applicable 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 Generator Owner shall keep data or evidence to show compliance for three years for Requirement R1, R3, and R5 and Measure M1, M3, and M5.
- The Generator Owner shall keep data or evidence to show compliance for three years, or until any Corrective Action Plan under Requirement R2 is complete, whichever timeframe is greater, for Requirement R2 and Measure M2.
- The Generator Owner shall retain the current cold weather preparedness plan(s), as evidence of review or revision history, plus each version issued since the last audit and evidence of compliance since the last audit for

Requirement R4 and Measure M4. The Generator Owner shall retain any Corrective Action Plans under Requirement R4 Part 4.3 for three years or until the Corrective Action Plan is complete, whichever timeframe is greater.

- The Generator Owner shall keep data or evidence to show compliance for three years, or until any Corrective Action Plan under Requirement R6 is complete, whichever timeframe is greater, for Requirement R6 and Measure M6.
- The Generator Owner shall keep data or evidence to show compliance for three years, or until any Corrective Action Plan is complete, whichever time frame is greater, for Requirement R7 and Measure M7.

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

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R1 for 5% or less of its units. OR The Generator Owner did not explain in a declaration any technical, commercial, or operational constraints that preclude the ability to implement appropriate freeze protection measures for 5% or less of its units.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R1 for more than 5%, but less than or equal to 10% of its units. OR The Generator Owner did not explain in a declaration any technical, commercial, or operational constraints that preclude the ability to implement appropriate freeze protection measures for more than 5%, but less than or equal to 10% of its units.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R1 for more than 10%, but less than or equal to 20% of its units. OR The Generator Owner did not explain in a declaration any technical, commercial, or operational constraints that preclude the ability to implement appropriate freeze protection measures for more than 10%, but less than or equal to 20% of its units.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R1 for more than 20% of its units. OR The Generator Owner did not explain in a declaration any technical, commercial, or operational constraints that preclude the ability to implement appropriate freeze protection measures for more than 20% of its units.
R2.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R2 for 5% or less of its units. OR The Generator Owner did not develop a CAP as required by	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R2 for more than 5%, but less than or equal to 10% of its units. OR The Generator Owner did not develop a CAP as required by Requirement R2 for more than	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R2 for more than 10%, but less than or equal to 20% of its units. OR The Generator Owner did not develop a CAP as required by Requirement R2 for more than	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R2 for more than 20% of its units. OR The Generator Owner did not develop a CAP as required by

	Requirement R2 for 5% or less of its units.	5%, but less than or equal to 10% of its units.	10%, but less than or equal to 20% of its units.	Requirement R2 for more than 20% of its units.
R3.	The Generator Owner implemented a cold weather preparedness plan(s), but failed to maintain it.	The Generator Owner's cold weather preparedness plan failed to include one of the applicable Parts within Requirement R3.	The Generator Owner had and maintained a cold weather preparedness plan(s), but failed to implement it. OR The Generator Owner's cold weather preparedness plan failed to include two of the applicable requirement parts within Requirement R3.	The Generator Owner does not have cold weather preparedness plan(s). OR The Generator Owner's cold weather preparedness plan failed to include three or more of the applicable requirement parts within Requirement R3.
R4.	The Generator Owner completed the actions required in Requirement R4, but was late by 30 calendar days or less.	The Generator Owner completed the actions required in Requirement R4, but was late by greater than 30 calendar days, but less than or equal to 60 calendar days.	The Generator Owner failed to complete one of the applicable requirement parts in Requirement R4 Parts 4.1 through 4.3; OR The Generator Owner completed the actions required in Requirement R4, but was late by greater than 60 calendar days.	The Generator Owner failed to complete two or more of the applicable requirement parts in Requirement R4 Parts 4.1 through 4.3.
R5.	The Generator Owner or Generator Operator failed to provide annual generating unit-specific training as described in Requirement R5 to the greater of:	The Generator Owner or Generator Operator failed to provide annual generating unit-specific training as described in Requirement R5 to the greater of:	The Generator Owner or Generator Operator failed to provide annual generating unit-specific training as described in Requirement R5 to the greater of:	The Generator Owner or Generator Operator failed to provide annual generating unit-specific training as described in Requirement R5 to the greater of:

	• one applicable personnel at a single generating unit; or • 5% or less of its total applicable personnel.	• two applicable personnel at a single generating unit; or • more than 5%, but less than or equal to 10% of its total applicable personnel.	• three applicable personnel at a single generating unit; or • more than 10%, but less than or equal to 15% of its total applicable personnel.	• four applicable personnel at a single generating unit; or • more than 15% of its total applicable personnel.
R6.	The Generator Owner developed a CAP, but not within 150 days or by July 1 as required in Requirement R6.	The Generator Owner's CAP failed to comply with one of the elements in Requirement R6, Parts 6.1 through 6.3.	The Generator Owner's CAP failed to comply with two of the elements in Requirement R6, Parts 6.1 through 6.3.	The Generator Owner's CAP failed to comply with three of the elements in Requirement R6, Parts 6.1 through 6.3. OR The Generator Owner did not develop a CAP as required by Requirement ~~R7~~R6.
R7.	The Generator Owner implemented a CAP or explained in a declaration why corrective actions are not being implemented, but failed to update the CAP when actions or timetables changed, in accordance with Requirement R7.			The Generator Owner failed to implement a CAP or explain in a declaration why corrective actions are not being implemented in accordance with Requirement R7.

D. Regional Variances

None.

E. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	TBD	Drafted by Project 2021-07	New

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

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:	FAC-008 Facility Ratings		
Date Submitted:	07-14-2021 (Revised on August 16, 2022)		
SAR Requester			
Name:	Ryan Walter (Revised by Project 2021-08 SAR Drafting Team)		
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~~			

Requested information
~~capable of, which could be detrimental to reliability during actual system emergencies. Explicitly allowing the inclusion of mechanical elements in the development of Facility Ratings will ensure Generators are rated to their most limiting element.~~ The Standard Drafting Team will review Requirement 1 and determine changes, if any, which are necessary to ensure reliability while removing redundancy and administrative burdens from the standard. Further, the term “jointly owned” as used in FAC-008-~~3~~ 5 ~~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”.~~ allows for inconsistent application across the ERO. The Standard Drafting team should examine the appropriate level of data sharing between entities to support consistent Facility Ratings and support the development of System Operating Limits. Ensure that Requirement R6 is reviewed as a risk-based Requirement.
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” as it applies to FAC-008, 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).~~Examine the appropriateness and effectiveness of Requirement 1 for the development of Facility Ratings information for Generation Facilities. 3. Ensure that Requirement R6 is reviewed as a risk-based Requirement.
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):
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~~

[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
~~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.~~examined to determine its continued effectiveness. Since the development of FAC-008 there have been several additional Reliability Standards developed which request similar or redundant information as FAC-008 Requirement 1. The additional standards that can be considered are IRO-010, MOD-025, MOD-032, TOP-003, and possibly others. The Standard Development Team will review Requirement 1 and determine changes, if any, which are necessary ~~to provide~~ to ensure reliability while removing redundancy and administrative burdens from the standard. Generator Facility Ratings and capability information 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." The burden of Facility Rating documentation is unclear in 'jointly-owned' facilities. The ERO Enterprise CMEP Practice Guide interprets this burden as each owner maintaining all the equipment ratings of their own equipment and the Most Limiting Series Element of the 'jointly-owned' owner. This burden has been inconsistently understood. The SDT should examine the appropriate level of data sharing between entities to support consistent Facility Ratings and support the development of System Operating Limits. If the SDT determines that Facility Ratings data is required to be shared between owners, the SAR DT suggests that the applicable entity should be required to provide the most limiting equipment rating for its jointly owned facilities. For Generation Owners specifically, Requirement 2 obligates GOs to obtain Facility Rating information from the interconnecting Owners of jointly owned Facilities. However, the requirement R8 does not provide the Generator Owner with the authority to request Facility Rating information from other entities. Per the requirement, Facility owners only need to provide request Facility Rating information to the following entities: Reliability Coordinator(s), Planning Coordinator(s), Transmission Planner(s), Transmission Owner(s) and Transmission Operator(s). Without modifications, Generator Owners are placing in a situation where they are required to have data that they may not be able to obtain. Additionally, Requiring Generator Owners to obtain rating information from interconnecting Transmission Owners of jointly owned Facilities provides no additional benefit to reliability and is an administrative burden that can be eliminated. Generator Owners do not develop SOLs and should only be obligated to provide data for the equipment they own.

Requested information
The use of the term "consistent" in Requirement R6 can be interpreted that all inconsistencies in Facility Ratings pose an equal risk to the BES. The SAR team suggests data errors not affecting the overall Facility Rating does not produce a risk to the BES nor is it inconsistent with the statement that 'a Facility Rating shall respect the most limiting applicable Equipment Rating of the individual equipment that comprises that facility.' The SDT shall consider additional wording/guidance to ensure the standard is focused on BES reliability rather than data collection. The objectives of this SAR could be addressed in various ways. Here are a few ideas: 1. Alter, modify, or eliminate ~~the language within~~ FAC-008, R1 to provide information necessary for the development of appropriate planning models and system operating limits.~~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.*~~ 2. ~~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.~~The SDT will review the use of the term "jointly owned" and clarify, modify, or eliminate its use from the FAC-008 Reliability Standard.

Requested information
3. Review the language of Requirements 1, 2, 3, 6, and 8, and the "Compliance Assessment Approach" section of the RSAW. Determine if additional guidance or modifications are required to ensure R6 is risk based in nature.
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):
~~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.~~None identified at this time.
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.

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

Requested information
Are there 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, Implementation 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.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Market Interface Principles	
Does the proposed standard development project comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
e.g., NPCC	

For Use by NERC Only

SAR Status Tracking (Check off as appropriate).	
☐ Draft SAR reviewed by NERC Staff ☐ Draft SAR presented to SC for acceptance ☐ DRAFT SAR approved for posting by the SC	☐ Final SAR endorsed by the SC ☐ SAR assigned a Standards Project by NERC ☐ SAR denied or proposed as Guidance document

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	January 18, 2017	Standards Information Staff	Revised
2	June 28, 2017	Standards Information Staff	Updated template
3	February 22, 2019	Standards Information Staff	Added instructions to submit via Help Desk
4	February 25, 2020	Standards Information Staff	Updated template footer

Line	Project	[illegible]	Ballot Type	Start Date	End Date	Ballot Results	Recommendation / Date	[illegible]	Comments
1	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]			
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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%			
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%			
109	Project 2009-27	Project 2009-27 - Interpretation - TOP-002-2a for FMPAA_in	Initial Ballot	2/10/2010	2/22/2010	Quorum: 84.98% Approval: 90.82%			
110	Project 2009-28	Project 2009-28 - Interpretation - EOP-001-1 and EOP-001-2 for FMPP_in	Initial Ballot	2/10/2010	2/22/2010	Quorum: 87.36% Approval: 91.79%			
111	Project 2009-29	Project 2009-29 - Interpretation - TOP-002-2a for FMPP_in	Initial Ballot	2/11/2010	2/22/2010	Quorum: 84.34% Approval: 84.56%			
112	Project 2009-19	Project 2009-19 - Interpretation - BAL-002-0 Northwest Power Pool RSG_in	Initial Ballot	2/15/2010	2/26/2010	Quorum: 89.83% Approval: 48.60%			
113	Project 2009-20	Project 2009-20 - Interpretation - BAL-003-0 - Energy Mark, Inc._rc	Recirculation Ballot	2/16/2010	2/26/2010	Quorum: 92.44% Approval: 91.90%			
114	Project 2009-30	Project 2009-30 - Interpretation - PRC-001-1 for WPSC_in	Initial Ballot	2/15/2010	2/26/2010	Quorum: 89.51% Approval: 48.74%			
115	Project 2006-02	Project 2006-02 - Assess Transmission Future Needs - TPL-001-1_in	Initial Ballot	2/19/2010	3/1/2010	Quorum: 91.38% Approval: 35.36%			
116	Project 2009-31	Project 2009-31 - Interpretation - TOP-001-1 for FMPP_in	Initial Ballot	3/3/2010	3/16/2010	Quorum: 88.24% Approval: 98.27%			
117	Project 2009-06	Project 2009-06 - Facility Ratings: FAC-008-2	Recirculation Ballot	3/8/2010	3/18/2010	Quorum: 93.71% Approval: 78.15%			
118	Project 2009-32	Project 2009-32 - Interpretation - EOP-003-1 for FMPP_rb	Re-ballot	3/10/2010	3/31/2010	Quorum: 91.37% Approval: 77.66%			
119	Project 2009-23	Project 2009-23 - Interpretation - CIP-004-2 - U.S. Army Corps of Engineers (Revision 1)_in	Initial Ballot	3/29/2010	4/8/2010	Quorum: 88.52% Approval: 63.43%			
120	Project 2008-09	Project 2008-09 - Interpretation - RECM - Revision 3_in	Initial Ballot	4/15/2010	4/26/2010	Quorum: 81.97% Approval: 98.64%			
121	SPM	Standards Process Manual Revisions_in	Initial Ballot	4/19/2010	4/29/2010	Quorum: 87.82% Approval: 80.48%			
122	Project 2009-17	Project 2009-17 - Interpretation Y-W Electric and Tri-State (Revision 2)_in	Initial Ballot	4/28/2010	5/10/2010	Quorum: 83.15% Approval: 74.55%			
123	SPM	Standards Process Manual Revisions_rc	Recirculation Ballot	4/30/2010	5/10/2010	Quorum: 93.73% Approval: 86.69%			
124	Project 2010-11	Project 2010-11 SAR for TPL Table 1 Order_in	Initial Ballot	5/17/2010	5/27/2010	Quorum: 84.41% Approval: 63.75%			
125	Project 2010-09	Project 2010-09: NUC Implementation Plans for CIP Version 2 and Version 3_in	Initial Ballot	5/19/2010	6/1/2010	Quorum: 84.83% Approval: 90.83%			
126	Project 2010-09	Project 2010-09: NUC Implementation Plans for CIP Version 2 and Version 3_rc	Recirculation Ballot	6/22/2010	7/2/2010	Quorum: 89.10% Approval: 87.24%			
127	Project 2006-04	Project 2006-04 - Backup Facilities - Revision 1_in	Initial Ballot	6/23/2010	7/6/2010	Quorum: 89.05% Approval: 79.45%			
128	Project 2006-08	Project 2006-08 - Reliability Coordination - Transmission Loading Relief_in	Initial Ballot	6/23/2010	7/6/2010	Quorum: 87.04% Approval: 84.98%			
129	Project 2007-01	Project 2007-01 Underfrequency Load Shedding: PRC-006-1 and EOP-003-1	Initial Ballot	7/7/2010	7/17/2010	Quorum: 86.94% Approval: 43.13%			
130	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005-2	Initial Ballot	7/8/2010	7/17/2010	Quorum:91.12 % Approval: 22.91%			
131	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005-2	Non-binding Poll	7/8/2010	7/17/2010	Quorum: 86.00% Approval: 28.00%			
132	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: Protection System definition	Initial Ballot	7/8/2010	7/17/2010	Quorum: 87.85% Approval: 39.35%			
133	Project 2007-07	Project 2007-07 Vegetation Management: FAC-003-2	Initial Ballot	7/9/2010	7/19/2010	Quorum: 86.18% Approval: 65.93%			
134	Project 2006-04	Prokect 2006-04 - Backup Facilities - Revision 1_rc	Recirculation Ballot	7/16/2010	7/26/2010	Quorum: 93.43% Approval: 85.22%			
135	Project 2007-17	Project 2007-17 Protection System Maintenance: Protection System definition	Successive Ballot	7/23/2010	8/2/2010	Quorum: 94.70% Approval: 58.61%			
136	Project 2007-01	Project 2007-01 Underfrequency Load Shedding: PRC-006-1 and EOP-003-1	Successive Ballot	7/24/2010	8/3/2010	Quorum: 92.99% Approval: 49.61%			
137	Project 2006-08	Project 2006-08 - Reliability Coordination - Transmission Loading Relief_rc	Recirculation Ballot	8/20/2010	8/30/2010	Quorum: 88.26% Approval: 93.93%			
138	Project 2007-04	Project 2007-04 - Certifying System Operators: PER-003-1	Initial Ballot	9/14/2010	9/24/2010	Quorum: 92.73% Approval: 79.17%			
139	Project 2010-15	Project 2010-15 - Urgent Action Revisions to CIP-005-3	Initial Ballot	9/17/2010	9/27/2010	Quorum: 96.46% Approval: 21.77%			
140	Project 2007-01	Project 2007-01 Underfrequency Load Shedding: PRC-006-1 and EOP-003-1	Successive Ballot	9/24/2010	10/4/2010	Quorum: 85.71% Approval: 81.72%			
141	Project 2007-17	Project 2007-17 Protection System Maintenance: Protection System definition	Successive Ballot	10/2/2010	10/14/2010	Quorum: 84.11% Approval: 84.52%			
142	Project 2008-09	Project 2008-09 - Interpretation - RECM - Revision 3_rc	Recirculation Ballot	10/4/2010	10/14/2010	Quorum: 88.11% Approval: 99.14%			
143	Project 2009-28	Project 2009-28 - Interpretation - EOP-001-1 and EOP-001-2 for FMPP_rc	Recirculation Ballot	10/5/2010	10/15/2010	Quorum: 92.19% Approval: 94.78%			
144	Project 2009-27	Project 2009-27 - Interpretation - TOP-002-2a for FMPAA_rc	Recirculation Ballot	10/6/2010	10/16/2010	Quorum: 91.21% Approval: 93.44%			
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		

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
167	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-009-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.61% Approval: 27.28%	Oppose 12/16/11		
168	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-010-1	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.61% Approval: 26.61%	Oppose 12/16/11		
169	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-011-1	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.61% Approval: 29.88%	Oppose 12/16/11		
170	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Implementation	Initial Ballot	12/16/2011	1/6/2011	Quorum: 92.15% Approval: 42.06%	Oppose 12/16/11		
171	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Definitions	Initial Ballot	12/16/2011	1/6/2011	Quorum: 92.56% Approval: 25.34%	Oppose 12/16/11		
172	Project 2010-10	Project 2010-10: FAC Order 729_in	Initial Ballot	12/30/2010	1/8/2011	Quorum: 83.23% Approval: 58.16%			
173	Project 2010-10	Project 2010-10: FAC Order 729_rc	Recirculation Ballot	1/14/2011	1/23/2011	Quorum: 86.65% Approval: 68.98%			
174	Project 2010-11	Project 2010-11 TPL Table 1 Footnote B SAR_rc	Recirculation Ballot	1/26/2011	2/5/2011	Quorum: 93.29% Approval: 86.79%	Support 1/5/11		
175	Project 2010-13	Project 2010-13 - Relay Loadability Order - PRC-023	Successive Ballot	1/24/2011	2/14/2011	Quorum: 83.95% Approval: 65.71%	Support 2/11/11		
176	Project 2007-23	Project 2007-23 - Violation Severity Levels	Non-binding Poll	2/9/2011	2/22/2011	Quorum: 78.00% Approval: 72.00%	Support 10/28/10		
177	Project 2007-07	Project 2007-07 Vegetation Management: FAC-003-2	Successive Ballot	2/18/2011	2/28/2011	Quorum: 79.28% Approval: 79.34%	Support 2/22/11		
178	Project 2010-13	Project 2010-13 - Relay Loadability Order - PRC-023	Recirculation Ballot	2/24/2011	3/6/2011	Quorum: 87.35% Approval: 68.83%	Support 2/11/11		
179	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001, COM-002, IRO-001, and IRO-014	Initial Ballot	2/25/2011	3/7/2011	Quorum: 87.10% Approval: 49.54%	Support 3/2/11		
180	Project 2010-15	Project 2010-15 - Expedited Action Revisions to CIP-005-4	Successive Ballot	4/19/2011	4/28/2011	Quorum: 79.66% Approval: 38.00%	Oppose 4/19/11		
181	Project 2009-06	Project 2009-06 - Facility Ratings: FAC-008-3	Initial Ballot	4/21/2011	5/2/2011	Quorum: 86.01% Approval: 48.74%	Abstain 4/26/11		
182	Project 2009-06	Project 2009-06 - Facility Ratings: FAC-008-3	Non-binding Poll	4/21/2011	5/2/2011	Quorum: 75.58% Approval: 73.00%			
183	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing: PRC-005	Successive Ballot	5/3/2011	5/12/2011	Quorum: 78.33% Approval: 67.00%	No Recommendation		
184	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing: PRC-005	Non-binding Poll	5/3/2011	5/12/2011	Quorum: 75.00% Approval: 66.00%			
185	Project 2009-06	Project 2009-06 - Facility Ratings: FAC-008-3	Recirculation Ballot	5/12/2011	5/23/2011	Quorum: 91.25% Approval: 78.92%	Support 5/12/11		
186	Project 2006-02	Project 2006-02 - Assess Transmission and Future Needs - TPL-001 through TPL-006	Successive Ballot	5/18/2011	5/31/2011	Quorum: 92.07% Approval: 73.99%			
187	Project 2006-02	Project 2006-02 - Assess Transmission and Future Needs - TPL-001 through TPL-006	Non-binding Poll	5/18/2011	5/31/2011	Quorum: 86.79% Approval: 71.9%			
188	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-001-2, TOP-002-2 and TOP-003-2	Initial Ballot	5/31/2011	6/9/2011	Quorum: 88.47% Approval: 48.64%	Oppose 5/31/11		
189	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-001-2, TOP-002-2 and TOP-003-2	Non-binding Poll	5/31/2011	6/9/2011	Quorum: 84.18% Approval: 41.00%			
190	Project 2007-17	Project 2007-17 – Protection System Maintenance and Testing – PRC-005	Recirculation Ballot	6/20/2011	6/30/2011	Quorum: 82.97% Approval: 64.76%	Support 6/28/11		
191	Project 2007-17	Project 2007-17 – Protection System Maintenance and Testing – PRC-005	Non-binding Poll	6/20/2011	6/30/2011	Quorum: 52.63% Approval: 60.00%			
192	Project 2006-02	Project 2006-02 - Assess Transmission and Future Needs	Recirculation Ballot	7/13/2011	7/22/2011	Quorum: 94.33% Approval: 75.37%			
193	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-002-3	Recirculation Ballot	7/15/2011	7/25/2011	Quorum: 94.13% Approval: 76.99%	Support 7/22/11		
194	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-005-4	Recirculation Ballot	7/15/2011	7/25/2011	Quorum: 94.13% Approval: 75.17%	Support 7/22/11		
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]		
251	Project 2007-09	Project 2007-09 Generator Verification: MOD-027-1	Initial Ballot	4/6/2012	4/16/2012	Quorum: 88.04% Approval: 36.84%	Oppose 4/16/12		
252	Project 2007-09	Project 2007-09 Generator Verification: PRC-019-1	Initial Ballot	4/6/2012	4/16/2012	Quorum: 88.04% Approval: 48.70%%	Oppose 4/16/12		
253	Project 2007-09	Project 2007-09 Generator Verification: MOD-025-2	Non-binding Poll	4/6/2012	4/16/2012	Quorum: 86.82% Approval: 43.72%			
254	Project 2007-09	Project 2007-09 Generator Verification: MOD-027-1	Non-binding Poll	4/6/2012	4/16/2012	Quorum: 86.04% Approval: 38.56%			
255	Project 2007-09	Project 2007-09 Generator Verification: PRC-019-1	Non-binding Poll	4/6/2012	4/16/2012	Quorum: 86.53% Approval: 46.38%			
256	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: PRC-005-1.1a	Initial Ballot	4/6/2012	4/16/2012	Quorum: 88.95% Approval: 92.41%	Support 4/16/12		
257	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-001-2	Successive Ballot	4/11/2012	4/20/2012	Quorum: 78.28%% Approval: 75.44%			
258	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-002-3	Successive Ballot	4/11/2012	4/20/2012	Quorum: 78.02% Approval: 87.22%			
259	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-003-2	Successive Ballot	4/11/2012	4/20/2012	Quorum: 78.28% Approval: 80.11%			
260	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-001-2	Non-binding Poll	4/11/2012	4/23/2012	Quorum: 77.21% Approval: 69.84%			
261	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-003-2	Non-binding Poll	4/11/2012	4/23/2012	Quorum: 77.48% Approval: 67.64%			
262	Project 2009-26	Project 2009-26 - Interpretation of CIP-004-1 by WECC	Recirculation Ballot	4/20/2012	4/30/2012	Quorum: 90.96% Approval: 80.08%	Support 3/16/12		
263	Project 2010-INT-05	Interpretation 2010-INT-05 - Interpretation of CIP-002-1 R3 for Duke Energy	Recirculation Ballot	4/20/2012	4/30/2012	Quorum: 92.68% Approval: 94.61%	Support 3/16/12		
264	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-003-3	Recirculation Ballot	4/24/2012	5/3/2012	Quorum: 81.72% Approval: 87.34%			
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%			
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible] Approval: 68.22%	[illegible] 6/26/12		
289	Project 2007-06	Project 2007-06 - System Protection Coordination: PRC-027-1	Initial Ballot	6/26/2012	7/5/2012	Quorum: 84.24% Approval: 23.82%	Oppose 6/27/12		
290	Project 2007-06	Project 2007-06 - System Protection Coordination: PRC-027-1	Non-binding Poll	6/26/2012	7/5/2012	Quorum: 82.26% Approval: 25.19%			
291	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-002-3	Recirculation Ballot	6/27/2012	7/6/2012	Quorum: 85.34% Approval: 81.71%			
292	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-001-3	Recirculation Ballot	6/27/2012	7/6/2012	Quorum: 85.04% Approval: 81.72%			
293	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-002-3	Non-binding Poll	6/27/2012	7/6/2012	Quorum: 84.16% Approval: 79.16%			
294	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-001-3	Non-binding Poll	6/27/2012	7/6/2012	Quorum: 83.87% Approval: 86.91%			
295	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001-2	Successive Ballot	6/27/2012	7/9/2012	Quorum: 75.37% Approval: 72.16%	No Consensus 7/5/12		
296	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001-2	Non-binding Poll	6/27/2012	7/11/2012	Quorum: 75.37% Approval: 73.71%			
297	Project 2011-INT-02	Project 2011-INT-02 - Rapid Revision of VAR-002 for Constellation	Recirculation Ballot	7/18/2012	7/27/2012	Quorum: 90.97% Approval: 69.81%	Support 6/26/12		
298	Project 2011-INT-02	Project 2011-INT-02 - Rapid Revision of VAR-002 for Constellation	Non-binding Poll	7/18/2012	7/27/2012	Quorum: 81.31% Approval: 60.93%			
299	Project 2010-INT-01	Project 2010-INT-01 - Rapid Revision of TOP-006 for FMPP	Initial Ballot	7/20/2012	7/30/2012	Quorum: 80.39% Approval: 79.28%	Oppose 7/20/12		
300	Project 2010-INT-01	Project 2010-INT-01 - Rapid Revision of TOP-006 for FMPP	Non-binding Poll	7/20/2012	7/30/2012	Quorum: 78.26% Approval: 76.07%			
301	Project 2012-08.1	Project 2012-08.1 - Phase 1 of Glossary Updates: Statutory Definitions	Initial Ballot	7/24/2012	8/2/2012	Quorum: 83.11% Approval: 54.16%	Oppose 7/20/12		
302	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005	Successive Ballot	8/17/2012	8/27/2012	Quorum: 78.11% Approval: 80.31%	Support 6/22/12		
303	Project 2009-19	Project 2009-19 – Interpretation of BAL-002 by NWPP Reserve Sharing Group	Successive Ballot	8/23/2012	9/4/2012	Quorum: 79.21% Approval: 87.78%	Support 2/22/10		
304	Project 2010-05.1	Project 2010-05.1 –Protection Systems: Phase 1 (Misoperations): PRC-004-3	Initial Ballot	8/29/2012	9/7/2012	Quorum: 86.71% Approval: 37.68%	Support 9/5/12		
305	Project 2010-05.1	Project 2010-05.1 –Protection Systems: Phase 1 (Misoperations): PRC-004-3	Non-binding Poll	8/29/2012	9/7/2012	Quorum: 84.17% Approval: 37.36%			
306	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001-2	Recirculation Ballot	9/6/2012	9/17/2012	Quorum: 80.35% Approval: 75.01%			
307	Project 2007-02	Project 2007-02 - Operating Personnel Communication Protocols	Successive Ballot	9/11/2012	9/20/2012	Quorum: 77.70% Approval: 50.57%	Support 9/15/12		
308	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Non-binding Poll	9/11/2012	9/20/2012	Quorum: 84.05% Approval: 54.07%			
309	Project 2010-INT-01	Project 2010-INT-01 - Rapid Revision of TOP-006 for FMPP	Recirculation Ballot	9/12/2012	9/21/2012	Quorum: 85.36% Approval: 87.34%			
310	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Successive Ballot	9/18/2012	9/27/2012	Quorum: 78.54% Approval: 63.40%	No Consensus 9/27/12		
311	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Non-binding Poll	9/18/2012	9/27/2012	Quorum: 78.93% Approval: 71.04%			
312	Project 2009-19	Project 2009-19 - Interpretation of BAL-002-0 NWPP Reserve Sharing Group	Recirculation Ballot	9/28/2012	10/8/2012	Quorum: 85.11% Approval: 90.34%	Support 2/22/10		
313	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-002-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 74.85%	Support 10/4/12		
314	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-003-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.37% Approval: 89.50%	Support 10/4/12		
315	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-004-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 85.58%	Support 10/4/12		
316	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-005-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 89.46%	Support 10/4/12		
317	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-006-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 92.11%	Support 10/4/12		
318	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-007-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 87.73%	Support 10/4/12		
319	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-008-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 91.74%	Support 10/4/12		
320	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-009-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 91.73%	Support 10/4/12		
321	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-010-1	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 84.60%	Support 10/4/12		
322	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-011-1	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 92.90%	Support 10/4/12		
323	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Implementation	Successive Ballot	10/1/2012	10/10/2012	Quorum: 78.93% Approval: 94.00%	Support 10/4/12		
324	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Definitions	Successive Ballot	10/1/2012	10/10/2012	Quorum: 79.13% Approval: 91.59%	Support 10/4/12		
325	SPM-SPIG	Standard Processes Manual Revisions to Implement SPIG Recommendations	Initial Ballot	10/3/2012	10/12/2012	Quorum: 87.50% Approval: 63.25%	Support 10/4/12		
326	VRFs and VSLs	Revisions to Outstanding VRFs and VSLs	Non-binding Poll	10/10/2012	10/23/2012	Quorum: 78.57% Approval: 73.02%			
327	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005	Recirculation Ballot	10/15/2012	10/24/2012	Quorum: 81.08% Approval: 80.51%	Support 6/22/12		
328	Project 2007-09	Project 2007-09 Generator Verification: MOD-026-1	Successive Ballot	10/19/2012	10/31/2012	Quorum: 75.55% Approval: 76.50%			
329	Project 2007-09	Project 2007-09 Generator Verification: PRC-024-1	Successive Ballot	10/19/2012	10/31/2012	Quorum: 75.00% Approval: 57.24%			
330	Project 2007-09	Project 2007-09 Generator Verification: MOD-025-2	Successive Ballot	10/19/2012	10/31/2012	Quorum: 83.61% Approval: 68.31%			
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%			

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
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: 85.34% Approval: 71.39%			
351	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Non-binding Poll	10/24/2012	11/5/2012	Quorum: 78.93% Approval: 71.04%			
352	Project 2007-12	Project 2007-12 - Frequency Response: BAL-003-1	Successive Ballot	10/26/2012	11/6/2012	Quorum: 82.04% Approval: 76.08%	Support 11/5/12		
353	Project 2010-11	Project 2010-11 TPL footnote b Initial Ballot October 2012 in	Initial Ballot	11/9/2012	11/19/2012	Quorum: 80.45% Approval: 56.18%			
354	Project 2012-INT-02	Interpretation 2012-INT-02 - Interpretation of TPL-003-0a and TPL-004-0 for SPCS	Initial Ballot	11/26/2012	12/5/2012	Quorum: 84.81% Approval: 72.57%	Oppose 12/5/12		
355	Project 2013-02	Project 2013-02 - Paragraph 81	Initial Ballot	11/30/2012	12/10/2012	Quorum: 75.77% Approval: 96.45%	Support 12/10/12		
356	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Successive Ballot	12/4/2012	12/13/2012	Quorum: 76.78% Approval: 53.57%	No Consensus 12/13/12		
357	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Non-binding Poll	12/4/2012	12/13/2012	Quorum: 77.22% Approval: 57.91%			
358	Project 2007-06	Project 2007-06 - System Protection Coordination: PRC-027-1	Successive Ballot	12/7/2012	12/17/2012	Quorum: 76.47% Approval: 33.23%	Oppose 12/17/12		
359	Project 2007-06	Project 2007-06 - System Protection Coordination: PRC-027-1	Non-binding Poll	12/7/2012	12/17/2012	Quorum: 75.58% Approval: 34.80%			
360	Project 2012-INT-05	Interpretation 2012-INT-05: CIP-002-3 for OGE	Initial Ballot	12/11/2012	12/20/2012	Quorum: 84.50% Approval: 95.60%	Support 12/19/12		
361	SPM-SPIG	Standard Processes Manual Revisions to Implement SPIG Recommendations	Successive Ballot	12/11/2012	12/20/2012	Quorum: 83.24% Approval: 84.48%	Support 12/19/12		
362	Project 2007-09	Project 2007-09 Generator Verification: MOD-025-2	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 86.89% Approval: 73.06%			
363	Project 2007-09	Project 2007-09 Generator Verification: MOD-026-1	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 79.00% Approval: 79.36%			
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		
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: %			
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.
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		
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%			

Line	Project		Ballot Type	Start Date	End Date	Ballot Results	Recommendation / Date		Comments
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
492	Project 2014-03	Project 2014-03 - Revisions to TOP/IRO Reliability Standards	Additional Ballot	9/10/2014	9/19/2014	[illegible] /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%	[illegible] 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.[illegible] Approval: 93.21%/68.09%/74.25%/79.91%/85.68%/89.01%/91.79%/81.34%/96.63%/96.63%/95.52%/85.93%/98.13%	CIP-003-6 no consensus CIP-010-2 no consensus New Definitions-Affirmative Updated Definitions-Affirmative Implementation Plan-Affirmative Version X Materials-Affirmative Non-binding polls-Affirmative	CIP-003-6 and CIP-010-2 Affirmative	
500	Project 2009-03	Project 2009-03 Emergency Operations	Additional Ballot	10/10/2014	10/20/2014	Quorum: 80.93% Approval: 70.41%	Affirmative--10/17/14		
501	Project 2014-03	2014-03 - Revisions to TOP and IRO Standards (IRO-001-4, IRO-002-4, IRO-010-2, two Definitions, and Implementation Plan)	Final Ballot	10/10/2014	10/20/2014	Quorum: 90/77%/89.97%/89.97%/88.39%/88.39% Approval: 82.64%/85.96%/86.22%/94.07%/91.84%	Affirmative--10/17/14		
502	Project 2014-03	2014-03 - Revisions to TOP and IRO Standards (TOP-002-4, TOP-003-3, IRO-008-2, IRO-014-3, and IRO-017-1)	Final Ballot	10/10/2014	10/20/2014	Quorum: 89.71%/88.39%/89.71%/89.71%/89.97% 84.76%/86.55%/83.73%/89.88%/82.58%	Affirmative--10/17/14		
503	Project 2007-11	Project 2007-11 Disturbance Monitoring	Additional Ballot	10/10/2014	10/21/2014	Quorum: 77..69% Approval: 71.38%	Affirmative--10/17/14		
504	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Additional Ballot	10/10/2014	10/22/2014	Quorum: 85.13%/83.29% Approval: 94.75%/93.98%	Affirmative--10/20/14		
505	Project 2014-03	Project 2007-17.3 (PRC-005-X) Protection System Maintenance and Testing - Phase 3 (Sudden Pressure Relays)	Final Ballot	10/20/2014	10/29/2014	Quorum: 88.25% Approval: 74.14%	Affirmative--10/28/14		
506	Project 2014-03	Project 2008-02 Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS)	Final Ballot	10/28/2014	11/6/2014	Quorum: 87.53% Approval: 83.12%	Affirmative--10/31/14		
507	Project 2007-11	Project 2007-11 Disturbance Monitoring	Final Ballot	10/28/2014	11/6/2014	Quorum: 81.89% Approval: 68.51%	Affirmative--10/31/14		
508	Project 2007-11	Project 2010-05.2 Phase 2 of Special Protection Systems	Final Ballot	10/28/2014	11/6/2014	Quorum: 85.41% Approval: 73.33%	Negative--10/14/14		
509	Project 2007-11	Project 2009-03 Emergency Operations	Final Ballot	10/28/2014	11/6/2014	Quorum: 87.19% Approval: 73.20%	Affirmative--10/17/14		
510	Project 2007-11	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Final Ballot	10/28/2014	11/6/2014	Quorum: 89.49%/87.66%/87.08% Approval: 92.91%/92.15%/95.62%	Affirmative--10/20/14		
511	Project 2014-03	Project 2014-02 Critical Infrastructure Protection Standards Version 5 Revisions	Final Ballot	10/28/2014	11/6/2014	Quorum: 87.56%/87.32%87.07%/87.56%/87.80%87.56%86.59% Approval: 83.84%/95.34%/86.00%/95.35%91.17%/83.88%/95.40%/92.76%	CIP-003-6 no consensus CIP-010-2 no consensus New Definitions-Affirmative Updated Definitions-Affirmative Implementation Plan-Affirmative Version X Materials-Affirmative Non-binding polls-Affirmative		
512	Project 2014-03	2014-03 - Revisions to TOP and IRO Standards	Additional Ballot	11/4/2014	11/10/2014	Quorum: 78.36% Approval: 60.21%	Affirmative--11/4/14		
513	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation	Additional Ballot	11/12/2014	11/21/2014	Quorum: 79.73% Approval: 77.29%	Affirmative--11/21/14		
514	Project 2014-03	Project 2010-13.3 Phase 3 of Relay Loadability: Stable Power Swings	Additional Ballot	11/14/2014	11/24/2014	Quorum: 79.83% Approval: 67.39%	Affirmative--10/1/14		
515	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation	Final Ballot	12/5/2014	12/16/2014	Quorum: 84.27% Approval: 78.05%	Affirmative--12/12/14		
516	Project 2014-03	Project 2010-13.3 Phase 3 of Relay Loadability: Stable Power Swings	Final Ballot	12/5/2014	12/16/2014	Quorum: 84.81% Approval: 68.08%	Affirmative--12/15/14		
517	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Initial Ballots	12/10/2014	12/23/2014	Quorum: 79.38%/79.72%/79.60% Approval: 92.69%/93.55%/93.67%	Affirmative--12/22/14		
518	Project 2014-03	2014-03 - Revisions to TOP and IRO Standards	Additional Ballot	12/19/2014	1/7/2015	Quorum: 80.47% Approval: 72.43%	Affirmative--1/6/15		
519	Project 2014-02	2014-02 - Critical Infrastructure Protection Standards Version 5 Revisions	Additional Ballot	12/30/2014	1/9/2015	Quorum: 81.22%/81.71%/81.46%/81.71%/81.71%/81.22%/81.71%/81.46% Approval: 81.92%/98.89%/98.86%/88.13%/98.89%/86.02%/89.63%/97.21%	CIP-003-7 Binding and non-binding polls-no consensus CIP-003-7 Definition-Affirmative CIP-010-7 Binding and non-binding polls- Affirmative CIP-010-7 Definition- Affirmative CIP-004-7 Binding and non-binding polls – Affirmative CIP-007-7 Binding and non-binding polls –Affirmative CIP-011-7 Binding and non-binding polls –Affirmative CIP Implementation Plan- Affirmative 1/8/2015		
520	Project 2014-03	2014-03 - Revisions to TOP and IRO Standards - TOP-001-3	Final Ballots	1/15/2015	1/21/2015	Quorum: 84.70% Approval: 72.69%	Affirmative--1/6/15		
521	Project 2014-01	2014-01 - Standards Applicability for Dispersed Generation Resources - PRC-005-5	Initial Ballots	1/12/2015	1/22/2015	Quorum: 77.93% Approval: 93.74%	Affirmative--1/22/15		
522	Project 2014-01	2014-01 - Standards Applicability for Dispersed Generation Resources - PRC-001-1.1(ii), PRC-019-2, and PRC-024-2	Final Ballots	1/13/2015	1/22/2015	Quorum: 89.27%/89.30%/89.52% Approval: 93.99%/94.03%/95.82%	Affirmative--1/22/15		
523	Project 2014-02	2014-02 - Critical Infrastructure Protection Standards Version 5 Revisions CIP-003-7, CIP-004-7, CIP-010-3, and CIP-011-3	Final Ballot	1/23/2015	2/2/2015	Quorum: 84.15%/84.39%/84.15%/84.39%/84.39%/83.90%/84.39%/83.66% Approval: 79.76%/98.94%/98.94%/86.76%/98.93%/84.07%/90.10%/97.32%	Affirmative--1/29/15		
524	Project 2014-01	2014-01 - Standards Applicability for Dispersed Generation Resources - PRC-005-5	Final Ballot	3/2/2015	3/11/2015	Quorum: 83.52% Approval: 98.03%	Affirmative--1/22/15		
525	Project 2010-14.1	Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves	Additional Ballot	3/6/2015	3/16/2015	Quorum: 77.29% Approval: 59.30%	Negative--3/13/2015		
526	Project 2008-02.2	Project 2008-02.2 Phase 2 of Undervoltage Load Shedding (UVLS): Misoperations	Initial Ballot	3/27/2015	4/7/2015	Quorum: 79.93% Approval: 84.31%	Affirmative--3/31/15		
527	Project 2014-04	Project 2014-04 Physical Security	Initial Ballot	3/31/2015	4/9/2015	Quorum: 88.33% Approval: 89.95%	Affirmative--3/31/15		
528	Project 2008-02.2	Project 2008-02.2 Phase 2 of Undervoltage Load Shedding (UVLS): Misoperations	Final Ballot	4/17/2015	4/27/2015	Quorum: 84.86% Approval: 89.63%	Affirmative--3/31/15		
529	Project 2014-04	Project 2014-04 Physical Security	Final Ballot	4/20/2015	4/29/2015	Quorum: 92.00% Approval: 92.35%	Affirmative--3/31/15		
530	Project 2007-06	Project 2007-06 System Protection Coordination	Additional Ballot	5/6/2015	5/15/2015	Quorum: 81.79% Approval: 39.63%	Negative--5//13/15		
531	Project 2015-06	2015-06 Interconnection Reliability Operations and Coordination	Initial Ballot	6/29/2015	7/8/2015	Quorum: 75.23%/84.00% Approval: 90.35%/97.50%	Affirmative--7/7/15		
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%	Affirmative--7/24/15		

Line	Project	Ballot	Ballot Type	Start Date	End Date	Ballot Results	Recommendation / Date		Comments
565	Project 2016-02	Project 2016-02 Modifications to CIP Standards	Additional Ballot	11/23/2016	12/5/2016	Quorum: 76.40%/76.63% Approval: 85.56%/75.54%	Affirmative--12/1/16		
566	Project 2015-08	Project 2015-08 Emergency Operations EOP-005-3 and EOP-006-3	Additional Ballot	11/30/2016	12/9/2016	Quorum: 80.71%/82.43% Approval: 76.93%/77.17%	Affirmative--11/30/16		
567	Project 2015-08	Project 2015-08 Emergency Operations EOP-008-2	Final Ballot	11/30/2016	12/9/2016	Quorum: 93.36% Approval: 93.17%	Affirmative--11/30/16		
568	Project 2016-01	Project 2016-01 Modifications to TOP and IRO Standards	Final Ballot	12/2/2016	12/12/2016	Quorum: 90.74%/90.40% Approval: 74.30%/72.52%	Affirmative--12/2/16		
569	Project 2016-02	Project 2016-02 Modifications to CIP Standards | CIP-003-7 and Implementation	Final Ballot	12/9/2016	12/19/2016	Quorum: 82.89%/83.14% Approval: 87.95%/83.03%	Affirmative--12/1/16		
570	Project 2015-08	Project 2015-08 Emergency Operations EOP-004-4	Additional Ballot	12/28/2016	1/6/2017	Quorum: 79.47% Approval: 93.55%	Affirmative--1/4/17		
571	Project 2015-08	Project 2015-08 Emergency Operations EOP-005-3, EOP-006-3	Final Ballot	12/28/2016	1/6/2017	Quorum: 91.00%/91.55% Approval: 83.65%/80.56%	Affirmative--1/4/17		
572	Project 2016-02	Project 2016-02 Modifications to CIP Standards | CIP-003-7(i) Implementation Plan and 2 Definitions	Initial Ballot	1/16/2017	1/25/2017	Quorum: 77.81%/76.71%/77.26%/76.71% Approval: 81.30%/87.87%/86.75%/86.47%	Affirmative--1/23/17		
573	Project 2016-03	Project 2016-03 Cyber Security Supply Chain Risk Management	Initial Ballot	2/24/2017	3/6/2017	Quorum: 87.13% Approval: 10.36%	Abstain--3/2/17		
574	Project 2015-08	Project 2015-08 Emergency Operations EOP-004-4	Final Ballot	1/24/2017	2/2/2017	Quorum: 84.46% Approval: 93.80%	Affirmative--1/4/17		
575	Project 2016-02	Project 2016-02 Modifications to CIP Standards | CIP-003-7(i) Implementation Plan and 2 Definitions	Final Ballot	1/30/2017	2/8/2017	Quorum: 86.58%/85.48%/86.03%/85.48% Approval: 78.55%/86.00%/85.81%/85.54%	Affirmative--1/23/17		
576	SPM	Revisions to the NERC Standards Process Manual	Initial Ballot	4/24/2017	5/3/2017	Quorum: 78.21% Approval: 64.72%			
577	Project 2016-03	Project 2016-03 Cyber Security Supply Chain Risk Management	Additional Ballot	6/6/2017	6/15/2017	Quorum: 76.02%/76.02%/77.21% Approval: 89.84%/82.92%/88.64%	Affirmative--6/8/17		
578	Project 2016-03	Project 2016-03 Cyber Security Supply Chain Risk Management	Final Ballot	7/11/2017	7/20/2017	Quorum: 81.59%/81.33%/82.84% Approval: 88.79%/81.40%/84.19%	Affirmative--6/8/17		
579	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation TPL-007-2	Initial Ballot	8/2/2017	8/11/2017	Quorum: 79.87% Approval: 72.67%	Affirmative--8/3/17		
580	Project 2016-04	Project 2016-04 Modifications to PRC-025-1	Initial Ballot	8/29/2017	9/8/2017	Quorum: 80.45% Approval: 78.79%	Affirmative--9/1/17		
581	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-012-1 Control Center Communication Networks	Initial Ballot	8/14/2017	9/12/2017	Quorum: 80.00% Approval: 42.74%	Affirmative--9/1/17		
582	Project 2015-10	Project 2015-10 Single Points of Failure TPL-001	Initial Ballot	9/8/2017	10/23/2017	Quorum: 82.71% Approval: 30.50%	Abstain--10/18/17		
583	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation TPL-007-2	Final Ballot	10/20/2017	10/30/2017	Quorum: 88.74% Approval: 73.35%	Affirmative--8/3/17		
584	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-002-6	Initial Ballot	9/14/2017	10/30/2017	Quorum: 85.40% Approval: 66.78%	Affirmative--10/30/17		
585	Project 2015-09	Project 2015-09 Establish and Communicate System Operating Limits	Initial Ballot	11/3/2017	11/13/2017	Quorum: 87.01%/86.90%/86.90%/85.57%/85.85 Approval: 58.12%/63.17%/56.55%/76.40%/68.59%	Affirmative--11/10/17		
586	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-012-1	Additional Ballot	11/20/2017	12/11/2017	Quorum:77.10% Approval: 63.91%	Affirmative--12/4/17		
587	Project 2016-04	Project 2016-04 Modifications to PRC-025-1	Additional Ballot	10/30/2017	12/13/2017	Quorum: 81.73% Approval: 88.25%	Affirmative--12/4/17		
588	Project 2016-04	Project 2016-04 Modifications to PRC-025-1	Final Ballot	1/9/2018	1/18/2018	Quorum: 82.69% Approval: 89.46%	Affirmative--12/4/17		
589	Project 2017-02	Project 2017-02 Modifications to Personnel Performance, Training and Qualifications	Initial Ballot	2/26/2018	3/7/2018	Quorum: 80.93%/81.27% Approval: 97.50%/98.91%	Affirmative--3/2/18		
590	Project 2017-02	Project 2017-02 Modifications to Personnel Performance, Training and Qualifications	Final Ballot	4/3/2018	4/12/2018	Quorum: 84.82%/84.86% Approval: 96.64%/97.88%	Affirmative--3/2/18		
591	Project 2015-10	Project 2015-10 Single Points of Failure TPL-001	Additional Ballot	2/23/2018	4/23/2018	Quorum: 80% Approval: 26.44%	Affirmative--4/16/18		
592	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-002-6	Additional Ballot	3/16/2018	4/30/2018	Quorum: 79.50% Approval: 93.31%	Affirmative--4/25/18		
593	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-012-1	Additional Ballot	3/16/2018	4/30/2018	Quorum:78.06% Approval: 83.71%	Affirmative--4/25/18		
594	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-012-1 Control Center Definition and Implementation Plan	Initial Ballot	3/16/2018	4/30/2018	Quorum: 81.33%/81.54% Approval: 46.71%/37.98%	Negative--4/25/18		
595	Project 2017-06	Project 2017-06 Modifications to BAL-002-2	Initial Ballot	4/27/2018	5/8/2018	Quorum: 81.82% Approval: 80%	Abstain--5/7/17		
596	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-012-1	Additional Ballot	5/18/2018	7/3/2018	Quorum: 75.16% Approval: 68.45%	Affirmative--6/29/18		
597	Project 2017-06	Project 2017-06 Modifications to BAL-002-2	Final Ballot	7/5/2018	7/16/2018	Quorum: 84.42% Approval: 71.85%	Abstain--5/7/17		
598	SPM	Revisions to the NERC Standards Process Manual	Additional Ballot	7/31/2018	8/9/2018	Quorum: 80.34% Approval: 81.95%	Affirmative--8/7/18		
599	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-012-1	Final Ballot	8/3/2018	8/13/2018	Quorum:81.55% Approval: 72..55%	Affirmative--4/25/18		
600	Project 2015-10	Project 2015-10 Single Points of Failure TPL-001	Additional Ballot	9/5/2018	9/14/2018	Quorum: 75.59% Approval: 69.07%	Affirmative--9/5/18		
601	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-002-6	Initial Ballot	9/28/2018	10/9/2018	Quorum: 78.59% Approval: 55.89%	Affirmative--10/5/18		
602	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-003-8	Initial Ballot	9/28/2018	10/9/2018	Quorum: 78.77% Approval: 90.06%	Affirmative--10/5/18		
603	Project 2015-09	Project 2015-09 Establish and Communicate System Operating Limits	Additional Ballot	10/8/2018	10/17/2018	Quorum: 83.65%/84.08%/83.77%/84.82%/82.43%/82.11%/84.08%/83.60%/83.12%/80.98%/83.28% Approval: 67.65%/67.46%/53.22%/77.07%/59.02%/59.79%/75.07%/69.27%/71.98%/69.93%/82.26%	Affirmative--10/12/18		
604	Project 2018-02	Project 2018-02 Modifications to CIP-008 Cyber Security Incident Reporting	Initial Ballot	10/18/2018	10/22/2018	Quorum: 81.17% Approval: 20.02%	Reject--10/22/18		
605	Project 2015-10	Project 2015-10 Single Points of Failure TPL-001	Final Ballot	10/11/2018	10/22/2018	Quorum: 86.39% Approval: 66.69%	Affirmative--9/5/18		
606	SPM	Revisions to the NERC Standards Process Manual	Final Ballot	10/7/2018	10/29/2018	Quorum: 85.96% Approval: 81.61%	Affirmative--8/7/18		
607	Project 2018-01	Project 2018-01 Canadian-specific Revisions to TPL-007-2	Initial Ballot	11/6/2018	11/15/2018	Quorum: 77.54%/79.10% Approval: 100%/100%	Affirmative--11/6/18		
608	Project 2018-02	Project 2018-02 Modifications to CIP-008 Cyber Security Incident Reporting	Additional Ballot	11/20/2018	11/29/2018	Quorum: 94.44% Approval: 75.54%	Affirmative--11/20/18		
609	Project 2018-01	Project 2018-01 Canadian-specific Revisions to TPL-007-2	Final Ballot	11/29/2018	12/10/2018	Quorum: 80.43%/82.09% Approval: 100%/100%	Affirmative--11/6/18		
610	Project 2017-01	Project 2017-01 Modifications to BAL-003-1.1	Initial Ballot	1/8/2019	1/17/2019	Quorum: 92.02%/91% Approval: 96.41%/99.04%	Affirmative--1/14/19		
611	Project 2018-02	Project 2018-02 Modifications to CIP-008 Cyber Security Incident Reporting	Final Ballot	1/15/2019	1/22/2019	Quorum: 96.30% Approval: 77.89%	Affirmative--11/20/18		
612	Project 2018-03	Project 2018-03 Standards Efficiency Review Retirements	Initial Ballot	4/3/2019	4/12/2019	Quorum: 86.75%/87.96%/87.80%/87.58%/87.58%/87.50%/87.58%/87.34%/87.46%/86.45%/87.34%/86.77%/87.17%/87.17%/86.89%/85.71%/85.67%/86.39% 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%/97.75%/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		

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
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		
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%/99.6%/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%/89.54% Approval: 38.87%/48.30%/51.17%/26.30%/42.81%/42.32%/52.87%/53.26%/32.43%/47.25%/51.23%	Abstain--3/17/21		
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%/87.83%/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		
647	Project 2016-02	Project 2016-02 Modifications to CIP Standards Virtualization	Additional Ballot	4/1/2022	4/12/2022	Quorum: 81.05%/81.05%/81.25%/81.25%/81.25%/81.25%/81.25%/80.92%/80.92%/80.92%/81.25% Approval: 72.90%/73.43%/77.03%/60.83%/76.13%/61.45%/78.67%/78.42%/56.81%/79.08%/78.67%	Abstain--4/7/22		
648	Project 2020-03	Project 2020-03 Supply Chain Low Impact Revisions	Additional Ballot	2/25/2022	4/15/2022	Quorum: 81.51%/82.01% Approval: 52.81%/49.72%	Abstain--4/7/22		
649	Project 2020-05	Project 2020-05 Modifications to FAC-001 and FAC-002	Final Ballot	4/13/2022	4/22/2022	Quorum: 94.86%/94.84% Approval: 85.64%/88.29%	Affirmative--1/31/22		
650	Project 2021-07	Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination	Initial Ballot	6/8/2022	6/21/2022	Quorum: 94.27%/94.59% Approval: 21.94%/69.66%	Abstain--6/14/22		
651	Project 2020-06	Project 2020-06 Verifications of Models and Data for Generators	Initial Ballot	6/27/2022	7/6/2022	Quorum: 87.78%/88.06% Approval: 27.85%/28.51%	Abstain--6/29/22		
652	Project 2021-04	Project 2021-04 Modifications to PRC-002	Initial Ballot	7/15/2022	7/25/2022	Quorum: 86.94%/87.85% Approval: 66.90%/75.89%	Abstain--7/22/22		

RSC Meeting #22-5, Agenda Item 4.3: Comment History

(As of 12/2/2022)

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

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
12.	Project 2009-02	Project 2009-02 - Real-time Reliability Monitoring and Analysis Capabilities	Concept White Paper		2/16/11	4/4/11	Yes 4/4/11
13.	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface	Various BAL, CIP, EOP, FAC, IRO, MOD, PER, PRC, TOP, and VAR Standards		3/4/11	4/4/11	Yes 4/4/11
14.	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting	EOP-004-2		3/9/11	4/8/11	Yes 4/8/11
15.	RFC RoP	Notice of Proposed Changes to RFC Rules of Procedure and Request for Comments			3/1/11	4/15/11	
16.	NERC RoP	Proposed Amendments to NERC Rules of Procedure Appendices 3B and 3D	Appendices 3B and 3D		3/1/11	4/15/11	Yes 4/15/11
17.	Project 2010-15	Project 2010-15 - Urgent Action Revisions to CIP-005-3 - CIP-005	CIP-005		3/29/11	4/28/11	Yes 4/27/11
18.	Project 2009-06	Project 2009-06 - Facility Ratings - FAC-008 and FAC-009	FAC-008-3		3/17/11	5/2/11	Yes 5/2/11
19.	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	PRC-005-2		4/13/11	5/12/11	Yes 5/9/11
20.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System	BES Definition		4/28/11	5/27/11	Yes 5/27/11
21.	Project 2006-02	Project 2006-02 - Assess Transmission and Future Needs	TPL-001-2		4/18/11	5/31/11	Yes 5/31/11
22.	Project 2007-03	Project 2007-03 - Real-time Operations - TOP-001 through TOP-008 and PER-001	TOP-001 through TOP-008 and PER-001		4/26/11	6/9/11	Yes 6/9/11
23.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System	BES Definition		5/11/11	6/10/11	Yes 6/10/11

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
24.	NERC RoP	Rules of Procedure Development Team: BES Definition Exception Process	BES Definition Exception Process		5/11/11	6/10/11	Yes 6/10/11
25.	N/A	CAN-0024--Draft CAN-0024 CIP-002 through CIP-009 Routable Protocols and Data Diodes	CAN-0024 CIP-002 through CIP-009		5/20/11	6/10/11	
26.	N/A	CAN-0029--Draft CAN-0029 PRC-004-1 R1, R2 and R3 Misoperations	CAN-0029 PRC-004-1 R1, R2 and R3		5/20/11	6/10/11	
27.	N/A	CAN-0030--Draft CAN-0030 Attestations	CAN-0030 Attestations		5/20/11	6/10/11	
28.	N/A	CAN-0039--Draft CAN-0039 DOE Form 407	CAN-0039 DOE Form 407		5/20/11	6/10/11	
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

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
33.	NERC RoP	Proposed Changes to NERC Rules of Procedure and associated Appendices (Appendix 4B – Sanction Guidelines; and Appendix 4C – Compliance Monitoring and Enforcement Program)	Appendices 4B and 4C		6/30/11	8/15/11	
34.	N/A	Compliance Application Notice (CAN) Process	CAN Process		8/15/11	9/6/11	Yes 9/6/11
35..	N/A	CAN-0016 CIP-001 R1 - Sabotage Reporting Procedure	CAN-0016 CIP-001, R1		8/15/11	9/6/11	Yes 9/6/11
36.	N/A	DRAFT CANs Posted for Comment and Retirement of CAN-0001 through 0004	CAN-0001 through 0004 Retirement		8/31/11	9/21/11	
37.	NERC RSDP	NERC 2012-2014 Reliability Standards Development Plan	2012-2014 RSDP		9/12/11	9/26/11	Yes 9/26/11
38.	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	PRC-005-2		8/15/11	9/28/11	Yes 9/28/11
39.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System - Initial Ballot of Definition of BES	BES Definition		8/26/11	10/10/11	Yes 10/10/11
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

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42.	RoP	Proposed Changes to NERC Rules of Procedure and All Appendices			9/2/11	10/17/11	
43.	Project 2010-17	Project 2010-17 - Bulk Electric System (BES) Definition - Rules of procedure Modifications to Support BES Exception Requests	RoP Section 509, Section 1703 and Appendix 5C		9/13/11	10/27/11	Yes 10/27/11
44.	N/A	CAN-0010--Definition of "Annual" and Implementation of Annual Requirements	CAN-0010 Definition of Annual		10/10/11	10/31/11	Yes 10/31/11
45.	N/A	CAN-0011--PRC-005-1 R2: New Equipment	CAN-0011 PRC-005-1 R2		10/10/11	10/31/11	Yes 10/31/11
46.	N/A	CAN-0012--Completion of Periodic Activity Requirements During Implementation Plan	CAN-0012 Completion of Periodic Activity Requirements		10/10/11	10/31/11	Yes 10/31/11
47	N/A	CAN-0013--PRC-023 R1 and R2 Effective Dates for Switch-on-to-Fault Schemes	CAN-0013 PRC-023 R1 and R2		10/10/11	10/31/11	
48.	N/A	CAN-0015--Unavailability of NERC Software Tools	CAN-0015 NERC Tools		10/10/11	10/31/11	Yes 10/31/11
49.	N/A	CAN-0022--VAR-002-1.1b R1 and R3 Generator Operation in Manual Mode	CAN-0022 VAR-002-1.1b R1 and R3		10/10/11	10/31/11	
50.	N/A	CAN-0024--CIP-002 R3 Routable Protocols and Data Diode Devices	CAN-0024 CIP-002, R3		10/10/11	10/31/11	Yes 10/31/11
51.	N/A	CAN-0026--TOP-006 R3 Protection Relays	CAN-0026 TOP-006, R3		10/10/11	10/31/11	Yes 10/31/11
52.	N/A	CAN-0028--TOP-006-1 R1.2 Reporting Responsibilities	CAN-0028 TOP-006-1, R1.2		10/10/11	10/31/11	

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53.	N/A	CAN-0020--TPL-002, TPL-003, TPL-004 and TOP-002 Equipment Maintenance Outages	CAN-0020 TPL-002, TPL-003, TPL-004 and TOP-002		10/19/11	11/9/11	
54.	N/A	CAN-0030--Attestations	CAN-0030		10/19/11	11/9/11	
55.	Project 2011-INT-01	Project 2011-INT-01 - Interpretation of MOD-028 for Florida Power & Light Company	MOD-028, R3.1		10/3/11	11/16/11	Yes 11/16/11
56.	Project 2009-22	Project 2009-22 - Interpretation of COM-002-2 R2 by the IRC	Interpretation of COM-002-2, R2		10/4/11	11/18/11	Yes 11/18/11
57.	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface	Various BAL, CIP, EOP, FAC, IRO, MOD, PER, PRC, TOP, and VAR Standards		10/5/11	11/18/11	Yes 11/18/11
58.	N/A	Draft Directive Regarding Generator Transmission Leads	Draft Directive #2011 CAG-001		10/17/11	11/18/11	Yes 11/18/11
59.	Project 2008-10	Project 2008-10 - Interpretation of CIP-006-1 R1.1 by Progress Energy	Interpretation of CIP-006-1, R1.1		10/12/11	11/21/11	Yes 11/21/11
60.	N/A	CAN-0040 - BAL-003 Frequency Bias Calculation			11/2/11	11/23/11	
61.	N/A	CAN-0043 - PRC-005 Protection System Maintenance and Testing Evidence	PRC-005 Evidence		11/2/11	11/23/11	Yes 11/22/11
62.	Project 2007-12	Project 2007-12 - Frequency Response	BAL-003-1			12/8/11	Yes 12/8/11
63.	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting	EOP-004-2			12/12/11	Yes 12/12/11
64.	N/A	Draft CAN-0027: TOP-003 R2 Coordination of Scheduled Outages	CAN-0027 TOP-003, R2		11/22/11	12/14/11	
65.	NERC RoP	Proposed Changes to the NERC Rules of Procedure and Associated Appendices			11/7/11	12/22/11	

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66.	NERC RoP	Notice of Revisions to Proposed New Sections 1.1.24 and 5.11 of Appendix 4C of the NERC Rules of Procedure, as Originally Posted for Comment on November 7, 2011			11/22/11	12/22/11	
67.	Regional Standard	Regional Reliability Standard PRC-006-NPCC-1 — Automatic Underfrequency Load Shedding	PRC-006-NPCC-1		11/22/11	12/22/11	
68.	Project 2008-06	Project 2008-06 - Cyber Security - Order 706 - CIP-002-5 through CIP-009-5, CIP-010-1, and CIP-011-1 (Version 5 CIP Standards)	Version 5 CIP Standards		11/7/11	1/6/12	Yes 1/6/12
69.	Project 2007-03	Project 2007-03 - Real-time Transmission Operations - TOP-001-2, TOP-002-3 and TOP-003-2	TOP-001-2 TOP-002-3 TOP-003-2		12/14/11	1/12/12	Yes 1/12/12
70.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	BES Definition, Phase 2		1/4/12	2/3/12	Yes 2/3/12
71.	N/A	Order 754 - Request for Data or Information	Data Request		12/22/11	2/6/12	Yes 2/6/12
72.	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001, COM-002 and IRO-001-3	COM-001 COM-002 IRO-001-3		1/9/12	2/9/12	Yes 2/8/12
73.	WECC Regional Standard	Regional Reliability Standard BAL-004-WECC-02 - Automatic Time Error Correction	BAL-004-WECC-02		1/23/12	3/9/12	
74.	WECC Regional Standard	Regional Reliability Standard BAL-001-0.1a - Real Power Balancing Control Performance - WECC Variance	BAL-001-0.1a		1/23/12	3/9/12	

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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
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	

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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
88.	Project 2007-12	Project 2007-12 Frequency Response Technical Conferences			5/30/12	6/15/12	
89.	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-003	COM-003		5/7/12	6/20/12	Yes 6/20/12
90.	N/A	Adequate Level of Reliability Revised Definition and Associated Documents	Adequate Level of Reliability (ALR)		4/25/12	6/25/12	Yes 6/25/12
91.	N/A	Order 754 - Request for Data or Information	Data Request		5/11/12	6/25/12	Yes 6/25/12
92.	Project 2011-INT-02	Project 2011-INT-02 - Interpretation of VAR -002 for Constellation	Interpretation of VAR -002		5/22/12	6/27/12	Yes 6/27/12
93.	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	PRC-005-2		5/29/12	6/27/12	Yes 6/27/12
94.	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserve	BAL-001-1		6/4/12	7/3/12	Yes 7/3/12
			BAL-002-2		6/4/12	7/3/12	Yes 7/3/12
			BAL-012-1		6/4/12	7/3/12	Yes 7/3/12
			BAL-013-1		6/4/12	7/3/12	Yes 7/3/12
95.	Project 2007-06	Project 2007-06 - System Protection Coordination	PRC-001 and PRC-027		5/21/12	7/5/12	Yes 7/5/12
96.	N/A	Cost Effective Analysis Process (CEAP) for NERC ERO Standards	CEAP		5/7/12	7/6/12	Yes 7/6/12

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97.	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001, COM-002 and IRO-001-3	COM-001, COM-002 and IRO-001-3		6/7/12	7/6/12	Yes 7/6/12
98.	Project 2006-02	Project 2006-02 – Assess Transmission Future Needs and Develop Transmission Plans	TPL-002-1b, footnote 'b' and TPL-001-3, footnote 12		6/19/12	7/9/12	Yes 7/9/12
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

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107.	Project 2010-11	Project 2010-11 - TPL Table 1 Order TPL-002-1b, footnote 'b' and TPL-001-3, footnote 12	TPL-002-1b, footnote 'b' and TPL-001-3, footnote 12		7/31/12	8/29/12	Yes 8/29/12
108.	Project 2006-02	Project 2006-02 - Assess Transmission and Future Needs			7/31/12	8/30/12	
109.	Project 2009-19	Project 2009-19 – Interpretation of BAL-002 by NWPP Reserve Sharing Group			7/25/12	9/4/12	
110.	Project 2013-02	Project 2013-02 - Paragraph 81	Paragraph 81		8/3/12	9/4/12	Yes 9/4/12
111.	Project 2010-05.1	Project 2010-05.1 - Protection Systems: Phase 1 (Misoperations)			7/25/12	9/7/12	Yes 9/7/12
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

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120.		Revisions to Outstanding VRFs and VSLs			9/5/12	10/19/12	
121.	Project 2013-01	Project 2013-01 - Cold Weather Preparedness			9/25/12	10/24/12	
122.	Project 2007-09	Project 2007-09 - Generator Verification			9/28/12	10/29/12	
123.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System			10/4/12	11/5/12	
124.	2007-12	Project 2007-12 - Frequency Response			10/5/12	11/7/12	
125.	Project 2008-06	Project 2008-06 - Cyber Security - Order 706 - CIP-002-5 through CIP-009-5, CIP-010-1, and CIP-011-1	Version 5 CIP Standards		10/26/12	11/7/12	
126.	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-025	PRC-025		10/5/12	11/7/12	
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

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135.	Project 2012-INT-05	Project 2012-INT-05 - Interpretation of CIP-002-3 for OGE	Interpretation of CIP-002-3		11/6/12	12/20/12	Yes 12/20/12
136.	N/A	Standard Processes Manual to Implement SPIG Revisions	SPIG Reco		11/21/12	12/20/12	Yes 12/20/12
137.	Project 2010-11	Project 2010-11 - TPL Table 1, Footnote B	TPL-002-1b, footnote 'b' and TPL-001-3, footnote 12		12/10/12	1/11/13	Yes 1/11/13
138.	Project 2007-09	Project 2007-09 - Generator Verification - PRC-024-1	PRC-024-1		12/12/12	1/11/13	Yes 1/11/13
139.	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves - BAL-012-1	BAL-012-1		11/30/12	1/14/13	Yes 1/14/13
140.	N/A	Reliability Guideline--Draft Generating Unit Winter Weather Readiness - Current Industry Practices			12/20/12	2/4/13	Yes 2/4/13
141.	Project 2010-05-1	Project 2010-05-1 Protection System Misoperations					Yes 2/20/13
142.	Project 2007-09	Project 2007-09 Generator Verification - PRC-024-1	PRC-024-1	Formal	1/25/13	2/25/13	Yes 2/25/13
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

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147.	Project 2012-08-1	Project 2012-08-1 - Phase 1 of Glossary Updates--Statutory Definitions	Glossary of Terms	Formal	2/21/13	3/22/13	Yes 3/22/13
148.	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-003-1	COM-003-1	Formal	3/7/13	4/5/13	Yes 4/5/13
			RSAW	Feedback	3/7/13	4/5/13	Yes 4/5/13
149.	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves	BAL-001-2	Formal	3/12/13	4/25/13	Yes 4/25/13
			BAL-002-2	Formal	3/12/13	4/25/13	Yes 4/25/13
			BAL-013-1	Formal	3/12/13	4/25/13	Yes 4/25/13
150.	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Reclosing Relays)	Draft SAR	Informal	4/5/13	5/6/13	Yes 5/6/13
			PRC-005-3	Formal	4/5/13	5/6/13	Yes 5/613
151.	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation	PRC-023-3 PRC-025-1	Formal	4/25/13	5/24/13	Yes 5/24/13
152.	Project 2007-11	Project 2007-11 - Disturbance Monitoring — PRC-002 and PRC-018	SAR	Informal	5/03/13	6/03/13	Yes 6/3/13
153.	Project 2007-11	Project 2007-11 - Disturbance Monitoring PRC-002 and PRC-018	Request for Information	Informal	6/05/13	7/05/13	
154.	Project 2007-06	Project 2007-06 - System Protection Coordination - PRC-001 and PRC-027	PRC-001 and PRC-027		6/04/13	7/03/13	Yes 7/03/13
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

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159.	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-025	PRC-025-1		6/20/13	7/19/13	Yes 7/19/13
160.	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-023	PRC-023-3	Formal	6/20/13	8/05/13	Yes 8/5/13
161.	N/A	SPP RE Regional Standards Process Manual	SPP RSPM		6/26/13	8/09/13	
162.	Project 2013-03	Project 2013-03 - Geomagnetic Disturbance Mitigation	EOP-010-1	Formal	6/27/13	8/12/13	Yes 8/12/13
163.	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Reclosing Relays) - PRC-005	PRC-005-3	Formal	7/10/13	8/23/13	Yes 8/23/13
164.	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards	INT-004-3 INT-006-4 INT-009-2 INT-010-2 INT-011-1	Informal	7/25/13	8/23/13	Yes 8/23/13
165.	Project 2012-05	Project 2012-05 ATC Revisions (MOD A) - MOD-001-2	MOD-001-2	Formal	7/11/13	8/26/13	Yes 8/26/13
166.	Project 2010-01	Project 2010-01 - Training - PER-005-2	PER-005-2	Formal	7/19/13	9/03/13	Yes 9/3/13
167.	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4, VAR-002-3	VAR-001-4 VAR-002-3	Formal	7/19/13	9/03/13	Yes 9/3/13
168	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-032-1, MOD-033-1	MOD-032-1 MOD-033-1	Formal	7/22/13	9/04/13	Yes 9/4/13
169.	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	MOD-031-1	Formal	7/22/13	9/04/13	Yes 9/4/13
170	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System – Phase 2	BES Definition Phase 2	Formal	8/6/13	9/4/13	Yes 9/4/13
171	Project 2012-13	Project 2012-13 - NUC Five-Year Review	NUC-001-2	5-year review	7/26/13	9/9/13	Yes 9/9/13

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172	2014-2016 RSDP	2014-2016 Reliability Standards Development Plan	Reliability Standards Development Plan	Annual Review	8/30/13	9/13/13	Yes 9/13/13
173	Project 2010-02	Project 2010-02 Five-Year Review of FAC Standards	FAC-001-1 FAC-002-1	5-year review	8/1/13	9/16/13	Yes 9/16/13
174	Project 2010-02	Project 2010-02 Five-Year Review of FAC Standards	FAC-003-3 FAC-008-3 FAC-010-2.1 FAC-011-2 FAC-013-2 FAC-014-2	5-year review	8/1/13	9/16/13	Yes 9/16/13
175	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves - BAL-002-2, BAL-013-1	BAL-002-2	Formal	8/2/13	9/16/13	Yes 9/16/13
176	Project 2009-03	Project 2009-03 — Five-Year Review of Emergency Operations EOP-001, EOP-002, EOP-003, and IRO-001	EOP-001-2.1b EOP-002-3.1 EOP-003-2	5-year review	8/6/13	9/19/13	Yes 9/19/13
177	Project 2012-09	Project 2012-09 IRO Five-Year Review	IRO-003-2 IRO-004-2 IRO-005-4 IRO-006-5 IRO-006-East IRO-008-1 IRO-009-1 IRO-010-1a	5-year review	8/7/13	9/20/13	Yes 9/20/13
178	Project 2008-02	Project 2008-02 Undervoltage Load Shedding	Revised SAR	Informal	9/10/13	10/9/13	Yes 10/9/13
179	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation	EOP-010-1	Formal	9/4/13	10/18/13	Yes 10/18/13
180	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System	BES Definition	Formal	9/27/13	10/28/13	Yes 10/28/13
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

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184	Project 2012-05	Project 2012-05 ATC Revisions (MOD A)	MOD-001-2	Formal	10/4/13	11/20/13	Yes 11/18/13
185	Project 2010-03	Project 2010-03 Modeling Data (MOD B)	MOD-032-1, MOD-033-1	Formal	10/07/13	11/20/13	
186	Project 2010-04	Project 2010-04 Demand Data (MOD C)	MOD-031-1	Formal	10/09/13	11/22/13	Yes 11/22/13
187	Project 2013-04	Project 2013-04 Voltage and Reactive Control	VAR-001-4, VAR-002-3	Formal	10/11/13	11/25/13	Yes 11/25/13
188	Project 2009-03	Project 2009-03 Emergency Operations	SAR	Informal	11/06/13	12/05/13	Yes 12/5/13
189	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves	BAL-002-2	Formal	10/28/13	12/11/13	Yes 12/11/13
190	Project 2007-11	Project 2007-11 - Disturbance Monitoring	PRC-002-2	Formal	11/01/13	12/16/13	Yes 12/16/13
191	Project 2007-06	Project 2007-06 - System Protection Coordination	PRC-027	Formal	11/04/13	12/18/13	Yes 12/18/13
192	Project 2014-01	Project 2014-01 - Standards Applicability for Dispersed Generation Resources	SAR	Formal	11/20/13	12/19/13	Yes 12/19/13
193	Project 2010-01	Project 2010-01 Training - PER-005-2	PER-005-2	Formal	12/4/13	1/22/14	Yes 1/17/14
194	Project 2010-03	Project 2010-03 Modeling Date - MOD B	MOD-033-1	Formal	12/6/13	1/22/14	Yes 1/21/14
195	Project 2008-12	Project 2008-12 Coordinate Interchange Standards	INT-004-3 INT-010-2	Formal	1/10/14	1/24/14	Yes 1/22/14
196	Project 2007-02	Project 2007-02 Operating Personnel	COM-002-4	Formal	1/22/14	1/31/14	Yes 1/31/14
197	Project 2014-02	Project 2014-02 Standard Authorization Request – Cyber Security Standards	CIP SAR	Informal	1/17/14	2/18/14	Yes 2/18/14
198	2014 Work Plan	2014 Work Plan for NERC Reliability Standards Development	2014 Work plan			2/21/13	Yes 2/21/14

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199	Project 2010-17	Project 2010-17 Definition of Bulk Electric System - Phase 2	BES	Informal	1/29/14	2/27/14	Yes 2/27/14
200	Project 2010-05.1	Project 2010-05.1 Protection System: Phase 1 (Misoperations) - PRC-004-3	PRC-004-3	Formal	1/17/14	3/11/14	Yes 3/2/14
201	Project 2012-13	Project 2012-13 NUC-Nuclear Plant Interface Coordination Standard Authorization Request	NUC-001-2.1 SAR	Informal	2/12/14	3/13/14	Yes 3/13/14
202	Project 2010-05.2	Project 2010-05.2 Special Protection Systems (Phase 2 of Protection Systems) - SAR	SAR	Informal	2/18/14	3/19/14	Yes 3/19/14
203	Project 2014-03	Project 2014-03 - Revisions to TOP/IRO Reliability Standards	SAR	Formal	02/21/14	03/24/14	Yes 3/24/14
204	Project 2014-03	Technical Conferences on Revisions to TOP/IRO Reliability Standards	Technical Conference Topics	Informal	03/11/14	03/24/14	
205	Project 2014-04	Project 2014-04 - Physical Security	SAR	Informal	03/21/14	03/28/14	Yes 3/28/14
206	Project 2010-14.2	Project 2010-14.2 - Periodic Review of BAL Standards	Reco to Revise BAL-005 and BAL-006	Formal	02/21/14	04/07/14	
207	2010-05.2	Project 2010-05.2 - Phase 2 of Protection Systems - Revised Definition of Special Protection System	SPS Definition	Informal	03/11/14	04/09/14	Yes 4/9/14
208	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	MOD-031-1	Formal	02/25/14	04/10/14	Yes 4/10/14
209	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4, VAR-002-3	VAR-002-3	Formal	02/27/14	04/14/14	Yes 4/14/14
210	Project 2008-02	Project 2008-02 - Undervoltage Load Shedding - PRC-010, PRC-020, PRC-021 and PRC-022	PRC-010-1	Informal	03/17/14	04/16/14	Yes 4/16/14

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211	Project 2014-04	Project 2014-04 Physical Security - CIP-014-1	CIP-014-1	Formal	04/10/14	04/24/14	Yes 4/24/14
212	Project 2009-03	Project 2009-03 Emergency Operations – EOP-011-1	EOP-011-1	Informal	03/28/14	04/28/14	Yes 4/28/14
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	Formal	05/19/14	07/02/14	Yes 7/2/14

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			IRO-008-2 IRO-010-2 IRO-014-3 IRO-017-1				
224	Project 2014-02	Project 2014-02 CIP Version 5 Revisions – Cyber Security Standards	CIP-002 to CIP-011	Formal	06/02/14	07/17/14	Yes 7/16/14
225	Project 2015-2017	Project 2015-2017 Reliability Standard 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	PRC-005-X	Formal	07/30/14	09/12/14	

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		Maintenance and Testing – Phase 3 (Sudden Pressure Relays) – PRC-005-X					Yes 9/12/14
234	Project 2014-03	Project 2014-03 Revisions to TOP-IRO Reliability Standards	TOP-001-3 TOP-002-4 TOP-003-3 IRO-001-4 IRO-002-4 IRO-008-2 IRO-010-2 IRO-014-3 IRO-017-1	Formal	08/6/14	09/19/14	Yes 9/22/14
235	Project 2010-14.1	Project 2010-14.1 Balancing Authority Reliability-based Control	BAL-002-2	Formal	08/19/14	10/03/14	Yes 10/2/14
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

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244	Project 2007-06	Project 2007-06 System Protection Coordination PRC-027-1 (Preliminary Draft 5)	PRC-027-1	Informal	10/01/14	10/21/14	Yes 10/21/14
245	Project 2007-11	Project 2007-11 Disturbance Monitoring	PRC-002-2	Formal	09/05/14	10/21/14	Yes 10/21/14
246	Project 2014-01	Project 2014-01 Applicability for Dispersed Generation	PRC-004-2.1a(X) PRC-004-4	Formal	09/05/14	10/22/14	Yes 10/22/14
247	Project 2014-03	Project 2014-03 Revisions to TOP/IRO Reliability Standards TOP-001-3	TOP-001-3	Formal	10/10/14	11/10/14	Yes 11/10/14
248	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation TPL-007-1	TPL-007-1	Formal	10/28/14	11/21/14	Yes 11/24/14
249	Project 2010-13.3	Project 2010-13.3 – Relay Loadability: Stable Power Swings	PRC-026-1	Formal	11/04/14	11/24/14	Yes 11/25/14
250	Project 2014-01	Project 2014-01 – Standards Applicability 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	White Paper Appendix A Appendix B	Informal	12/22/14	1/20/15	Yes 1/20/15

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		Dispersed Generation Resources					
255	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	PRC-005-5	Informal	12/22/14	1/20/15	Yes 1/22/15
257	Project 2010-14.1	Project 2010-14.1 Balancing Authority Reliability-based Control	BAL-002-2	Formal	1/29/15	3/18/15	Yes 3/16/15
258	Reliability Guideline	Reliability Guideline: Loss of Real-Time Reliability Tools Capability/Loss of Equipment Significantly Affecting ICCP Data		Formal	2/19/15	4/6/15	Yes 4/6/15
259	Project 2008-02.2	Project 2008-02.2 Phase 2 UVLS: Misoperation	PRC-010-2	Formal	2/20/15	4/7/15	Yes 4/7/15
260	Project 2014-04	Project 2014-04 Physical Security	CIP-014-2	Formal	2/20/15	4/9/15	Yes 4/9/15
261	Project 2015-04	Project 2015-04 Alignment of Terms	SAR	Formal	2/24/15	4/13/15	Yes 4/13/15
262	Project 2007-17.4	Project 2007-17.4 PRC-005 Order No. 803 Directives	SAR	Informal	3/12/15	4/10/15	Yes 4/13/15
263	Project 2015-06	Project 2015-06 Interconnection Reliability Operations and Coordination	SAR	Informal	3/16/15	4//15/15	Yes 4/15/15
264	Project 2010-14.2.2	Project 2010-14.2.2 Phase 2 of Balancing Authority Reliability-based Controls: Time Error Correction	SAR	Informal	3/17/15	4//15/15	Yes 4/15/15
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	EOP-005-2	Informal	3/27/15	5/11/15	Yes 5/11/15

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		Emergency Operations					
268	Project 2015-02	Project 2015-02 Periodic Review of Emergency Operations	EOP-004-2	Informal	3/27/15	5/11/15	Yes 5/11/15
269	Project 2007-06	Project 2007-06 System Protection Coordination PRC-027-1 (Draft 5)	PRC-027-1	Formal	4/1/15	5/15/15	Yes 5/15/15
270	Project 2010-04.1	Project 2010-04.1 MOD-031 FERC Order No. 804 Directives	SAR	Informal	4/16/15	5/19/15	Yes 5/19/15
271	Project 2010-05.3	Project 2010-05.3 Phase 3 of Protection Systems – RAS	PRC-012-2	Informal	4/30/15	5/20/15	Yes 5/20/15
272	Project 2015-03	Project 2015-03 Periodic Review of System Operating Limit Standards	FAC-010-3 FAC-011-3 FAC-014-2	Formal	5/4/15	6/17/15	Yes 6/17/15
273	Project 2015-06	Project 2015-06 Interconnection Reliability Operations and Coordination	IRO-006-East-2 IRO-009-2	Formal	5/21/15	7/8/15	Yes 7/8/15
274	Project 2007-17.4	Project 2007-17.4 PRC-005 FERC Order No. 803 Directive	PRC-005-3	Formal	6/11/15	7/10/15	Yes 7/10/15
275	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generations Resources	PRC-004-2.1 PRC-005-2 PRC-005-3	Informal	6/12/15	7/13/15	Yes 7/13/15
276	Project 2015-07	Project 2015-07 Internal Communications Capabilities	COM-001-2	Informal	6/11/15	7/15/15	Yes 7/15/15
277	Project 2015-04	Alignment of Terms	Glossary Terms	Formal	6/12/15	7/23/15	Yes 7/23/15
278	Project 2009-02	Real-time Monitoring and Analysis Capabilities	SAR	Formal	7/16/15	8/17/15	Yes 8/17/15
279	NERC 2016-2018	Reliability Standards Development Plan	Development Plan	Formal	7/16/15	8/17/15	Yes 8/17/15
280	Project 2015-08	Emergency Operations	EOP-004-2 EOP-005-2 EOP-006-2 EOP-008-1	Informal	7/21/15	8/19/15	Yes 8/19/15

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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 2010-14.2.2	Phase 2 of Balancing Authority Reliability-based Controls: Time Error Correction	BAL-004-0	Survey	8/12/15	8/25/15	Yes 8/25/15
283	Project 2007-06.2	Phase 2 of System Protection Coordination	TOP-009-1	Formal	7/29/15	9/11/15	Yes 9/11/15
284	Project 2007-06	System Protection Coordination	PRC-027-1	Formal	7/29/15	9/11/15	Yes 9/11/15
285	Project 2010-14.2.1	Phase 2 of Balancing Authority Reliability-based Controls	BAL-005-1 BAL-006-3	Formal	7/30/15	9/14/15	Yes 9/14/15
286	Project 2007-17.4	PRC-005 FERC Order No. 803 Directive	PRC-005-6	Formal	7/30/15	9/16/15	Yes 9/16/15
287	Project 2010-04.1	MOD-031 FERC Order No. 804 Directives	MOD-031-2	Formal	7/31/15	9/18/15	Yes 9/18/15
288	Project 2015-09	Establish and Communicate System Operating Limits	FAC-010-3 FAC-011-3 FAC-014-2	Informal	8/20/15	9/21/15	Yes 9/21/15
289	Project 2010-07.1	Vegetation Management	FAC-003-3	Informal	8/24/15	9/28/15	Yes 9/28/15
290	Project 2010-05.3	Phase 3 of Protection Systems: Remedial Action Schemes	PRC-012-2	Formal	8/20/15	10/5/15	Yes 10/5/15
291	Project 2009-02	Real-time Reliability Monitoring and Analysis Capabilities	IRO-018-1 TOP-010-1	Formal	9/24/15	11/9/15	Yes 11/9/15
292	Project 2010-14.2.2	Phase 2 of Balancing Authority Reliability-based Controls	BAL-004-0	Formal	9/24/15	11/12/15	Yes 11/12/15
293	Project 2015-07	Internal Communications Capabilities	COM-001-3	Formal	9/25/15	11/16/15	Yes 11/16/15
294	Project 2007-06.2	Phase 2 of System Protection Coordination	TOP-009-1	Formal	10/6/15	11/19/15	Yes 11/19/15
295	Project 2010-07.1	Vegetation Management	FAC-003-3	Formal	10/30/15	12/16/15	Yes 12/16/15
296	Project 2015-10	Single Points of Failure SAR	TPL-001	Informal	11/12/15	12/17/15	Yes 12/17/15

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297	Project 2010-05.3	Phase 3 of Protection Systems RAS	PRC-012-2	Formal	11/25/15	1/8/16	Yes 1/8/16
298	Project 2010-14.2.1	Phase 2 of Balancing Authority Reliability-based Controls	BAL-005-1 FAC-001-3 BAL-006-2	Formal	12/31/15	1/11/16	Yes 1/11/16
299	Project 2009-02	Real-time Reliability Monitoring and Analysis Capabilities	IRO-018-1 TOP-010-1	Formal	12/10/15	1/25/16	Yes 1/25/16
300	Project 2016-01	Modifications to TOP and IRO Standards	SAR	Informal	1/22/16	2/22/16	Yes 2/22/16
301	Project 2010-05.3	Phase 3 of Protection Systems RAS	PRC-012-2	Formal	2/3/16	3/18/16	Yes 3/18/16
302	Project 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	Formal	6/30/16	8/15/16	Yes 8/15/16

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			EOP-008-2				
315	Project 2016-02	Modifications to CIP Standards	CIP-003-7	Formal	7/21/16	9/6/16	Yes 9/6/16
316	FMAG	Functional Model Advisory Group	Reliability Functional Model and Technical Document	Informal	7/21/16	9/7/16	Yes 9/7/16
317	Project 2015-08	Emergency Operations	EOP-004-4	Formal	7/25/16	9/8/16	Yes 9/8/16
318	Project 2015-INT-01	Interpretation of CIP-002-5.1 for Energy Sector Security Consortium (EnergySec)	CIP-002-5.1	Formal	7/27/16	9/12/16	Yes 9/12/16
319	Project 2016-01	Modifications to TOP and IRO Standards SAR	TOP-001-3 IRO-002-4	Formal	8/31/16	10/17/16	Yes 10/14/16
320	Project 2016-04	Modifications to PRC-025-1 SAR	PRC-025-1	Formal	9/16/16	10/18/16	Yes 10/18/16
321	Project 2016-03	Cyber Security Supply Chain Management	SAR	Informal	10/20/16	11/18/16	Yes 11/18/16
322	Project 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	VAR-001-4.1	Formal	2/28/17	4/13/17	Yes 4/13/17

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
		and Reactive (VAR) Standards					
334	Project 2016-EPR-02	Enhanced Periodic Review of Voltage and Reactive (VAR) Standards	VAR-002-4	Formal	2/28/17	4/13/17	Yes 4/13/17
335	SPM	Revisions to the NERC Standard Processes Manual	SPM	Formal	3/20/17	5/3/17	Yes 5/3/17
336	Project 2015-10	Single Points of Failure	TPL-001-5	Informal	4/25/17	5/24/17	Yes 5/24/17
337	Project 2016-03	Cyber Security Supply Chain Risk Management	CIP-005-6 CIP-010-3 CIP-013-1	Formal	5/2/17	6/15/17	Yes 6/15/17
338	Project 2017-01	Modifications to BAL-003-1.1 SAR	BAL-003-1.1	Formal	6/19/17	7/18/17	Yes 7/18/17
339	Project 2017-06	Modifications to BAL-002-2 SAR	BAL-002-2	Informal	6/20/17	7/20/17	Yes 7/20/17
340	Project 2017-02	Modifications to Personnel Performance, Training and Qualifications Standards	PER-003-1 PER-004-2	Informal	6/21/17	7/24/17	Yes 7/24/17
341	2018-2010	Reliability Standards Development Plan		Formal	6/22/17	7/25/17	Yes 7/26/17
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

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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 Limits	FAC-010 FAC-011 FAC-014	Formal	9/29/17	11/13/17	Yes 11/13/17
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

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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
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

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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 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	Formal	2/27/19	4/12/19	Yes 4/12/19
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	Formal	10/29/19	12/12/19	Yes 12/12/19

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
			MOD-033-2 NUC-001-4 PRC-006-4 TOP-003-4				
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 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	11/4/19	12/18/19	Yes 12/18/19
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

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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 IRO-008-3	Formal	6/19/20	8/3/20	Yes 8/3/20
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

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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
439	Project 2021-05	Modifications to PRC-023	PRC-024	Informal	6/29/21	7/28/21	Yes 7/28/21
440	Project 2021-06	Modifications to IRO-010 and TOP-003	IRO-010-2 TOP-003-3	Informal	7/8/21	8/6/21	Yes 8/6/21
441	Project 2019-04	Modifications to PRC-005-6 SAR	PRC-005-6	Formal	7/27/21	8/25/21	Yes 8/25/21
442	2022-2024	Reliability Standards Development Plan	Reliability Standards Development Plan	Informal	7/30/21	8/30/21	Yes 8/30/21
443	Project 2016-02	Modifications to CIP Standards	CIP-002-7 CIP-003-Y CIP-004-Y CIP-005-8 CIP-006-7 CIP-007-7 CIP-008-7 CIP-009-7 CIP-010-5 CIP-011-Y CIP-013-3	Formal	6/30/21	9/1/21	Yes 9/1/21
444	Project 2020-03	Supply Chain Low Impact Revisions	CIP-003-8	Formal	8/27/21	10/11/21	Yes 10/11/21
445	Project 2021-07	Extreme Cold Weather Grid Operations, Preparedness, and Coordination	BAL EOP IRO TOP Or Other Standards	Formal	11/22/21	12/21/21	Yes 12/21/21
446	Project 2020-04	Modifications to CIP-012	CIP-012	Formal	11/30/21	1/24/22	Yes 1/24/22
447	Project 2020-05	Modifications to FAC-001-3 and FAC-002-2	FAC-001 FAC-002	Formal	12/7/21	1/31/22	Yes 1/31/22
448	Project 2021-06	Modifications to IRO-010 and TOP-003	IRO-010 TOP-003	Informal	1/11/22	2/9/22	Yes 2/9/22
449	Project 2020-02	Modifications to TPL-001-5.1 and MOD-032-1	TPL-001-5.1 MOD-032-1	Informal	2/1/22	3/2/22	Yes 3/2/22
450	Project 2022-01	Reporting ACE Definition and Associated Terms	SAR	Informal	2/9/22	3/10/22	Yes 3/10/22
451	Project 2021-02	Modifications to VAR-002	SAR	Informal	3/9/22	4/6/22	Yes 4/6/22

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
452	Project 2016-02	Modifications to CIP Standards	CIP-002-7 CIP-003-Y CIP-004-Y CIP-005-8 CIP-006-7 CIP-007-7 CIP-008-7 CIP-009-7 CIP-010-5 CIP-011-Y CIP-013-3	Formal	2/18/22	4/11/22	Yes 4/11/22
453	Project 2020-03	Supply Chain Low Impact Revisions	CIP-003-8	Formal	2/25/22	4/15/22	Yes 4/15/22
454	2022 Standards Grading	Standards Grading	PER-003-2 PER-005-2 PER-006-1 TPL-007-4	Informal	4/20/22	6/3/22	Yes 6/3/22
455	Project 2021-07	Extreme Cold Weather Grid Operations, Preparedness, and Coordination	EOP-011-3 EOP-012-1	Formal	5/19/22	6/21/22	Yes 6/17/22
456	Project 2020-06	Verifications of Models and Data for Generators	MOD-26-2	Formal	5/20/22	7/6/22	Yes 7/6/22
457	Project 2020-02	Modifications to PRC-024 (Generator Ride-through)	PRC-024-3	Formal	5/31/22	7/14/22	Yes 7/14/22
458	Project 2022-03	Energy Assurance with Energy-Constrained Resources	EOP and TOP	Informal	6/22/22	7/21/22	Yes 7/21/22
459	Project 2021-04	Modifications to PRC-002	PRC-002	Formal	6/9/22	7/25/22	Yes 7/25/22
460	Project 2020-03	Supply Chain Low Impact Revisions	CIP-003-8	Formal	7/6/22	8/19/22	Yes 8/19/22
461	Draft 2023-2025	Reliability Standards Development Plan	RSDP	Formal	7/26/22	8/24/22	Yes 8/24/22
462	Project 2021-07	Extreme Cold Weather Grid Operations, Preparedness, and Coordination	EOP-012-1	Formal	8/3/22	9/1/22	Yes 9/1/22
463	Project 2017-01	Modifications to BAL-003 – Phase II	BAL-003-2	Formal	7/25/22	9/7/22	Yes 9/7/22
464	Project 2022-04	EMT Modeling SAR	FAC-002 MOD-032 TPL-001	Formal	8/11/22	9/13/22	Yes 9/13/22
465	Project 2016-02	Modifications to CIP Standards	CIP-002-7 CIP-003-Y CIP-004-Y CIP-005-8 CIP-006-7	Formal	8/17/22	10/7/22	Yes 10/7/22

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
			CIP-007-7 CIP-008-7 CIP-009-7 CIP-010-5 CIP-011-Y CIP-013-3				
466	Project 2021-04	Modifications to PRC-002	PRC-002-3	Formal	9/26/22	11/10/22	Yes 11/10/22
467	Project 2020-04	Modifications to CIP-012	CIP-012	Formal	10/3/22	11/16/22	Yes 11/16/22
468	Project 2021-01	Modifications to MOD-025 and PRC-019	MOD-025-2 PRC-019-2	Formal	9/29/22	11/17/22	Yes 11/17/22
469	Project 2021-05	Modifications to PRC-023	PRC-023-6	Formal	10/10/22	12/2/22	Yes 12/2/22

Note: RSC past comment forms are posted on the NPCC Website under "Standards - Regional Standards Comments."

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